Experiences from TTA including presence of gauge cables

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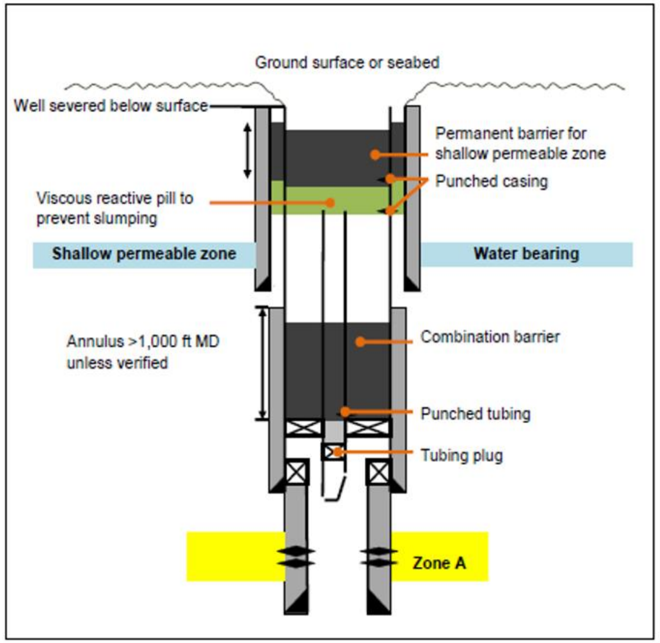
Agenda

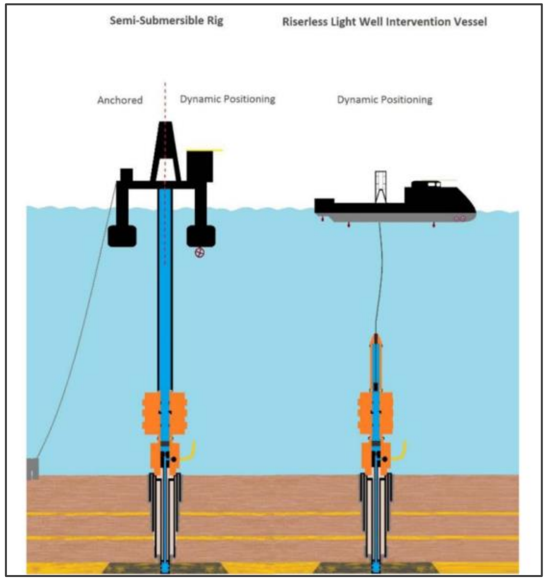
- Overview of project
- Evaluation & design process for TTA
- Evaluation of risks associated with gauge cables penetrating barrier
- Project execution & learnings
- Future work

Through Tubing Abandonments (TTA)

- Not a new concept, employed for many years
- Completion components left downhole & cement spotted via production tubing
  - Bull headed across production liner
  - Circulated into place across tubing ID and A-annulus
- Rock to rock seal requires sufficient annular barrier in casing annulus

- Benefits
  - Can be done rig-less
  - Simpler, quicker, cheaper
  - Reduced HSE exposure
    - Recover less hardware = less lifts at surface
    - Reduced waste to process at surface



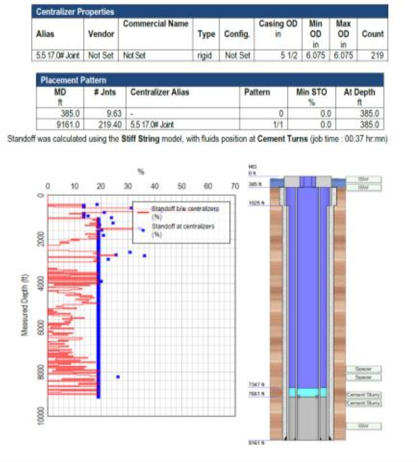


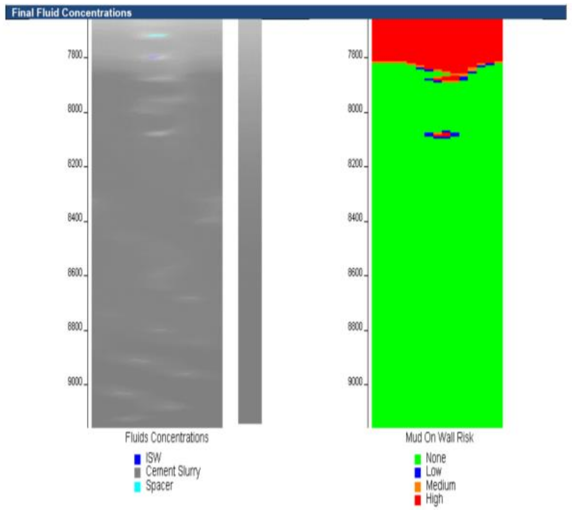
Project Overview

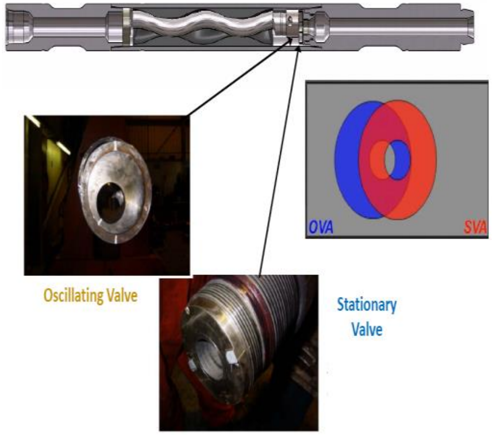
- 4 subsea wells to be plugged and abandoned
- All drilled between 1997 and 2007
- Initially planned from the rig
- TTA feasibility screening confirmed all wells as through-tubing abandonment candidates
- TTA scope switched to LWIV

