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Stuck Pipe Non Productive Time Reduction by Application of Intelligent Technologies to Replace Conventional Drillstring Separation Methods

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Abstract

Sticking a Drilling BHA and subsequent loss of tools, hole footage and potentially jeopardizing well objectives, is THE most costly unplanned drilling event that can occur to an Operator. It still tops the table of costly NPT events ahead of items such as Well Control incidents, waiting on weather (WOW), lost circulation, equipment failures and rig associated problems. The cost to the industry is estimated at several billions $USD per year. This is probably conservative and in the Gulf of Mexico alone in 2007, it was predicted to be 3% of the total spend on upstream oilfield equipment and services or $7.8 Billion (Tollefson et al 2008).

Operators routinely apply a margin between 10% and 25% to their well AFE's to account for unscheduled events (York et al, 2009). This can significantly affect drilling budgets where technical and operational risk must be balanced with potential return on Investment (ROI). The technological advance into extreme hostile territory, deepwater and HPHT makes the investment and risk higher to the extent that some wells do not get drilled. Deepwater wells are often incurring spread dayrates for services including the rig of $1M USD per day. Deepwater well AFE's can routinely exceed $100M and accounting for unscheduled events like stuck pipe with the integral uncertainties of recovery, can tip the balance and make the ROI unattractive.

Stuck pipe awareness courses and application of best drilling practices can be effective at reducing stuck pipe events but are wholly dependent on human factors and, therefore, exposed to inconsistencies and interpretation. Stuck pipe is a reality and the success of a recovery plan depends on a number of issues of which the most important is the efficient separation of the drillstring at the most beneficial point. The recovery timeline can be more effectively planned once the drillstring has been separated from the stuck BHA components. All recovery options are dependent on this critical operation.

Current technology is the same as it has been since the start of this industry albeit more advanced in its efficiency. Mechanical back offs, explosives or chemical cutting, are still the only methods to separate the drillstring usually requiring mobilization of specialist equipment and personnel. Limitations in wellbore inclination, drillstring internal dimensions, bottom hole pressure and temperature and Service Operator capability are factors influencing the chances of success. Critical to recovery options is the length of open hole exposure time without pipe movement or circulation. Conventional means of pipe separation can take several days to effect; meanwhile the wellbore may be deteriorating further hampering recovery options.

This paper discusses the application and development of an integral (to the BHA and DP) circulation and disconnect tool that can sense its environment, receive downlinks to open/close a multi position circulating valve, process sensory information to establish tool status, stuck or free, ultimately receiving a command to disconnect from the BHA or wherever it is positioned in the string. The disconnect is effected by electro / mechanical means and represents a step change in application of this technology for this purpose, removing any form of surface intervention or the requirement for 3rd party specialist equipment or personnel, leaving the Operator in control of the event.

Introduction

Global statistics for stuck pipe are not readily accessible but regional data collated from collaborative operators gives an indication of the scale of the issue. One major Middle East Operator calculated it accounted for 25% of their NPT with a cost of 2 rig years per annum (Muqeem, 2012). In the Gulf of Mexico, statistics gathered estimated a total $7.6 billion USD would be spent on stuck pipe issues (Tollefson et al, 2008). In addition, data collected by the James K Dodson Company for Gulf of Mexico deepwater operations between 2004-2009 (York, 2009), calculated that 5.6% of total well time of Pre Salt wells would be spent on wellbore stability issues and 12.6% on Sub Salt wells. Extrapolating this to todays potential $100M deepwater well cost, this could be anything between $6M and $12M spent on wellbore stability issues including stuck pipe related issues per well. Analysis of data gathered from a database of 27,000 bit runs in US Land operations (Robson, 2012) showed an increasing trend in stuck pipe incidents since 2010, correlating with an increase in well complexity. It also concluded that the increasing activity and lack of skilled personnel may be an influence.

Lost circulation and stuck pipe are governed by numerous factors that make finding analytical solutions with acceptable accuracy very difficult or impossible (Moazzeni, 2011). There is no doubt that stuck pipe and the issues that lead to stuck pipe, for example, inadequate hole cleaning are still major causes for concern in any drilling operation. The drive to drill deeper, in more hazardous environments with the inherent huge costs associated with NPT (Chatar, 2010) drives the necessity to develop technology that can reduce risk and uncertainty. The technology and ingenuity that drove the development of drilling tools like Rotary Steerables and modern LWD tools can be applied to the more fundamental drilling operations like optimizing wellbore circulation through electronic variable circulating subs and effecting a surface controlled, non invasive, disconnect using intelligent electro/mechanical BHA tools.

Economics of Stuck Pipe

The cost of a stuck pipe incident in its entirety is a function of operations spread rate (rig plus services), Lost in Hole (LIH) cost of the stuck BHA and duration of recovery attempts. The final cost will depend on the outcome of the recovery i.e. was the BHA recovered and drilling continued (best outcome) or was the hole plugged back and sidetracked with the BHA lost. The final outcome will depend on many factors which are specific to each operation and situation. The course of action will also depend on an assessment of the chances of success to recover the stuck BHA. The initial assessment will take into account the following conditions:

1. Sticking mechanism – hole geometry (ledging, Key seats etc.), hole cleaning (cuttings bed), unstable wellbore (geo-mechanics)
2. Hole inclination – vertical, high inclination > 60 degs, horizontal.
3. Hole depth and size – small hole at greater depth is less likely to yield recovery success.
4. Drilling Rig capability – expertise of rig crew and quality of drilling equipment.

