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Disappearing Tubing Hanger Plug (DTHP) Improves Well Integrity and Saves Rig Time for Deepwater Well Completions

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Abstract

Traditionally, to complete a subsea well with a vertical Christmas tree, it is necessary to land the tubing hanger and install and pressure test a wireline set tubing hanger plug. Once the plug is tested, the subsea BOP can be removed, the vertical Christmas tree can be installed, and the plug retrieved through the work-over riser before the well is ready for production or injection. This is a time consuming rig operation requiring additional handling of the work-over riser and wireline run, which increases both the HSE and operational risks. With increasing focus being placed on the safety, reliability and cost efficiency of deepwater developments, it is critical that the operational risk and rig time for drilling and completions is reduced.

This paper describes the innovative invention of a shallow set barrier plug ï the Disappearing Tubing Hanger Plug (DTHP) ï and includes a case study of the first application of the plug on Akpo-214. This ground-breaking solution, based on knowledge of the existing glass barrier plug technology, was developed through a collaboration between Total E&P Nigeria and TCO. The objective of the invention is to provide a more reliable and cost effective solution for deepwater completions offshore of Nigeria.

The application of the DTHP has proven that the disappearing feature of the DTHP with pressure cycling is effective and reliable. The pressure cycle was applied directly from the FPSO, liberating the expensive rig for other purposes. The DTHP also provides improved well integrity by forming an ISO14310 V0 qualified gas-tight barrier. The operator saved rig time for the first installation and the rig time saving is estimated to be mutiple days for an optimized completin sequence on deepwater applications, which directly translates into savings of millions of USD.

Introduction

Discovered in the year 2000, Akpo is a gas and condensate field operated by Total. The Akpo field is located in the deep water region of Nigeria, with a water depth of approximately 1,400 metres. It is situated on Block OML 130, approximately 124 miles (200 kilometres) from Port Harcourt.

The Akpo field development project began in 2005 and includes 44 subsea wells with 22 producers, 20 water injectors and 2 gas injectors all tied-back to an FPSO. The subsea infrastructure consists of 110 kilometres of a complex array of high pressure and high temperature subsea flow lines connected by steel catenary risers to an FPSO.

Safety is always the top priority for all oil and gas companies, particularly when undertaking operations in deepwater or ultra-deepwater environments. Here, a failing well barrier element may lead to a catastrophic event, which may cause injuries and loss of life, pollute the environment, and result in major losses on the investment.

Upon completion of the Akpo development project, the field is expected to produce up to a total of 185,000 barrels per day which is the FPSO capacity.

Barrier philosophy ï Two barrier rule

Total E&P practices the ñtwo barrier ruleò in all subsea wells. A robust well completion design in line with the barrier philosophy is therefore the key to the success of each development. This rule applies not only during the well completion phase, but also throughout the lifecycle of the well. Having a second shallow set approved barrier in the well before performing a tubing hanger test, and nippling down the blowout preventor (BOP), is a part of this philosophy.
Using the surface-controlled subsurface safety valve (SCSSSV) as the second barrier is not considered an optimal solution, since it is not possible to perform a positive pressure test on the tubing of the SCSSSV as the secondary barrier.

Another factor is that neither the deep set isolation device (ball valve type) nor the SCSSSV is an ISO14310 V0 approved barrier. These products are only gas-tight, and therefore do not fulfil the ISO 14310 V0 requirements.
However, the Disappearing Tubing Hanger Plug (DTHP) is an ISO 14310 V0 approved barrier, which has the strictest acceptance criteria in the industry with zero leakage.

In accordance with the ISO 14310: 2008 Packers and Bridge Plugs requirements specification, in order to qualify for ISO 14310 V0 the test requirement acceptance criterion is ñgas test plus axial loads plus temperature cycling plus zero bubble.ò

Since the two barrier philosophy is a compulsory practice for Total, every well must have two independent barriers for the main bore and well annulus prior to the well being handed over to field operations (FPSO), or whenever the well is suspended. No exception is made for water injectors. Total E&P must comply with this philosophy by having two barriers in the completion string before hand over to FPSO for injectivity testing. This completion strategy saves rig time for the operator and is therefore more cost effective.

Since Akpo is a major project with many wells, the development of this field will be spread over many years. Total is therefore constantly on the lookout for new solutions that are safer and more efficient in terms of both time and cost.