Issue		Yes	Maybe	No
Abandonment Horizon Window				
Is the packer at least 100ft (for single barrier) or 200ft (for dual barrier) below the abandonment horizon?		> 200 ft below abandonment horizon for dual barrier	> 100 ft below abandonment horizon	< 100 ft below abandonment horizon not suitable for single barrier
Does the annulus cement have confirmed isolation below the abandonment horizon?		Logged good annulus cement/squeezing formation Modelled post-job good cement with no concerns	Uncertain cement quality, but mitigation available Flow potential modelling shows low consequence or Perf & Test data	Major losses
Will the isolations be laterally aligned (cap rock / annulus isolation / internal isolation)?		Yes		No
Completion				
Is there a gauge cable across the isolation interval? Has a risk assessment been completed to allow the gauge cable to form part of the barrier?		Mandrel > 200 ft above packer for dual barrier	Mandrel > 100 ft above packer	Mandrel < 100 ft above packer not suitable for single barrier
Is there a chemical injection line across the isolation interval? Has a risk assess… line to form part…		Mandrel > 200 ft above packer	Mandrel > 100 ft above	Mandrel < 100 ft above

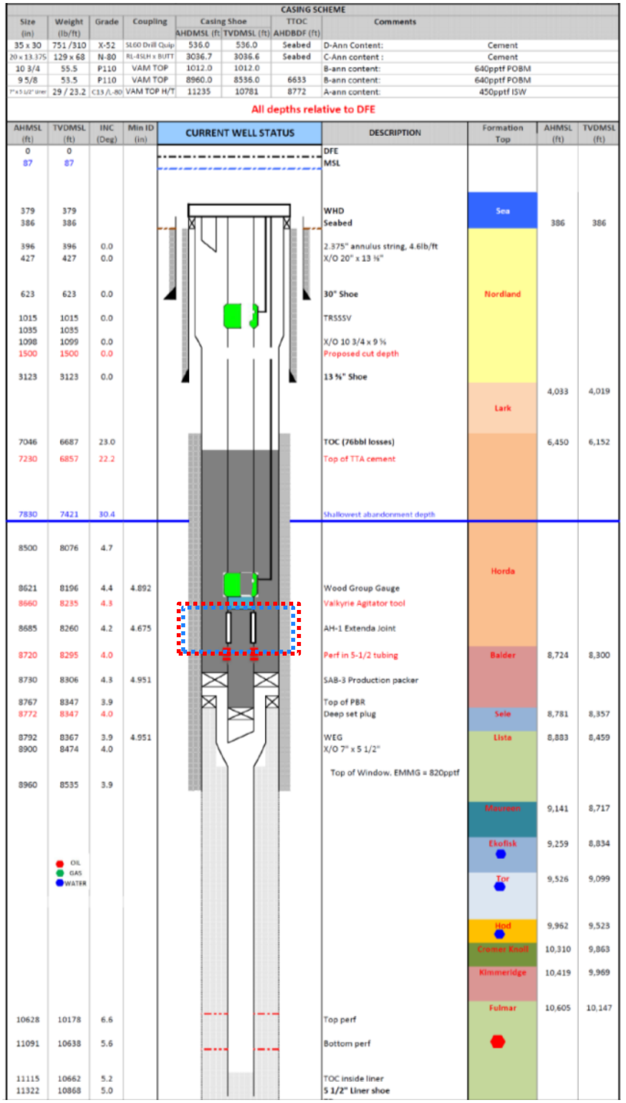
Issue		Yes	Maybe	No
TTA Execution				
Are there any scale risks / access issues that would prevent the setting of an agitator tool or reliable cement plug base?		No		Yes
How reliable is the planned cement plug base (deep set plug etc.)? Can it be monitored after being set?		No issues	Risk of failure	Unreliable (fails often)
Does the through tubing cement modelling show good cement across the isolation interval? Is an agitator tool required for cement placement?		Inclination < 30 deg at packer Modelling of internal cement plug indicates good cement across isolation interval. Mitigations in place to ensure high confidence of good cement placement.	Inclination > 30 deg at packer	
Is the sump volume <5% cement volume?		Yes		No
Will the tubing Integrity (including gas lift valves etc.) allow for a successful through tubing cement job?		Last WIT OK – no leak		No tubing / leak
Are there any other integrity issues (annulus pressures) that would compromise through tubing operations?		No issues	Any other WI issues	Sustained annulus pressure
General				
Has the proposed through tubing plan been accepted by the Regulator?		Yes		No
Risk Based Approach is Acceptable for specific well		Yes		No