When taking all those factors into account a decision can be made whether or not the BHA stands a good chance of being recovered. A chance of recovery factor could be assigned i.e. 50/50, 60/40, 70/30 etc. There are more in depth mathematical relationships that could be explored but at the end of the day, it is a judgment decision.

The move into deep water and higher risk wells demanding high tech solutions and top class equipment has resulted in higher spread costs. A 5th / 6th generation deepwater operation may have a spread cost in excess of $1M per day and a modern 400ft water depth Jack up may have a spread cost of up to $350K per day. This has a fundamental effect on the economics of attempting to fish a BHA. Clearly if a basic rotary drilling BHA with an LIH of less than $1M gets stuck on a deepwater operation with a spread rate of $1M per day, then depending on the results of the recovery assessment, the most economic way forward may be to get off the BHA and sidetrack immediately. Conversely, the same BHA stuck on a land rig operation with a spread cost of $125k per day, it may be worthwhile, depending on the recovery assessment, to attempt a recovery.

In addition to the economics of the spread rate/LIH cost/chances of recovery factors, there is a consequential value that must be assessed. This could concern the loss of Radio Active sources and regional legislation where it must be seen that every attempt to recover the sources has been made. Economics is not a factor in this case. There is also the consequence of a sidetrack. There are certain scenarios where a sidetrack is not the best economical solution e.g. a long horizontal section that may have to be redrilled in its entirety because the DP can only be disconnected in a lower inclination section, higher up the hole.

Economic Scenario Examples

Table 1 shows a basic comparison of economies when considering recovering from a stuck RSS / LWD BHA on a 10,000ft vertical deepwater well. The Chance of Recovery Factor has been assessed as high and assuming this turns out to be correct, it makes economic sense to attempt to recover the BHA as opposed to plug back and sidetrack.

Hole depth	10000ft
LIH Cost of BHA	$2,500,000
Spread cost of Operation	$1,000,000

RECOVER BHA	DAYS	SIDETRACK	DAYS
POH recovered drillstring	0.5	POH recovered drillstring	0.5
RIH fishing BHA	0.7	RIH cement stinger	0.7
Jar fish free	0.5	Plug back and POH	1
POH with fish	1	RIH drilling BHA	0.7
RIH drilling BHA	0.7	Sidetrack and redrill	1
TOTAL	3.4	TOTAL	3.9
COST	**$3,400,000**	**COST**	**$6,400,000**

Table 1. Deepwater Vertical Well – High Recovery Factor

Hole depth	20000ft
LIH Cost of BHA	$1,000,000
Spread cost of Operation	$1,000,000

RECOVER BHA	DAYS	SIDETRACK	DAYS
POH recovered drillstring	1	POH recovered drillstring	1
RIH fishing BHA	1.2	RIH cement stinger	1.2
Jar fish free	1	Plug back and POH	1.4
POH with fish	2	RIH drilling BHA	1.2
RIH drilling BHA	1.2	Sidetrack and redrill	1
TOTAL	6.4	TOTAL	5.8
COST	**$6,400,000**	**COST**	**$6,800,000**

Table 2. Deepwater Inclined Well – Low Recovery Factor

Table 2 shows a basic comparison of economies when considering recovering from a stuck lower cost BHA on a 20,000ft inclined deepwater well. The Chance of Recovery Factor has been assessed as low and assuming this turns out to be correct, it is less clear as to the best course of action. It would be more pragmatic to opt for the sidetrack, as the operations sequence is more predictable rather than opt for recovering the BHA with a low chance of success and waste 2-3 days rig time. The above examples only demonstrate some basic scenarios and each case would have to be assessed on its own merits. However, there is one thing that ALL scenarios have in common and is a fundamental step when considering the best course of action.

Every recovery from a terminal stuck pipe situation DEPENDS upon the successful separation of the drillstring from the stuck BHA. What is NOT detailed in the above tables is the time spent working the BHA when initially stuck, acceptance that it is not going to come free and the time taken to back off the drillstring so that the recovery process can begin.

Drillstring Separation Current Methods

Before any recovery can commence, the BHA must be separated from the drillstring. This is normally achieved using explosives or chemicals. Most Operators will have an Explosives Box onboard or on site with a collection of explosives designed to perform various functions. This is usually tubing punchers to perforate the drillpipe to enable circulation, detonating cord which can be used as a “string shot” to “hammer” a drillpipe connection loose or Colliding charges which are shaped explosives which when correctly deployed will sever either the drillpipe or drill collars. To enable their deployment an electric wireline unit and specialist technicians are required. This may require specific mobilization of personnel which depending on the location could be anything from 6hrs to several days.

The Operator will normally run a Free Point Indicator tool inside the drillpipe to indicate where the stuck point is. An attempt to back off the drillpipe will be made just above the stuck point usually by applying left hand torque to the DP and placing a Stringshot via electric line opposite the connection to be backed off. The hope is that the hammer like explosive blow will undo the connection. Several attempts may be required. In high inclination holes the left hand torque may not get transmitted down to the stuck point and a severing charge is used to “cut” the drillpipe. Sometimes it does not go according to plan and results are obtained as depicted in Figure 1.