The DTHP was implemented to ensure the difference between the two types of barrier. During the initial phase of the Akpo development, two identical formation isolation valves from the same manufacturer were used. This posed a potential issue, since the same factor may affect the two barriers at the same time. The DTHP solution was therefore introduced to ensure full compliance with company rules. Two completely different barriers were required in order to reduce the probability of losing control of the well due to a single event.

Christmas tree selection

Generally, there are two types of subsea Christmas tree available for subsea applications:

1. Vertical Christmas tree (conventional Christmas tree)
2. Horizontal Christmas tree

The main difference between the vertical Christmas tree and horizontal Christmas tree is that when using a vertical Christmas tree, the operator has to land the tubing hanger, remove the BOP and then set the vertical Christmas tree on top of the tubing hanger. A horizontal Christmas tree is landed during the wellhead construction phase before the completion operation, and the subsea tubing hanger is landed directly inside the horizontal Christmas tree during completion.

TOTAL has opted to use a vertical Christmas tree (conventional Christmas tree) for deepwater projects due to various reasons. The main advantage is the ability to remove the Christmas tree without interfering with the subsea tubing hanger. Due to the fact that the subsea tubing hanger is landed inside the horizontal Christmas tree during the completion phase, any repair work required on the horizontal Christmas tree will also result in the workover of the entire well, which involves unsetting the packer and pulling the tubing hanger with the upper completion before the horizontal Christmas tree can be removed.

The probability of having to recomplete the well is assessed as being far less likely than the probability of having to pull the Christmas tree, and so the conventional vertical Christmas tree is preferred. In addition, the production of subsea Christmas trees is usually a time-consuming process with long lead times before delivery. Because of this, another major benefit to using a vertical Christmas tree is that it can be installed at a later stage, after the well is completed. This is highly important in the project execution, since it provides the option to start drilling and completing at an earlier stage of the project, without having to wait for the delivery of the conventional vertical Christmas trees. On the contrary, if the operator uses a horizontal Christmas tree, the Christmas tree must be available before completion can commence, which may delay the execution of the project.

In the completion of deepwater subsea wells, most operators tend to choose vertical Christmas trees, either due to risk assessments or cost considerations, or simply due to lead times. This paper therefore focuses on wells completed with conventional vertical subsea Christmas trees, and all evaluations included in this paper are based on a design review and best practice for current applications using vertical subsea Christmas trees. The discussion will not be relevant to applications using horizontal Christmas trees.

However, the application of vertical Christmas trees also involves some limitations. If, depending on the barrier philosophy of the operator, it is necessary to set a back pressure valve (BPV) inside the tubing hanger before removing the BOP, the vertical Christmas tree must be deployed using a work-over riser so that the BPV can be retrieved after the Christmas tree has been installed. Though possible, this operation has proven to be time-consuming and risky, since it involves heavy lifts and major logistical challenges, and also requires a good weather window for safe execution.

With the increasing water depths of the latest developments, the deployment of vertical Christmas trees on work-over risers has become very expensive, and an alternative solution was desired.

DTHP barrier features, design and qualification

In October 2011, Total contacted TCO regarding the possibility to qualify the DTHP for use in water injectors on the Akpo field in Nigeria. In December 2011, design criteria and a development schedule were created for the construction of the prototype and qualification of the DTHP in accordance with the test criteria, in order to have four plugs ready for delivery by September 2012.

The companies agreed to start the development project together and agreed upon the features and qualification requirements for the plug. The plug project was finally approved at third party testing facilities at the International Research Institute of Stavanger (IRIS) in Norway on 15 June 2012.

The key features of the DTHP were adopted from the existing Tubing Disappearing Plug (TDP) technology, which is typically used as a deep set barrier. With the addition of bypass channels and a bypass sleeve, TCO designed a shallow set secondary barrier for subsea applications. The TDP has a proven track record for Total in West Africa, with several successful installations. However, since this plug is run in a pre-set configuration, a bypass function had to be added in order to make it suitable as a shallow set barrier. The bypass is necessary in order to pressure up the entire tubing string to set the packer and perform the tubing test prior to closing the shallow set plug. Another challenge was to make the design slim enough to be run inside the 10¾ò casing, preferably concentric, and with a good clamp design to protect the control lines passing on the outside of the assembly. Since the plug was to be run as part of the upper completion above the production packer, the assembly needed to have only premium connections. Since the DTHP would be run just below the tubing hanger, the design had to be strong enough to handle the weight from the load of the tubing below it.