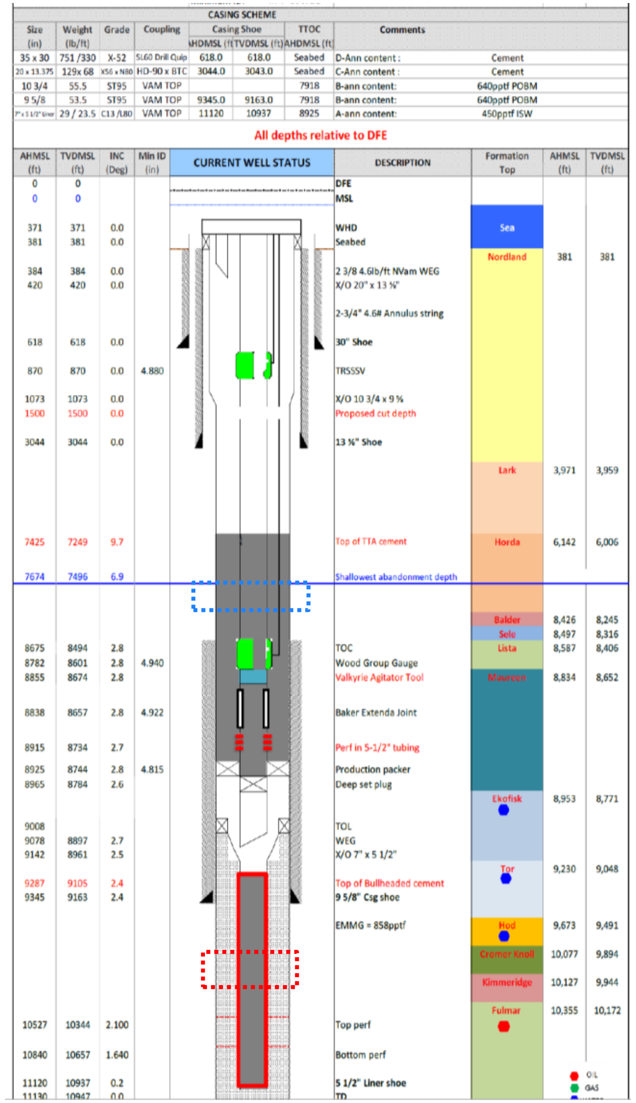


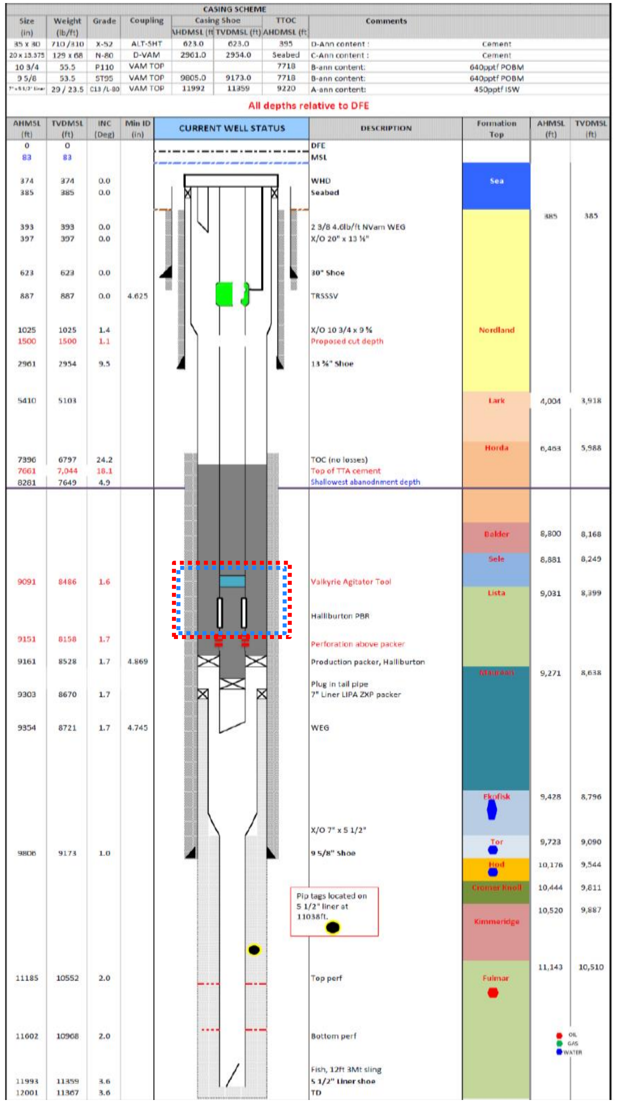


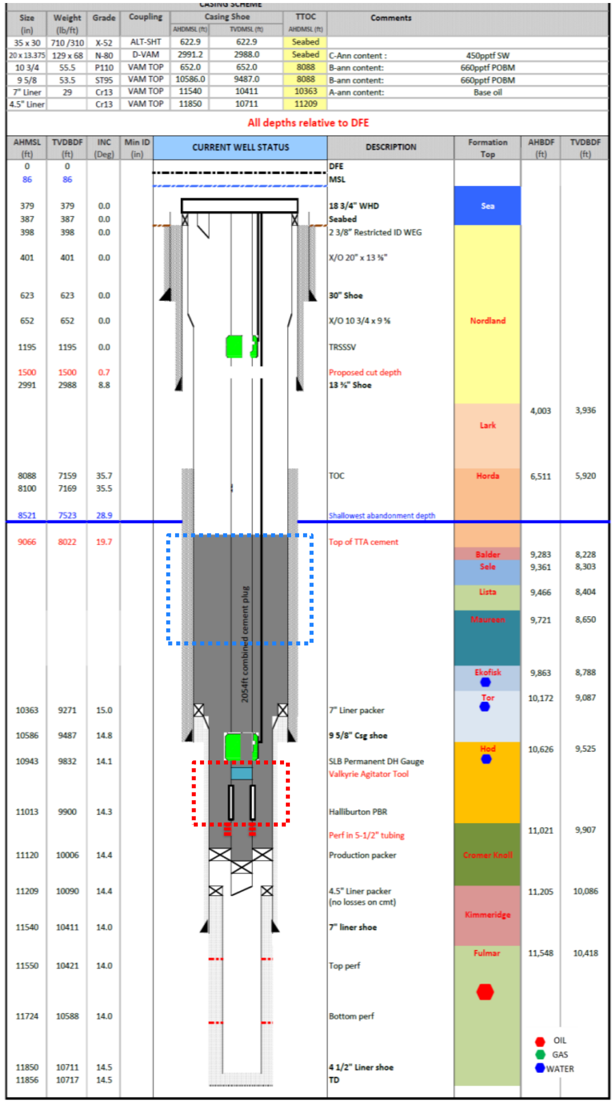


Wells Overview









Reservoir Barrier

Chalk Barrier

Are TTA with Gauge Cable Acceptable?

- OEUK Well Decommissioning Guidelines (Issue 6, June 2018)

3.6.1 Through-tubing Decommissionings

When well completion tubulars are left in hole and permanent barriers are installed through and around the tubulars, reliable methods and procedures to install these barriers should be established.
See figure 12 as an example of Through-Tubing Cased Hole Decommissioning.

Allowances should be made for:

- Cement slumping
- Channelling
- Lack of centralisation
- Small radial clearances
- Tubing integrity
- Full annular coverage
- Contamination
- Tubing debris, such as wax and scale
- Cables and control lines
- Modelling.

3.6.2 Penetrations Through Permanent Barriers

Provided the isolations outlined in these guidelines are achieved, cables and control lines can form part of permanent barriers. Assessment of potential leak paths and the plugging thereof should be conducted. A rigorous risk assessment process should be followed and documented and should consider:

- Penetration type e.g. ESP cable, gauge cable, chemical injection line, control line.
- Potential leak paths e.g. encapsulation, cable material, hydraulic line, bonding of barrier material.
- Encapsulation material e.g. plastic type, damage during installation, interfaces between materials.
- Degradation e.g. plastic encapsulation shrinkage, metal corrosion, barrier material interface, with consideration of temperature and fluid environment.
- Leak path failure modes, and well specific risk profile, which may include cross-flow modelling.
- Alternative isolation material requirements including seal-healing properties.

- Shell Well Abandonment Manual (WS 38.80.31.35-Gen, Revision 1.2, Oct. 1st 2021)

4.4.8 Control lines, cables and gauge lines through the isolation

When control lines, gauge cables or chemical injection lines form part of a permanent isolation, it **shall** be demonstrated that the leakage risk is ALARP.