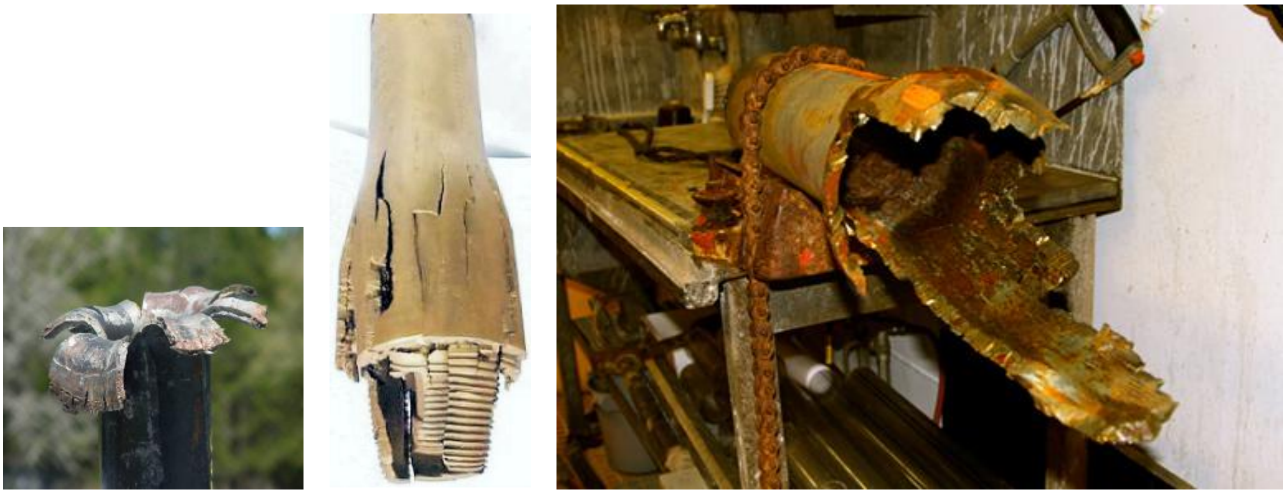


Figure 1 – examples of severed Drillpipe.

Results as in Figure 1 more or less write off any chance of being able to reconnect with the fish and a sidetrack is inevitable. There have been significant advances in the technology of cutting and severing stuck tubulars (Segura, 2011), however, explosive jet cutters and chemical cutters which can produce a cleaner cut usually have to be specifically mobilized and engineered for each application. Depending on rig location this could take several days. In the case of chemical cutters, these are rarely air transportable.

The disadvantages in wireline-deployed explosives to separate drillpipe are as follows:

1. Specialist technicians required to deploy the explosives.
2. Several attempts may be required.
3. Damage to top of fish left downhole.
4. Unable to access horizontal or greater than 65deg inclination hole sections.
5. Remote logistics may delay the start of the process.

With the advent of highly sophisticated downhole technology in the form of Rotary Steerable systems and LWD technology in combination with the huge daily cost of some of the high technology rigs, there is an opportunity to deploy intelligent non-invasive technology to reduce uncertainty and risk when performing this operation.

Application of Intelligent Technologies to Mitigate Stuck Pipe

There are several areas where modern technologies can be applied to improve drilling conditions that will reduce the chances of stuck pipe. Hole cleaning has always been a major issue in inclined wells where cuttings bed form and can lead to stuck pipe when attempting to trip out the hole. Annular velocity is one of the critical parameters that can improve cuttings bed removal but power hungry BHA's and bit hydraulics can sometimes compromise the ability to provide sufficient flow rate to clean the hole. A circulating sub is often installed above the BHA that can be opened to bypass the BHA and provide maximum flow rate to clean the hole. It can also be used to dump high concentrations of LCM in a lost circulation situation, that would otherwise block the BHA and bit nozzles. Almost all circulating subs are of a drop ball/dart type that have a limited number of cycles, usually 6. Balls have to be dropped to open and separate balls dropped to close. These subs have limitations when it comes to hole angle, as the balls require gravity to reach their seats. Also, in a packed off situation where the annulus is sealed around the BHA, the balls or dart sometimes do not reach their seat and the sub cannot be opened to try and relieve the pack off.

The limitations of these devices and methods appeared out of sync with technology advancements in other areas. Development of an electro / mechanical device with a multi-position circulating valve and ability to reliably disconnect via surface downlinking was commenced.

Electronic Multi Position Circulating Valve and Disconnect Device

The multiple position circulating valve can be configured to provide optimal annular velocity while drilling utilising all the available hydraulic power. The valve has 3 positions which can be opened to allow partial fluid bypass of the BHA while drilling, maximising the use of surface pressure limitations and optimising AV. At section TD, the valve can be put into the Full Open position and the well cleaned up at maximum flowrate bypassing the BHA. A second device can be positioned in the string at the end of the build up section when the bit is at TD. Once cuttings have been moved from the high inclination section into the build up section, the primary device can be closed and the secondary device opened to allow efficient cuttings transportation through the Build up section and lower overall ECD's. In addition, there is the assurance that the device is not limited by hole inclination, as there are no darts or balls to be dropped. The disconnect feature is particularly useful in high inclination and horizontal drilling which would be beyond the normal operating limits of wireline if an explosive back off were to be considered.