In principle, the basic concept of the remotely operated TDP consists of the following main components as shown in *Figure 1*:

1. The carrier sub, which is run as part of the completion string
2. The glass package, which works as an internal barrier plug within the carrier sub
3. The explosives charges, which pulverize the glass once activated
4. The cycling device, which activates the explosives charge by recognising pressure pulses from the surface

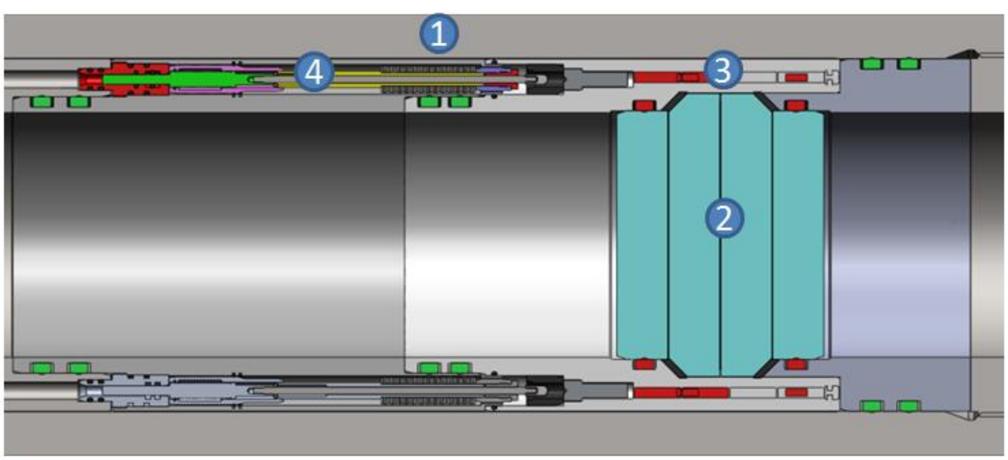


Figure 1: Tubing Disappearing Plug concept

After the final design review, both companies agreed upon a concept that was acceptable for the application and fulfilled the test criteria to qualify the new shallow set barrier plug design. The concept for the shallow set plug was the same as for the deep set plug, but with the addition of the bypass channels and bypass sleeve. This is shown in *Figure 2*.