Qualification of leakage risk with gauge cable

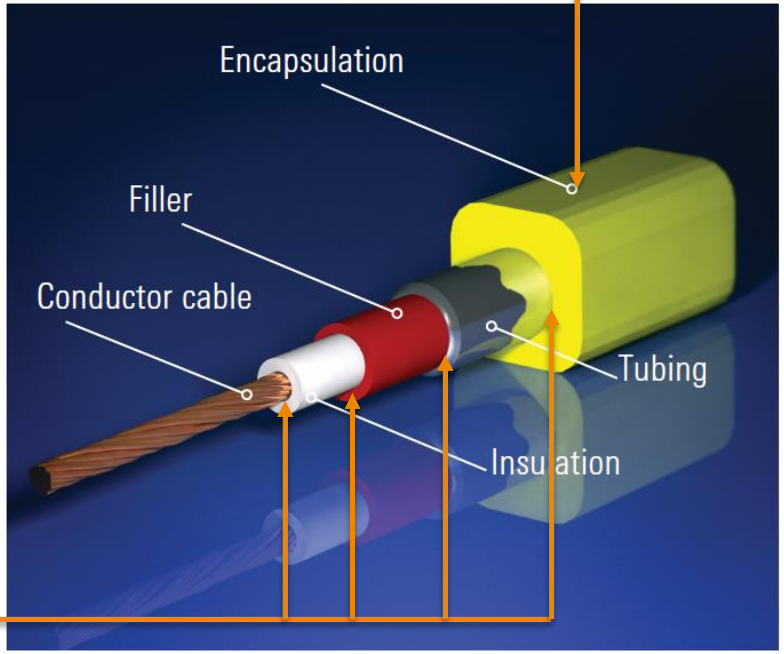
Primary Barrier Mitigations

Chalk Group

Cement Sealing Tests
- Evaluate sealing performance of cements in TTA configuration with gauge cable present
- Understand how cement design could be optimised to reduce risk of leakage

Accelerated Degradation Trials
- How can we expect the gauge cable encapsulation to behave over time?
- What level of degradation do we expect?

Internal Interfaces
- Understand the level of flow expected through the interfaces between the gauge cable's internal components



Cable External Encapsulation Degradation

- A study was performed by TNO on behalf of Shell to investigate the long term properties of Nylon cable encapsulations at high temperature & high pH conditions.
- A number of parameters were investigated to determine how they changed under simulated downhole environment.
- Experiments were performed at T = 80, 100, 120, 140, 160 °C and TTS was used to understand the behaviour of Nylon at lower temperatures over a longer timeframe.

Properties for sealing

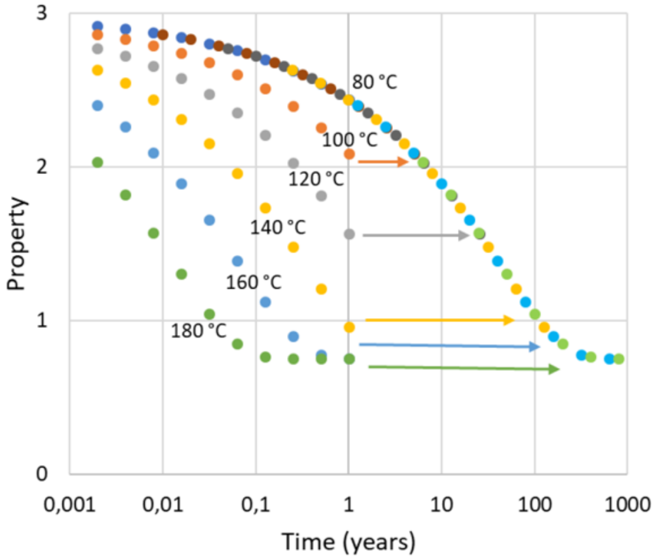
Volume of Polymer
Decrease in volume results in lower resistance against delamination of cable and cement

Strength
Decrease in strength results in lower resistance against deformation by cement

Property	Infers	Test Method
Density Change	Change in volume	Liquid immersion cell on an analytical balance
Melting point and Glass Transition Temperature	Change in crystallinity	Differential Scanning Calorimeter (DSC)
Weight in wet and dry conditions	Mass Change	Mass Balance
Hardness Test	Strength	Micro-indenter with Vickers diamond tip
Bending strength and modulus	Strength	Three point bending test on a tensile machine
Chemical composition	Hydrolysis & Depolymerisation of encapsulation in an alkaline fluid	Infrared Spectroscopy

TIME-TEMPERATURE SUPERPOSITION (TTS)

- Accelerated aging experiments at high temperature can be converted to longer ageing times at lower temperatures by TTS: $t_{TTS} = \kappa(T) \times t_{REAL}$; $\kappa(T)$ is shift factor and is temperature dependent



Leakage Through Cable Interfaces

- When a 5 bar dP (N_2) is applied over a cable (with a length of only 40cm) a leak rate of ~80ml/min was observed at room temperature.
- This leak is observed to come from within the "welded armor" as well as on the outside of the welded armor (interface with encapsulation).
- Upon increasing the temperature, the leak change mainly came from the material within the "welded armor".
- An increase in temperature greatly inhibited the flow seen, due to the expansion of the polymer materials.
- At downhole conditions we expect flow through internal interfaces to be even more restricted.