Therefore, the device provides the Operator with the ability to utilise a multi position circulating valve at any time during the drilling process without surface intervention i.e. No drop balls or darts. Integral with the tool is a Disconnect feature that allows the Operator to activate the mechanism and separate the lower half from the upper half in a stuck pipe situation. The device has the ability to sense its downhole environment through electronic sensors, process that information and move through various pre-defined modes and respond to surface Downlinks.

The concept behind the device is to provide controlled functions at the Operators discretion without the intervention of surface tools or mobilisation of 3rd parties and 3rd party equipment. The device has three distinct sections; the Disconnect section; the Electronic Service Module (ESM) and the Circulating valve. Each section is discussed below.

Electronic Service Module (ESM)

The ESM contains the triple axis accelerometers, pressure sensors, proximity sensors, electric drive motors, processors and battery pack to service the Disconnect and Circulate sections (Figure 2.). The sensor outputs are processed according to a Sensor Map (see Figure 4) which will define the required action. An example of a sensor map can be found later in this section and is fully customisable to the operator's needs and environment. At each end of the ESM there is an electric motor to drive the respective system, either disconnect or circulate.

Figure 2 – Electronic Service Module

The system is battery driven i.e. no turbines, therefore, the sensors, processor and motor current draw is being designed to be very low. The entire tool is through bore.

Disconnect Section

The Disconnect system is designed to recognise various "modes" and progress through them in sequence before entering the Disconnect mode where a confirmation signal from surface will activate the Disconnect motor. This system is to ensure that there is no accidental release. The sequence is explained below.

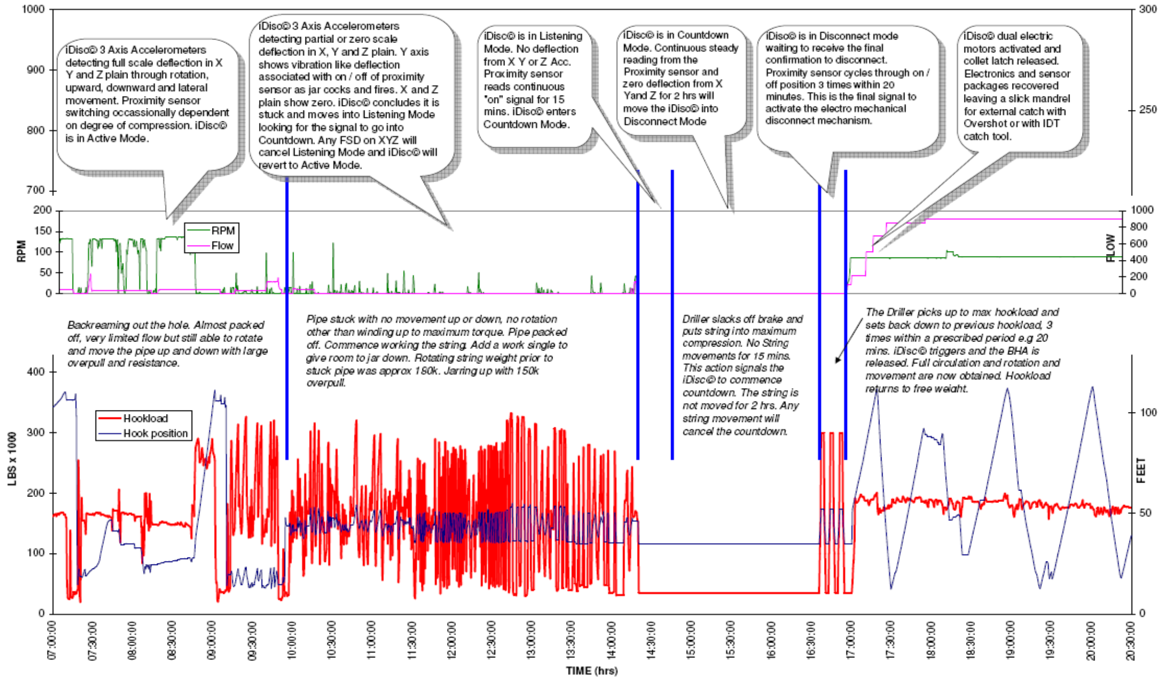


Figure 3 – Disconnect Process Chart

Please refer to the chart in Figure 3. The values on this chart are taken from an actual stuck pipe incident with the device modes inserted. The purpose of having a sequence of Modes that the tool must progress through prior to Disconnect as opposed to a simple command to Disconnect, are to ensure that the tool does not misinterpret signals and disconnect prematurely. The Modes are explained in the table below and are as follows:

Active Mode

In this mode the tool is below the rotary table and the hydrostatic pressure switch has switched the tool on when the tool is approximately 50ft below RT. All sensors are active and feeding data to the processor. In this mode, the tool recognises normal drilling activity such as drilling, reaming, pumping, tripping, backreaming etc.