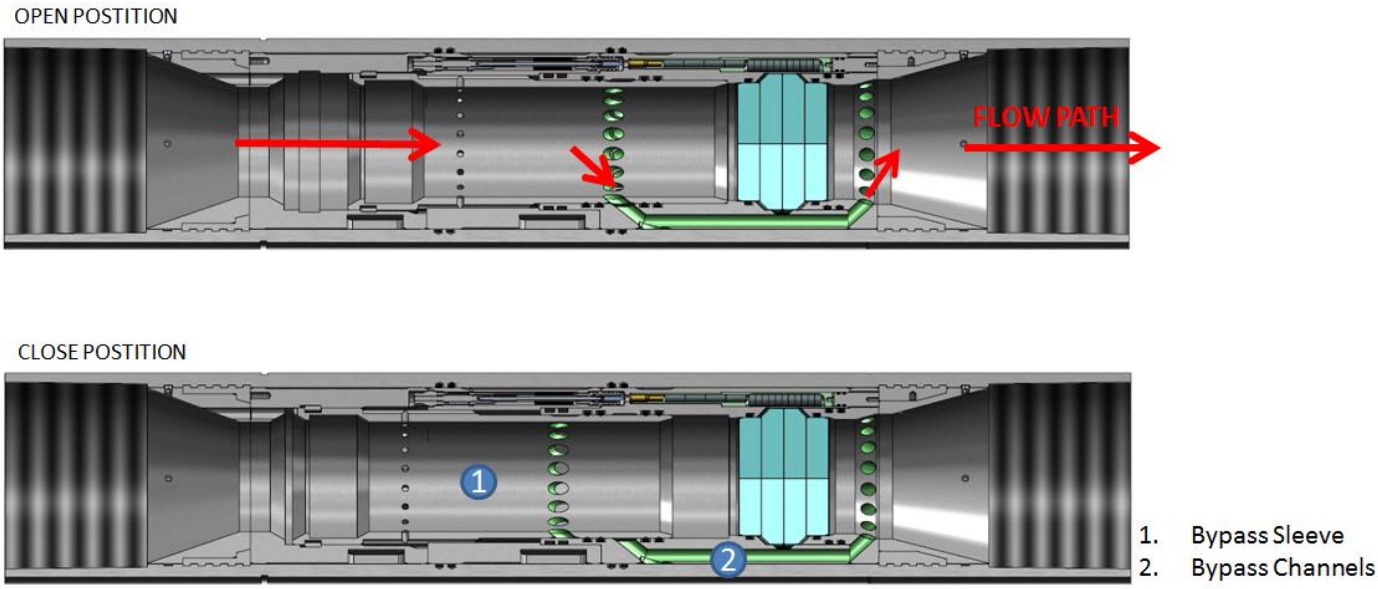


Figure 2: Tubing Disappearing Plug in open and closed position

Some of the test criteria specified for the development project:

- Assembly maximum outer diameter : 8.81ò
- Assembly minimum inner diameter : 4.75 ò
- ISO 14310 validation : V0 qualified
- Minimum flow rate through bypass : 500 l/min
- Total flow volume : 100,000 litres
- Closing method for bypass : Wireline shifting tool upwards shifting

The plug was qualified to the highest possible standard of ISO 14310 V0, and the bypass channels were tested to the required flow rate and flow volume to ensure that the plug would allow the required circulation flow rate without damaging the bypass channels. After the flow test was performed with the specified flow rate and total flow volume, the plug was pressure tested ok. After the flow test (see *Appendix D-2* for results), the DTHP was disassembled and the bypass ring, closing sleeve and glass support ring were photographed to document any washout or visible abrasion from the flow. *Appendix D-1* shows the images from the investigation that formed part of the Internal Full Scale Test Report.

Conventional completion sequence

Conventionally, when a vertical Christmas tree is used for a deepwater completion, an additional plug must be run in order to perform a tubing hanger pressure test. Running a conventional wireline set plug necessitates the running of a work-over riser in order to retrieve the plug prior to production or injection.
Another option considered by Total was to run an isolation device (ball valve type) in the upper completion. However, this was not considered an optimal solution since a V0 barrier and two different barrier types that would reduce the probability of losing control of the well due to a single event were required.

Case study Akpo-214

The Akpo-214 well was a new injector well completed in July 2013. It was drilled in the middle and lower reservoir to achieve an injection rate of 13,000 BPD to support a nearby oil producer.

The well was completed with a lower completion consisting of stand-alone screens and a formation isolation valve (FIV). The upper completion consisted of:

- 9ę ò x 5½ò injection packer
- 5½ò gauge mandrel
- Integrity injection valve (IIV)
- DTHP with bypass sleeve and circulation ports

The upper completion was run in hole on 15 July 2013. The well was drilled and completed in 64.4 days, of which 23 days were used to install the completion. There were some issues that contributed to NPT, including two unintentional closures of the IIV, and a total of five attempts to close the DTHP bypass sleeve with the shifting tool.
NPT for running the upper completion was largely due to the following events:

- Upper completion POOH due to IIV flapper valve closing unintentionally on two occasions (60.75 hours)
- Five runs to close the plug bypass sleeve (11.5 hours)

The root cause of the additional runs in order to close the bypass sleeve was inconclusive. However, it was evident that the amount of pipe compound used for the WOR was excessive. The After Action Review (AAR) of the project suggested some improvements for future runs:

- Limit the amount of work-over riser (WOR) dope applied
- Optimise the slick line BHA and procedures (see *Appendix D-3*)

Once the DTHP bypass sleeve was closed, the shallow set barrier was tested and the BOP finally nippled down. The Christmas tree was installed and the plugs cycled open from the FPSO in order to prepare the well for injection. At this point, the shallow set DTHP had seven remaining pressure cycles, since three cycles had already been performed. The formation isolation valve (FIV) in the lower completion had three remaining cycles, since seven cycles had already been performed.