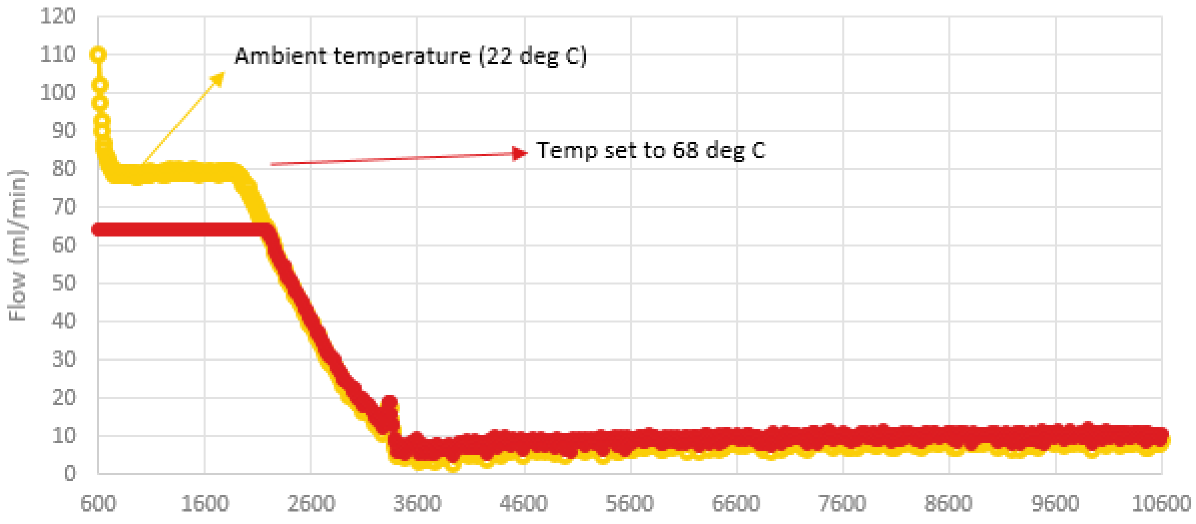
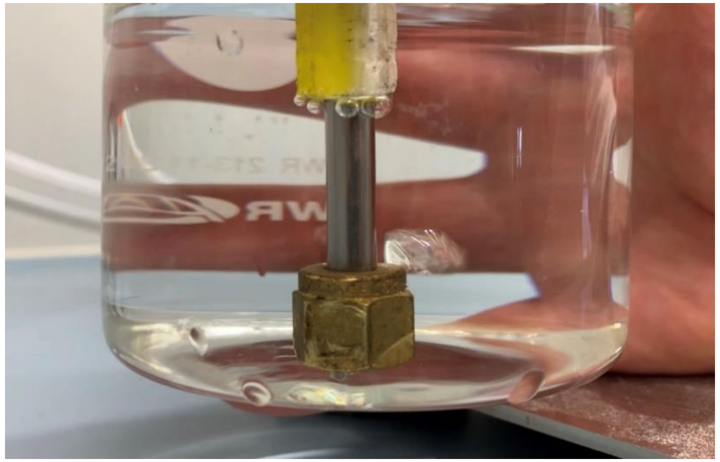


Figure 2: initial leak test, temperature effects



Cement Sealing with Gauge Cable - Test Apparatus

- Small & large scale test cells allow cement to be cured at downhole conditions (up to 100bar N_2/165C) whilst monitoring temperature & expansion pressure build-up at cement/steel interface.
- After curing the sealing ability is assessed by imposing a pressure differential and measuring leakage rate.
- Strong correlation seen in all testing between expansion pressure build-up and plugs sealing ability.
- Cell modified to allow testing with inner tubing and gauge cable.

Figure 16: Modified 8 inch dual casing set-up (open)

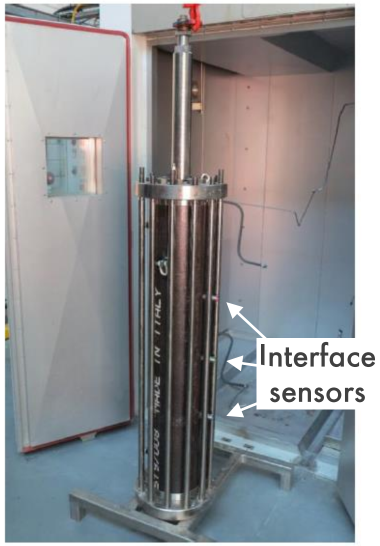
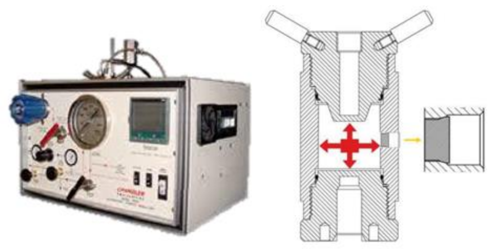


Figure 17: Closed 8" tester in front of oven

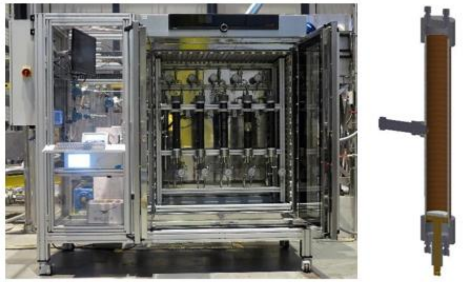
STCA Sealing performance evaluation equipment



Adapted UCA vessel

Evaluating plug material in adapted UCA vessel (for field)

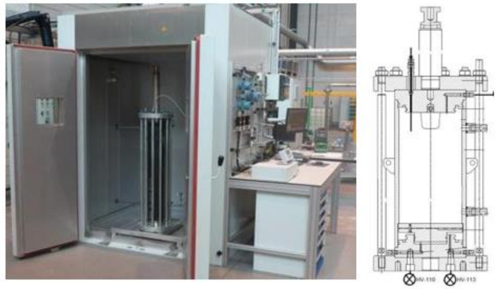
- 2.5" Plug, 0.08m length
- Slurry volume 0.25liter
- Setup time 0.5day
- No sealing test



Mini P&A tester

Evaluating plug material in small scale allowing rapid screening

- 2" Plug, 0.30m length
- Slurry volume 0.6liter
- Setup time 1day
- Yes, sealing test