Listening Mode

If the BHA becomes stuck, the sensors note the lack of movement and switching of the proximity sensor indicating jarring. After a period, the tool moves into a Listening mode where it is standing by for the signal to move into Countdown Mode. If any sensor detects movement then the tool reverts to Active Mode.

Countdown Mode

Once the tool is in Listening Mode, the next step in the sequence to disconnect is for the tool to enter into a Countdown. This is initiated by compressing the string to ensure the proximity sensor is closed or "on" for 15 minutes continuously. The tool will then go into a countdown to the next mode, Disconnect Mode. The countdown is fully customisable to the Operators spec but is suggested to be 2 hours. The string must be kept stationary. Any movement detected by the sensors will abort the Countdown. At the end of the Countdown, the tool will move into Disconnect Mode.

Disconnect Mode

The tool is now ready to receive the final signal to disconnect which it must receive in a pre-determined period of time suggested at 20 mins. The string is lifted into tension and then lowered into compression 3 times within the time period. Ultimately hall affect switches pick up on the linear movement to provide a final confirmation prior to activating the disconnect motors. Power is sent to the disconnect motor and the release mechanism activated.

Circulating Valve

This is controlled by the same sensors in the ESM but according to a different mapping. The valve has three positions which can be customised to operators needs in terms of hydraulics and flow area (see figure 6). The valve is not sequential therefore it can go from fully closed to fully open with one command.

Downlink

The tool can recognize a “downlink” through a timed sequence of specific rotations and prepare itself to function through three different positions according to the Operators needs. There are two phases of Operation; “Drilling” and “Stuck”. In the Drilling phase, the tool responds to downlinks as defined in the ESM Sensor Maps table below, however, if the tool becomes stuck, it cannot respond to downlinks as rotation will not be possible. In “Stuck” phase, the circulating valve can be opened to the full position as part of the Disconnect sequence. When the device enters the Countdown Mode, a sequence of signals is sent via the proximity sensor that tells the circulating valve to go to the full open position. This will automatically cancel the Countdown and the string attempted to circulate to move any pack off.

ESM Sensor Maps

iDisc								
MODE	*ACTIVITY*	*Acd lateral x*	*Acd Axial y*	*Acd Rotn z*	*Compression switch*	*Flow (differetial pressure)*	*Pressure switch*	*Comments*
Active	BHA Racked back	0	0	0	0	0	0	tool switched off
	BHA running in hole	1	1	1	0	0	1	tool switches on when pressure switch reads in excess of 10psi
	Reaming	1	1	1	0	1	1	pumps on, rotating, working in the hole
	Drilling	1	1	1	1/0	1	1	pumping, rotating, WOB
	Circulating	1/0	1	1/0	1/0	1	1	pumping, on/off rotn, moving string up and down
	Wiping	1	1	0	1/0	0	1	moving string through resistance to clean hole
	BHA static at casing shoe	0	0	0	0	0	1	string stationary
	BHA pulling out of hole	1	1	1	0	0	1	
Listening	BHA stuck & jarring	0	0	0	1/0	1/0	1	comp sensor cycling with jar action. Possible slight pressure surges due to jarring
Countdown	String put in compression to trigger the countdown	0	0	0	1	0	1	string put in compression and held stationary for X mins to trigger countdown
	Abort countdown (within countdown time period)	0	0	0	0	0	1	String lifted into tension aborting countdown
	Re-instate countdown after abort	0	0	0	1	0	1	string put in compression and held stationary for X mins to trigger countdown
Disconnect	Trigger disconnect	0	0	0	0,1,0,1,0,1	0	1	countdown period expired. Lift string into tension and back to compression 3 times within X mins
iCirc - Drilling								
Downlink	Prepare for Downlink	0	0	1 (30&60 rpm)	0	1 (300gpm)	1	constant pump rate, 30rpm for 1min followed by 60rpm for 1min, back to 30rpm
	listening for command sequence	0	0	1 (30rpm)	0	1 (300gpm)	1	tool waiting for pumps on/off sequence. Must be received within 5 mins from end of downlink signal
Command	Open 33%	0	0	1 (30rpm)	0	1 (300gpm),0 (0gpm)	1	pumps off for 30 secs, pumps back on. After 30 secs v/v should open and pressure drop observed at surface.
	End Downlink	0	1	1 (+rpm)	0	1	1	increase RPM and move string up or down
Command	Open 66%	0	0	1 (30rpm)	0	1 (300gpm),0 (0gpm)	1	pumps off, on, off, on. 30 sec intervals.
	End Downlink	0	1	1 (+rpm)	0	1	1	increase RPM and move string up or down
Command	Open 100%	0	0	1 (30rpm)	0	1 (300gpm),0 (0gpm)	1	pumps off, on, off, on,off,on. 30 sec intervals.
	End Downlink	0	1	1 (+rpm)	0	1	1	increase RPM and move string up or down
Command	Close 0%	0	0	1 (30, 60rpm)	0	1 (300gpm),0 (0gpm)	1	increase rpm to 60. Pumps off for 1min, then back on.
	End Downlink	0	1	1 (+rpm)	0	1	1	increase RPM and move string up or down
iCirc - Stuck								
Listening	BHA stuck & jarring	0	0	0	1/0	1/0	1/0	comp sensor cycling with jar action. Possible slight pressure surges due to jarring
Countdown	String put in compression to trigger the countdown	0	0	0	1	0	0	string put in compression and held stationary for X mins to trigger countdown
Command	100% open	0	0	0	1 (...---...)	0	0	once tool is in countdown mode (15mins static compression), the string is lifted and lowered to give a 3 short, 3 long, 3 short compressions (SOS). v/v will open 100%