Figure 3 shows the pressure cycling sequence used to cycle open the DTHP and FIV from the FPSO. The DTHP cycled open after seven pressure cycles from the FPSO as planned. After the seventh cycle, the Christmas tree pressure equalised with the pressure in the well, which is a clear indication of communication between the Christmas tree and the downhole gauge. It was therefore conclusive that the shallow set barrier plug had been removed.

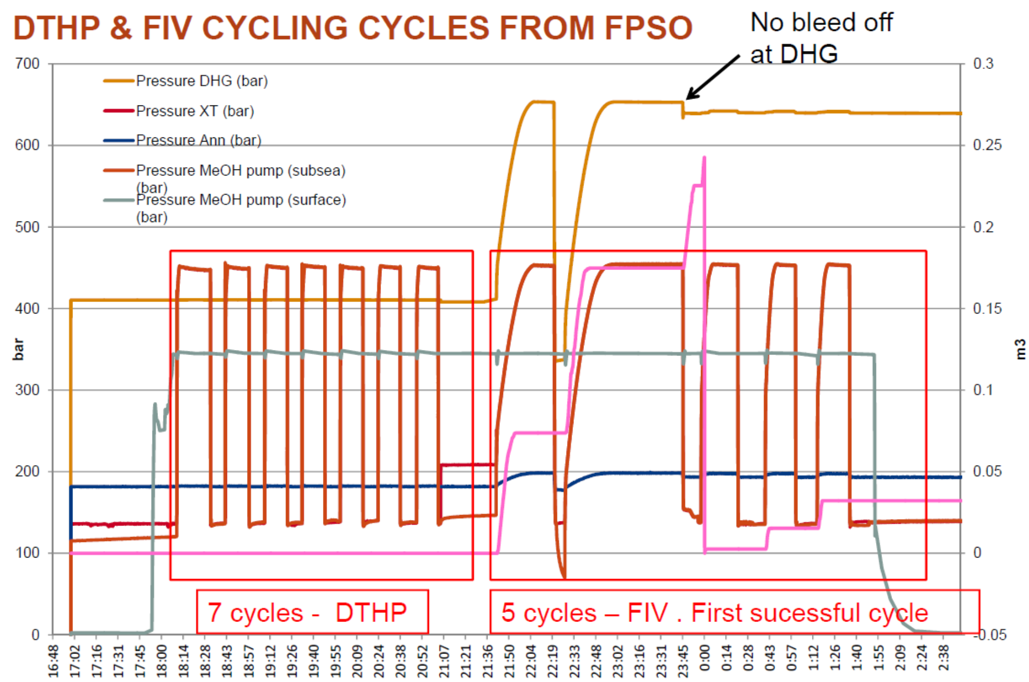


Figure 3: Cycle open sequence of DTHP and FIV

11 pressure cycles were performed to cycle open the FIV. No changes were seen on the downhole gauge. It was suspected that debris accumulation on top of the IIV closed the valve and obstructed pressure transmission to the FIV. The subsequent sequence was therefore:

- Retrieve the IIV choke
- Temporarily lock open IIV
- Cycle open FIV (remaining two cycles)
- Reinsert IIV choke
- Perform mini injectivity test and inflow test IIV

This additional operation sequence took the operator 15.5 days. A total of 1.4 litres of debris was recovered from the well as shown in *Figure 4*. The recovered debris had the following content:

- Glass particles 11.3%
- Clay-like particles 88.7%

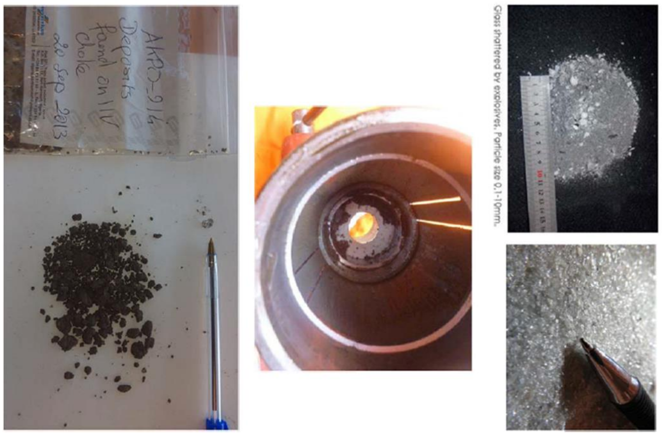


Figure 4: Debris recovered from Akpo-214

The final well status showed an injection rate of 12,600 BPD, which was very close to the target of 13,000 BPD. The impact upon the nearby producer has not yet been evaluated.