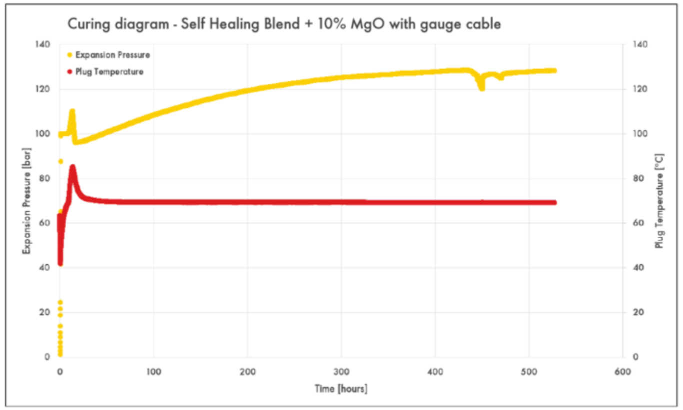


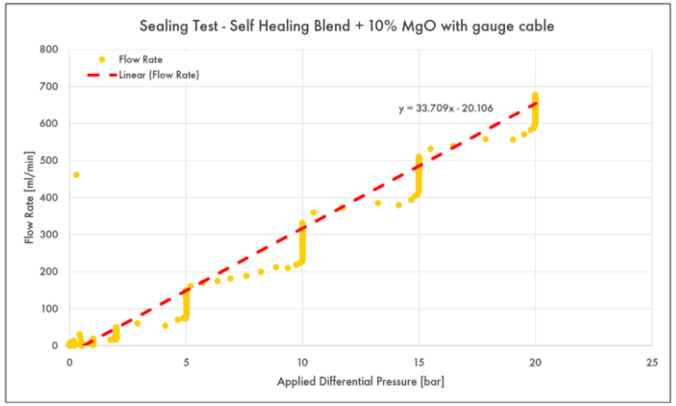
Large Scale P&A tester

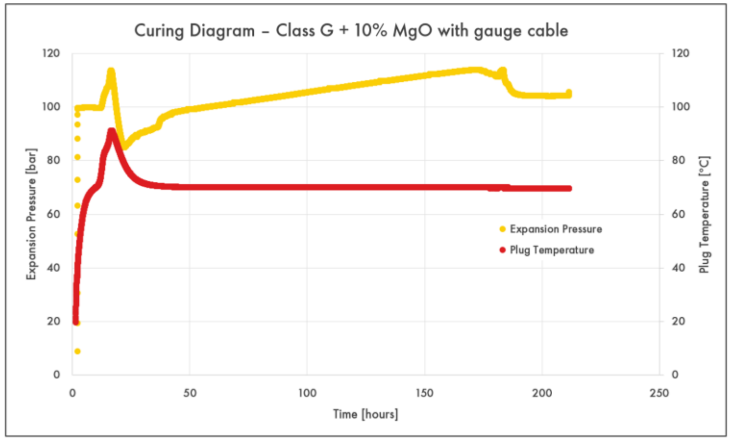
Large scale evaluation of selected slurries/solutions (scale matters)

- 8" Plug, 1.00m length
- Slurry volume 40liter
- Setup time 1week
- Yes, sealing test

Cement Sealing with Gauge Cable – Large Scale Test Results







- Test 1 shows relatively high seepage rate.
  - Design is typical of the industry standard expansive cement plug design.
  - Given possible limitations with testing (e.g. scale effects on length, no external constraint outside of casing, clean nitrogen) should not be considered a pass/fail but instead used to benchmark and compare to find optimum design.
- Min target for sealant across gauge cable was set at equivalent or lower seepage than test 1.
  - Both tests 3 & 4 met this.
- Based on available test data decision made to use self healing cement blend + 10% MgO for two wells where gauge cable penetrated barrier
  - Lowest seepage rate of tests with gauge cable
  - Lower seepage rate than conventional class G slurry without gauge cable (test 1)
  - Secondary benefit of self healing component which would swell on contact with hydrocarbons if gauge cable encapsulation degraded

Test	Cement Recipe	Gauge Cable Present?	Expansion build-up rate (hr/bar)	Expansion pressure at start of sealing test (bar)	Seepage rate (ml/min/bar)
1	Class G + 4% MgO	No	133	0.5	572
2	Class G + 10% MgO	No	7.8	13	4.4
3	Class G + 10% MgO	Yes	8.1	13.6	457
4	Self Healing + 10% MgO	Yes	6.3	29.9	33.7
5	Repeat of test 3 (Curing extended – post project execution)	Yes	6.4	39.6	36.3

Outcome & Learnings

- All four TTA cement plugs successfully placed
  - Class G + MgO cement used on two wells without gauge cable
  - Self healing + MgO used on two wells with gauge cable
- Three verified as suitable barriers with pressure test and verification checklist
- Issues seen on one well #3 - no gauge cable present in this well

Subsea LWI - P&A Through Tubing Abandonment (TTA) Verification Checklist

Well :
Date :
Cement Plug Details (Plug # / Barrier):

Planning Requirements (Completed during pre-job meeting)	Parameters	
Activity	Criteria	Actual
Cement plug will be pumped as per recipe approved by Shell PC Lab for use with Non-Tag Method?	Yes	
Lab test(s) confirmed with rig cement and additives[1]	Yes	
Cement barrier length is aligned with the latest version of the Well Abandonment Manual UK Supplement?	Yes	
Tubing suitably sized to allow efficient fluid displacement and cement placement (Reference cement vendor simulation)	Yes	
Pipe movement required for all through tubing cement jobs (Use of NOV Agitator tool)	Yes	
Plug to be set on a competent base? The base shall be weight and/or pressure tested [2]. **Note:** Cement is typically placed as close as possible to the production packer so this can provide a base for the cement in the A annulus. A deep-set plug in the tubing will provide a base inside the completion tubing stump. Sump lengths between tubing cut and these bases should be reviewed and agreed with PC well fluids during planning.	Yes	
Cement Plug to be set in Inhibited Seawater.	Yes	
Cement vendor modelling (or equivalent simulation / volume and displacement calculations) indicates minimum required TOC will be achieved (based on < 20% contamination).	Yes	
Fluid hierarchy (density & rheology) achieved between ISW/spacer/cement.	Yes	
Next phase of the operation does not require a tag of the cement – if the cement barrier is to be used as a well control barrier for subsequent operations, planned WOC time must have elapsed or additional mechanical barrier set e.g. retrievable packer.	Yes	
Notes: [1] Base Case: rig blend, retarder and dispersant (cement vendor testing) [2] Base consists of deep set mechanical plug and production packer which will have been pressure tested during P&L phase.		