Figure 4 – Sensor Map

Mechanical Design Circulating Valve

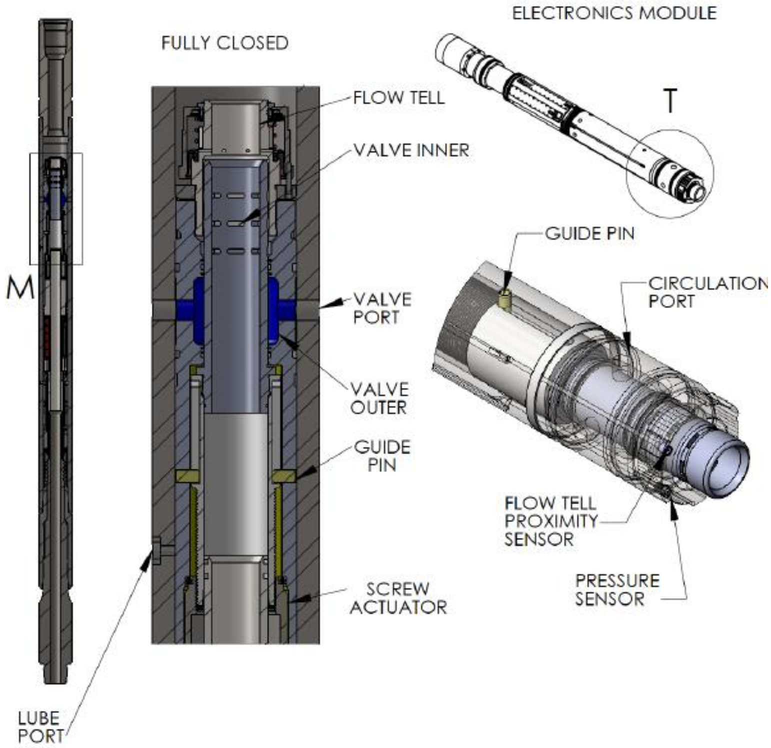


Figure 5 – Circulating Valve layout

The three position circulating valve is positioned at the top of the assembly (see Figure 5). Circulation can be routed to the annulus via the Valve Inner tube which can move down under command from the ESM, to expose the array of circulation ports to the external valve ports. Port sizing can be customised by the operator to suit a particular well design. When circulation commences, the Flow Tell switch activates to tell the ESM that there is flow. The tool is instructed to move to its various port positions by a serious of downlinks transmitted by sequences of RPM and pumps on/off. The sequences are outlined in the ESM Sensor Maps. Sensors confirm to the ESM the exact position of the Valve Inner tube. The tube is driven up and down by a screw actuator which is driven by an electric motor under the control of the ESM. The three circulating positions are shown below.

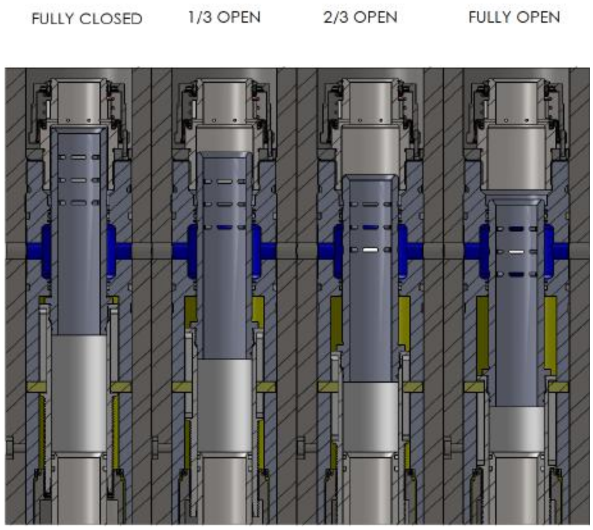


Figure 6 – Circulating Valve positions

Intelligent Disconnect

The Disconnect mechanism is at the lower end of the assembly below the ESM. When disconnected the ESM and Circulating valve mechanism are recovered. This leaves the “Stinger” looking up, for which a matching Fishing overshot can be supplied which will mate with the Stinger.