Rig time saving comparison

Since this was the first DTHP field application, the well programme was not optimised to gain the most benefit from the DTHP technology. The main objective of this DTHP application was to test and prove the designôs effectiveness, and to observe best practices.

In order to ensure easy recovery if anything should not go according to plan, the operator still deployed the subsea Christmas tree by using a work-over riser in the conventional manner. This operation was time-consuming and involved major logistical challenges and heavy lifts. In an ideal situation, the Christmas tree would have been deployed using a light intervention vessel (LIV), liberating the rig for other uses and therefore reducing rig time. A more efficient subsea Christmas tree deployment method would have differentiated the DTHP technology from the conventional completion methodology.

Depending on the geographical area, climate and sea conditions can be rough at times, resulting in delays to heavy lifting operations offshore and incurring days of ñwait on weatherò (WOW) NPT.

Table 1 provides a comparison of the time taken to complete one water injection well with a vertical Christmas tree at a water depth of approximately 1,300m, as is the case for the Akpo field in Nigeria, using different completion methods. WOW considerations are not taken into account in this comparison.

	Estimated Rig Time, hours		
Operations	**Conventional Method without DTHP**	**AKPO-214**	**Ideal Case with DTHP Application**
Set Packer	6	6	6
Tubing Pressure Test	2	2	2
Perform all other required pressure / function tests	5	5	5
Set WL set plug	4	Not Applicable	Not Applicable
Close Bypass Sleeve with Shifting Tool	Not Applicable	3	3
Tubing Hanger Pressure Test	2	2	2
Pull WOR	11	11	11
Remove BOP	13	13	13
Install Xmas Tree by WOR / LIV	36	36	0
Retrive WL set plug	4	Not Applicable	Not Applicable
Pull WOR	11	Not Applicable	Not Applicable
Connect Prod.Riser to FPSO (zero rig time)	0	0	0
Cycle Open DTHP from FPSO / Vessel (zero rig time)	0	0	0
Cycle Open Deep set Plug	0	0	0
Start Injection	0	0	0
Estimated Total Time	94	78	42
Estimated Time Saving		16	52

Table 1: Rig time saving comparison for various completion sequences

As shown in the estimated time saving comparison for Akpo-214, in theory the time saving should have been approximately 16 hours for the chosen completion sequence. The fact that there was some NPT associated with the problems of closing the bypass sleeve only gave a net time saving of 4.6 hours for the first field application.

If the BHA is improved for shifting the bypass sleeve, or the sleeve is alternatively closed remotely, the rig time saving is estimated to be over 16 hours. Having a remotely operated shallow set barrier plug also gives the operator greater flexibility, and one option is to run the Christmas tree from the boat instead of utilizing the rig for this operation. As the estimate in *Table 1* shows, this approach would save the operator approximately 2.2 rig days (52 hours) at a water depth of approximately 1,300 metres, not taking WOW into consideration.

This paper has not taken wait on weather considerations into account, which may lengthen the completion time drastically for some areas of the world. The estimated rig time saving will therefore obviously increase further when this is applied for deeper waters.

Conclusion

The DTHP was successfully qualified in compliance with the operatorôs requirements and passed the highest oilfield standards for barrier plugs. The DTHP was deployed in a deepwater well on Totalôs Akpo field in Nigeria, and was successfully opened by pressure cycling from the FPSO. This liberated the rig for other uses and has proven to save time and money for the operator. The estimated rig time saving for a subsea well with this configuration has been estimated to be over two rig days if the Christmas tree is run from an LIV. This estimated time saving applies to subsea wells with a water depth of approximately 1,300 metres, and does not take WOW into consideration. When taking WOW into consideration and/or estimating the time saved for wells at greater water depths, the rig time saving will increase further.

Even though there were some problems with the shifting of the bypass sleeve for the first installation of the DTHP, the slick line BHA has been optimised in order to prevent this from recurring.
It has been proven that the residue from the DTHP is minimal and poses no threat to the operation of other tools in the well.