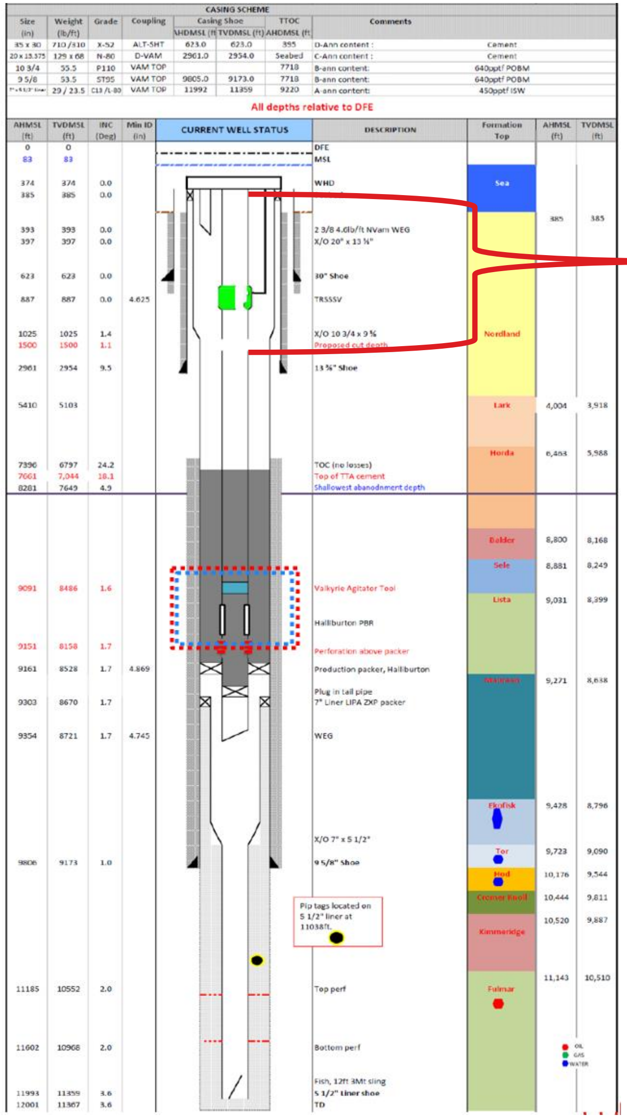
Execution Checklist	Parameters	
Activity	Criteria	Executed
Well is static pre-job (Flowcheck)	Yes	
No losses seen in pre-job circulation or during the execution	Yes	
Observe fluid returns and pump pressures throughout pre-job circulation. Annulus should be free of heavy solids and circulation pressure should be consistent throughout.	Yes	
Prepare mix-water and take samples – correct volume/level in tanks Not always applicable and if no mix water is built samples will be taken while pumping.	Within allowable error	
Ensure pipe movement maintained throughout job (agitator tool)	Yes	
Density check of slurry confirms density between -0.2ppg & +0.4ppg of design density (pressurised mud balance & densitometer). Densitometer data to be stored in CWF.	Yes	(Average reading) Density: Mud bal:
Material usage within expected ranges, comparing pre and post job material stocks (bulk cement & chemicals)?	Within allowable error	Planned: Actual:
Take samples of slurry through job (at least 4 waterbath samples) and store for examination	X Cup Samples taken	
Check level of active (displacement) fluid pit pre-displacement and record if relevant	Yes – Volume / N/A	
Observe fluid returns throughout job to ensure no cement returns are present	Yes	
Volumes and rates as per cement vendor modelling procedure – no pump shutdowns during displacement of cement into annulus (consult with onshore if interruptions during displacement).	Yes	
Check active pit levels post-job – no losses during displacement?	Yes	
Well is static post-job (no more than thermal effects observed)	Yes	
No additional factors that would bring concern about the integrity of the cement plug?	DSV experience - Yes	
Slurry Cup Samples have set on surface at representative temperature. **Note:** It is not uncommon for surface samples to take considerably longer to set than onshore UCA testing due to the lack of pressure at surface compared to downhole conditions. Operations may continue without the slurry cup samples having set.	Yes	
Notes: Variation on fly-mix accepted. Slurry average density should be in this range. Pumping heavy of less concern than pumping light for quality of set plug. Two independent density measurement devices require to be used throughout the cement job (intermittent loss of Densitometer acceptable).		

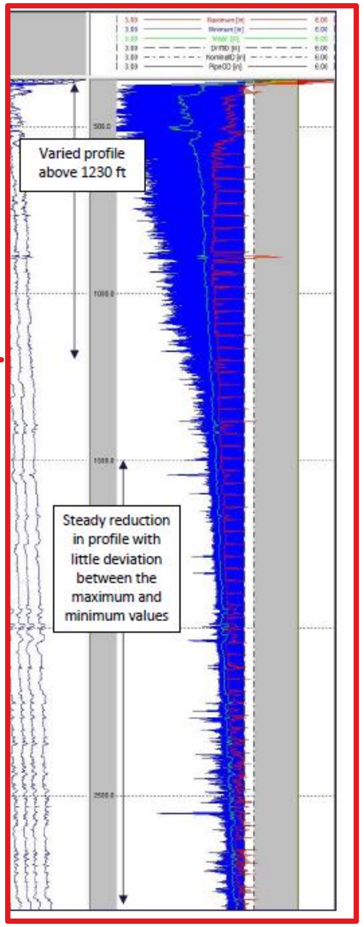
Outcome & Learnings – Well #3

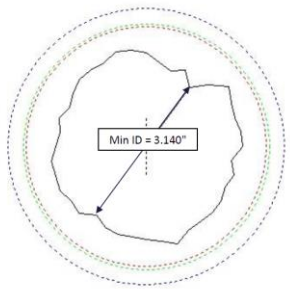
- Scale build-up encountered in production tubing
- Wireline drift unable to get past tubing hanger
- Scale dissolver pumped
- Calliper tool run & wireline drift confirmed considerable scale still remaining from tubing hanger to ~7,500ft MD
    - Unable to run planned deep-set tubing plug
    - Unable to run agitator tool
    - Unable to run tubing cutter

- After risk assessment decision made to continue with TTA operations
    - Contingency high expansion bridge plug set in tubing
    - Low risk for cement channeling
        - Cement modelling showed good quality cement
        - 2deg inclination at base of TTA plug
        - Tubing punched so some centralisation from production packer expected to extend up across base section of cement

- TTA plug placed as per modified plan & verified successfully
- On removing subsea xmas tree bubbles observed discharging from annulus bore of wellhead
- Well left suspended with xmas tree in place
- Plans being worked up for future re-entry for shallow remediation