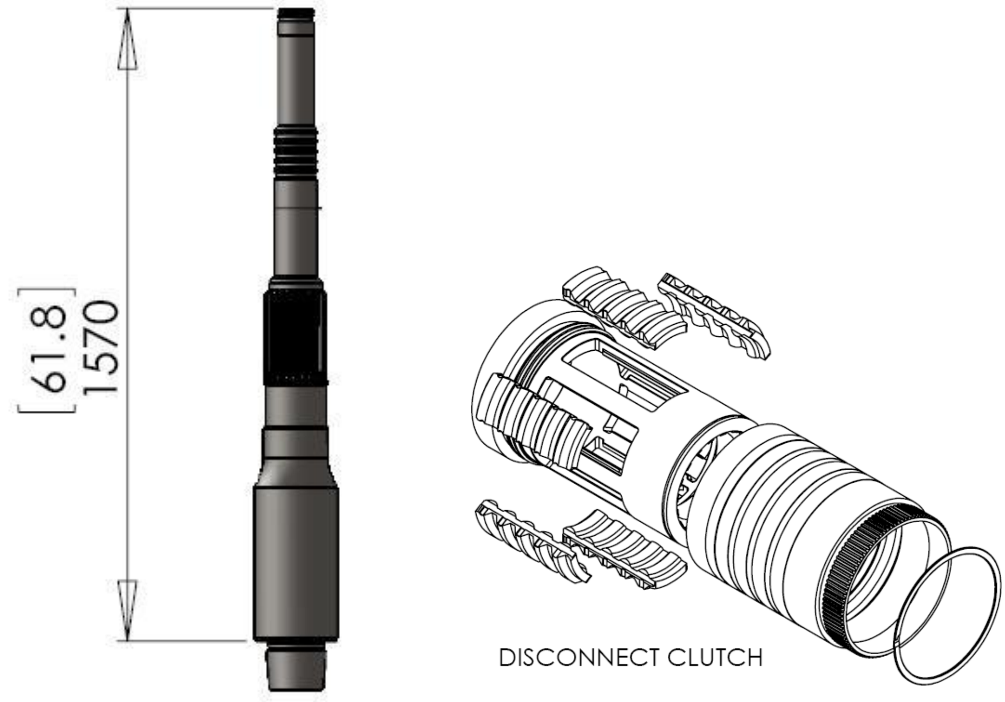


Figure 7 – Clutch Mechanism

The Stinger and the upper half of the assembly are connected by the segmented “Disconnect Clutch” as depicted in Figure 7. This has six segments which sit in a basket and the engineered waveform profile engages with a matching profile on the stinger. The segments are held in place by a retaining cylinder which has a matching waveform profile with the back of the clutch segments. The clutch is engaged when the retaining cylinder waveform profile is “crest to crest” with the clutch segments rear waveform profile (see Figure 8). This keeps the clutch and stinger waveforms fully meshed. The specially engineered waveform profile ensures uniform and equal distribution of tension and compression forces minimising stress concentrations. Torque and torsional forces are transmitted by a drive spline arrangement. The clutch is disengaged when the retaining cylinder is caused to move up and the waveform profile moves from “crest to crest” to “crest to trough”. The clutch segments then have enough room to move back from the stinger and fully disengage their waveforms. See drawings below:

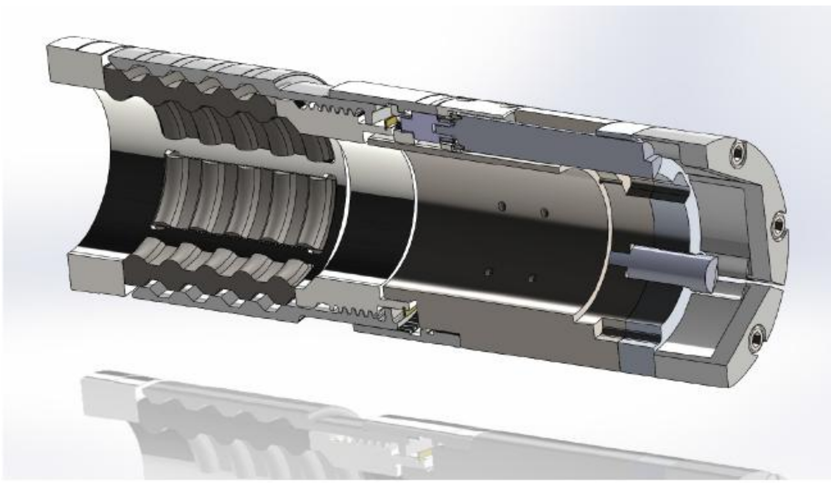


Figure 8 – Section through Clutch

With the clutch disengaged, the upper assembly consisting of the clutch, ESM and circulating v/v (connected to the drillstring) can be withdrawn from the stinger and lower BHA. The movement of the clutch segment retention collar is by a screw actuator driven by an electric motor.

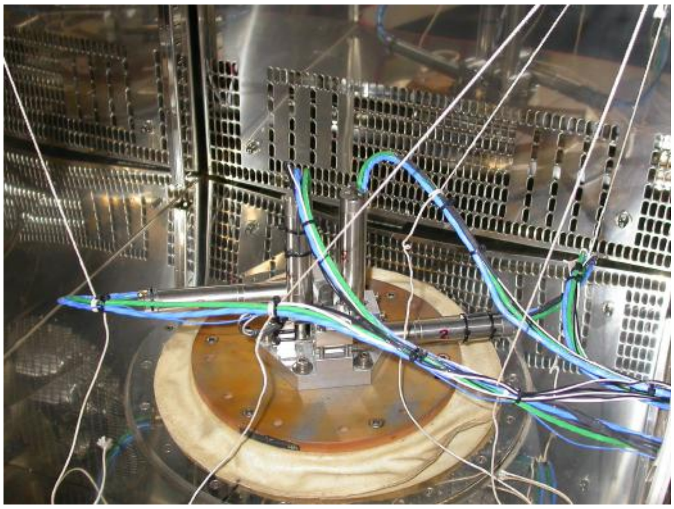
Electronics and Design Integrity

The design intent of the disconnect tool was to ensure that any component failure would not create a situation in which the tool would perform an unplanned disconnect, and also that when a disconnect action is required the mechanism would perform in a reliable manner. Due to the high vibration environment that can be encountered care has been taken to ensure the components are robust. One example is that the torque transmitted through the tool does not introduce stress near where disconnect collets are positioned. This region is further protected from adverse bending moments and compressive stresses, leaving the collets only taking tensile loads.