Appendix D ï Sample figures

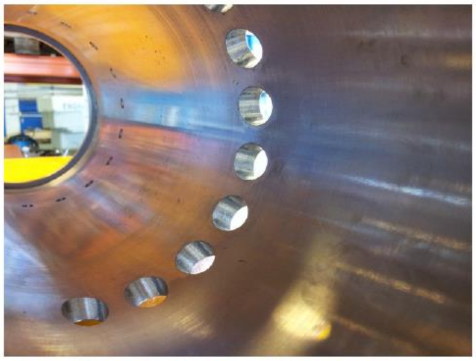


Figure 20: The inside of the Closing Sleeve before flow test.

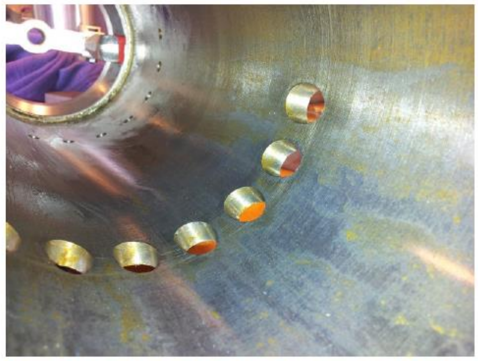


Figure 21: The inside of the Closing Sleeve post-flow test.

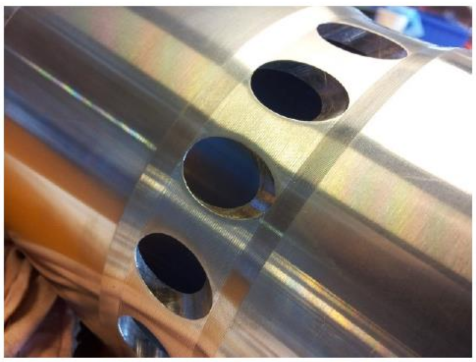
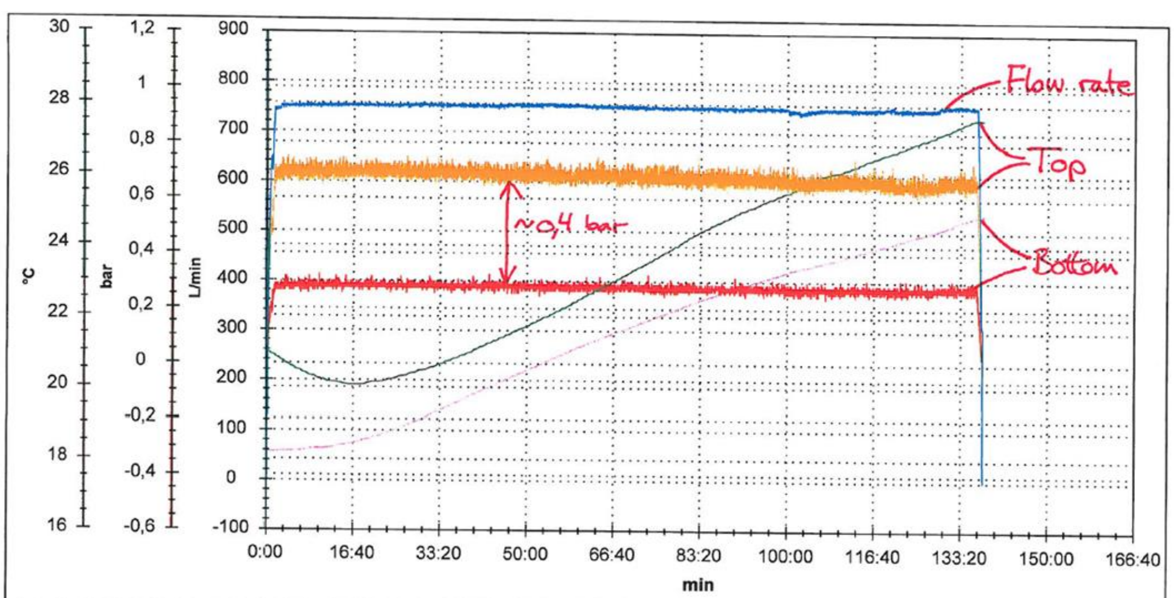


Figure 22: The outside of the Closing Sleeve before flow test.