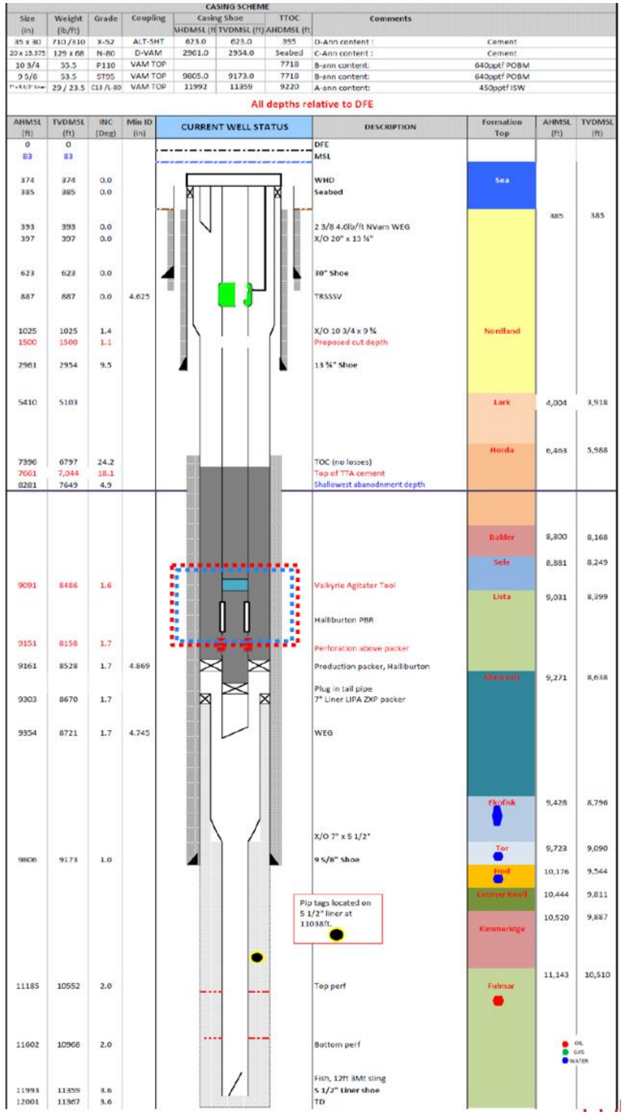




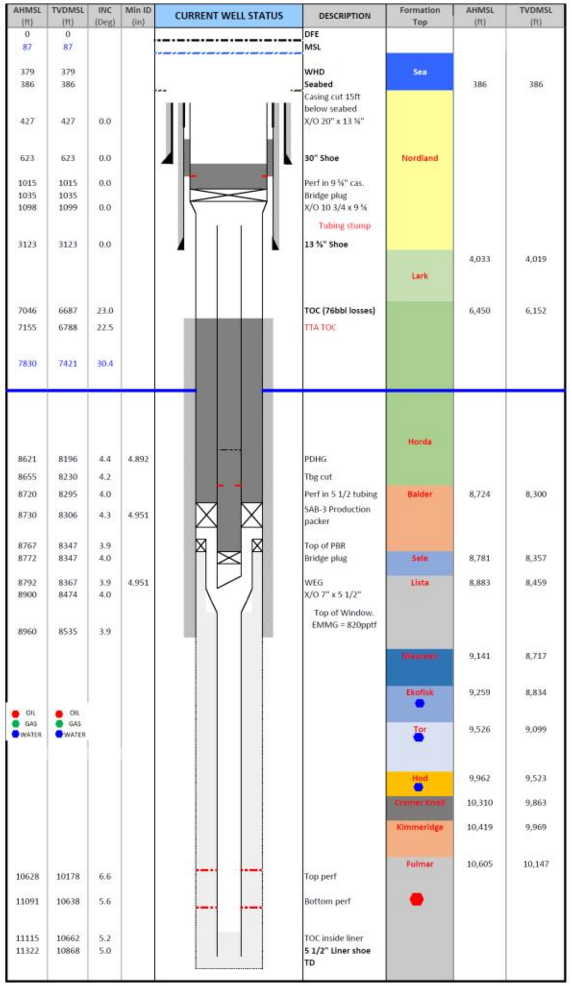
Outcome & Learnings – Well #3

- Analysis of gas samples confirmed source as Fulmar reservoir
- Most probable cause of leak is failure of the TTA cement plug
  - Low level leakage past high expansion bridge plug not detected with pressure tests or build up tests possibly masked by thermal effects.
  - Continued low level percolation through cement as it set

- Key learnings
  - When there is an increased risk of primary mechanical barrier failing further mitigations to reduce the impact include:
    - Use of kill weight brine
    - Use of cement design with gas tight properties (swift static gel strength transition)
    - Hold surface pressure during WOC period to increase overbalance
  - Raises question on whether a 10min pressure test is sufficient duration to rule out a low-rate leak.
  - Consider recovery options for failed TTA plug, can you leave sufficient window below min abandonment depth for a repeat plug?

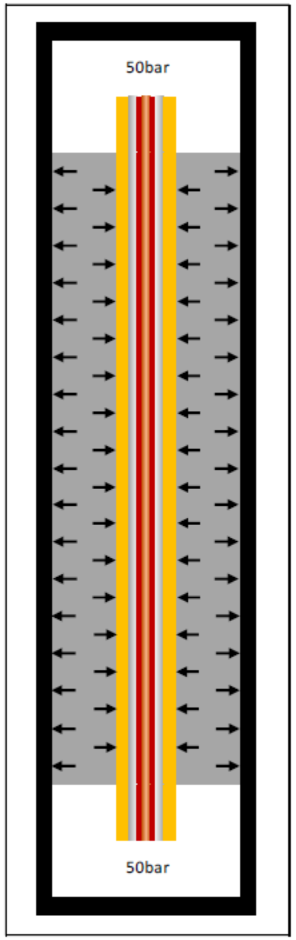


Next Steps for Future TTA



- Continue to expand rig-less P&A capability
  - Placement of environmental barriers & well head severance
  - Recently developed & successfully implemented vessel deployed tubing hanger recovery tool

- Further work on qualification of barrier with gauge cables for future scope
  - Early engagement with UK HSE planned
  - Degradation evaluation for gauge cables
    - Different cable types/encapsulations (ETFE/Nylon/Polypropylene)
    - Extending testing from 6 to 12months
  - Gauge cable internal leak path
    - Wider range of temperatures up to 150C
    - Increased cable length 0.4 to 5m (Cable only – no external cement)
    - Cable encased/confined in cement plug
    - Full system test of open ended cable + cement plug
  - Collaborative engagement with other North Sea operators



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