The tool body components Mandrel, Spline housing Main Body and Top sub are manufactured with alloy steels namely AISI4145H or AISI 4330V, in accordance to Fearnley Proctors NS-1 standard which exceeds the material testing requirements of DS-1 and API spec 7-2 standards. The connections on the 8” prototype joining these components with exception to the disconnect collets are standard API 6 5/8 API Reg or 6 5/8 Full Hole. The Disconnect collets have been designed to the strength limits expressed in typical Drilling Jar catalogues. Manufactured from tool steel for optimum durability. Presently the tool is limited to operations up to 150 deg c.

The motors operating both the circulation valve and the disconnect function are geared up to provide a mechanical advantage of approximately 20,000 to 1. The EC22HD+GP22HD Maxon motors are 22mm diameter and specifically designed for high temperatures. i.e. 2000 hours at 180c and operation in a fluid oil fluid environment. Although vibration test results on the motors are presently available to 17G the motors are securely housed (to remove strain on the mountings). Further testing at higher levels is being scheduled. Photos 1 and 2 show the motor testing. The motor supplier provides motors to the Aerospace industry as well as for Drilling applications. Figure 9 shows endurance reliability testing charts of the motors at 180 DegC and vibration levels up to 17G.

The present 8” tool is designed with an unobstructed through bore of 60mm to ensure ball drop or wire line tools can be deployed below it. All mechanisms are lubricated in a pressure compensated oil reservoir to reduce friction and ensure reliability. Electronics circuitry and batteries are housed in a sealed enclosure behind high temperature, high pressure bulkheads. The electronic monitoring sensors are recorded on the onboard memory microprocessor. On retrieval of the tool separated or whole this information can be extracted though a port on the side of the tool.



Photograph 1 and 2 showing electric Motor testing rigs.

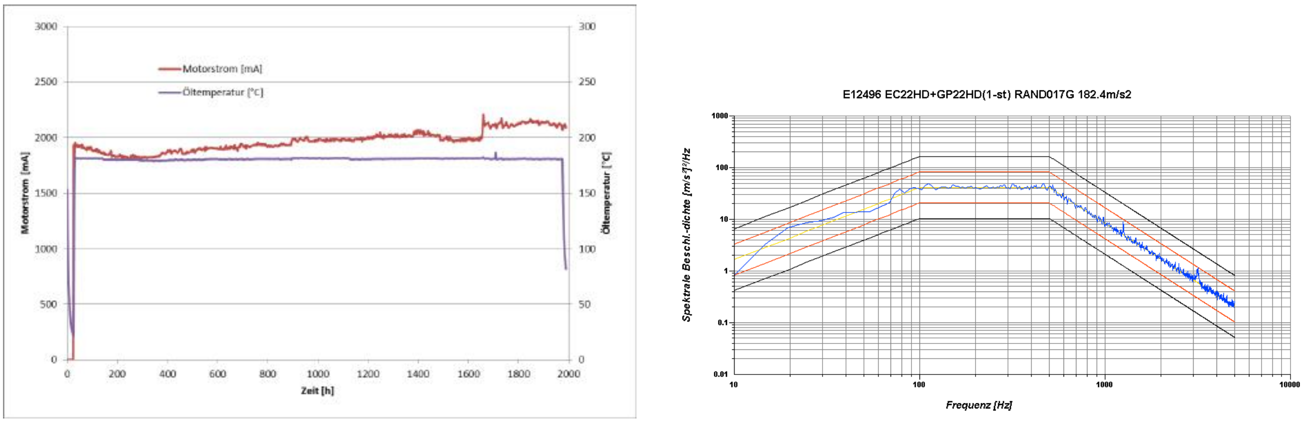


Figure 9 – Graphs of Motor reliability testing, 2000hrs operating at 180 degC at up to 17G vibration levels

Conclusion

It is clear that lost circulation and stuck pipe will continue to be major causes for concern and account for large NPT events. This is something that is becoming more influential as wells become more complex and difficult. The lack of a skilled workforce is also something that is recognized by the industry. It has already been shown that the use of high technology in complex wells can reduce the incidence of stuck pipe (Tollefson et al, 2008). The application of technology to improve wellbore clean up, mitigate lost circulation and reliably disconnect from the BHA, must be an area of focus to provide better performance in these areas. Having a reliable solution for these events already built into the BHA, allows the Operator to accurately build in to their contingency planning, the recovery timeline.

Acknowledgements

Maxon Motor UK ltd., Maxon House, Hogwood Lane, Finchampstead, Berkshire, RG40 4QW, United Kingdom for providing Motor test data and providing test facility.

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