Figure 23: The outside of the Closing Sleeve post-flow test.

Appendix D-1: Photos of inside and outside of closing sleeve after in-house full scale function test.

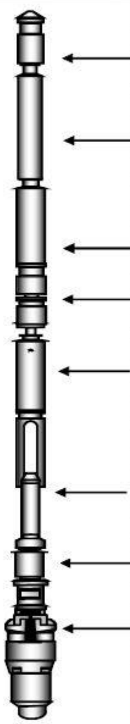


Legend 05.06.2012 11:01:57											
Measuring name (title)				Datail legend							
Channel	Input	Name	View	Unit	Visible	Channel	Input	Name	View	Unit	Visible
A1	IN1		ACT	L/min	Yes	A2	IN2		ACT	bar	Yes
A3	IN2T		ACT	°C	Yes	A4	IN3		ACT	bar	Yes
A5	IN3T		ACT	°C	Yes						

Appendix D-2: Results from DTHP full scale test report flow test

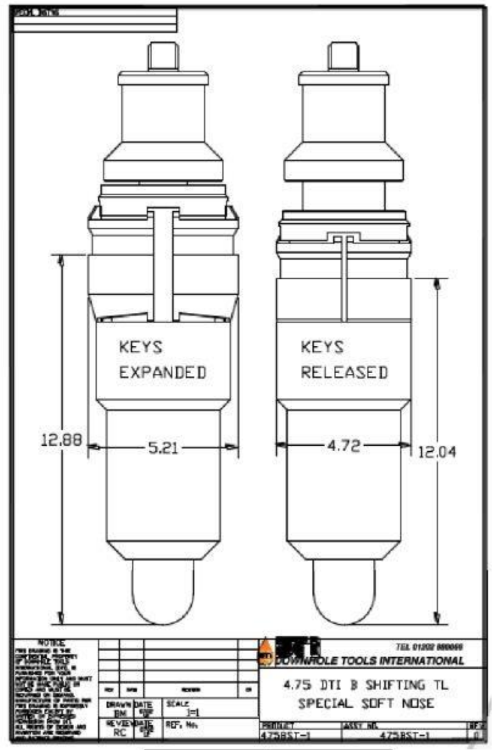
SLICK LINE BHA & "B" SHIFTING TOOL

Installation:	Well No.	
Type of Wire: **0.125" Slickline**	Well Type: Injector	
Operation Details: Shifting closed the TCO Sleeve		



Length (Inch)	HDQRJ/S.R	Description	O.D. (in)	F/NECK (in)
10	2.5" HDQRJ	ROPE SOCKET	2.5"	2.312"
60	2.5" HDQRJ	5ft STEM BAR	2.5"	2.312"
36	2.5" HDQRJ	3ft STEM BAR	2.5"	2.312"
17	2.5" HDQRJ	SWIVEL JOINT	2.5"	2.312"
42	2.5" HDQRJ	HYDRO MECHANICAL JAR	2.5"	2.312"
84	2.5" HDQRJ	SPANG JAR *30" Stroke* Open	2.5"	2.312"
7.5	2.5" HDQRJ	X-Over *2.5" HDQRJ Pin x 1 1/16" SR Box*	2.5"	2.312"
17.5	1-1/16" SR	TCO - B SHIFTING TOOL (4.720" O.D Keys retracted) (5.200" O.D Keys expanded) (1 Brass Shear Pin)	**4.720"**	3.12"
		CLOSE SLEEVE POSITION		
		JAR UP		
Length ft	22.8	**Maximum Tool O.D.**	**4.720"**	

Total Company Man Signature: Date:



ASSEMBLY No	475BST-1
SERVICE	STD
OD KEYS EXPANDED	5.20"
OD KEYS RETRACTED	4.73"
KEYS WILL PASS	4.75"
SHEAR PIN	1 X 3/8" MS
SHEAR PIN STRENGTH	12,811 LBS BREAK
M/U LENGTH	19.4"
TOP CONNECTION	1 1/16-10 UN PIN
BOTTOM CONNECTION	SOFT NOSE
FISH NECK	3.125"
TENSILE STRENGTH	68k LBS

Appendix D-3: Revised BHA for shifting tool to close DTHP bypass sleeve