MANAGING TECHNICAL AND LOGISTICAL CHALLENGES ON A DEEPWATER GAS FIELD PIPELINE PRE-COMMISSIONING AND INSPECTION PROJECT

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Introduction

This paper focuses on the technology and logistical challenges for a long-distance, deepwater pipeline precommissioning and inspection project. Baker Hughes Process and Pipeline Services (PPS) performed this work on behalf of Noble Energy Inc., a major oil and gas exploration and production company. Its subsidiary, Noble Energy Mediterranean Ltd., contracted directly with Baker Hughes PPS as part of their development of a subsea gas production and transportation system connecting the deepwater Tamar Gas Field (see figure 1 below) to an offshore receiving and processing platform linked to the existing Mari-B Platform in the Mediterranean sea.

Gas production from the Tamar Reservoir is designed to occur through five high flow rate subsea wells into the subsea gathering system, which consists of an infield flowline from each well to a subsea manifold. From the subsea manifold, dual subsea pipelines will transport Tamar production approximately 149km to the Tamar Offshore Receiving and Processing Platform where the gas will be processed. The processed gas will then be delivered to the existing Ashdod Onshore Terminal (AOT) for gas sales into the Israel Natural Gas Line (INGL) system.

As with any major deepwater gas development project, there were many technical and logistical challenges. For purposes of clarity only a few of the challenges and technology descriptions are in this paper.

Baker Hughes Project Description & Scope of Work

The pipeline Pre-commissioning and inspection scope of work focused on the pipelines listed below. A detailed table outlining the main service scope tasks is located in the table on the next page.

- Tiebacks (2 x 16" Tieback lines & 2 x 4" MEG Lines)
- Field (5 x 10" Flowlines, Jumpers & Manifold)
- Injection (8" Condensate Injection, 16" Gas Injection, 30" Gas Export Riser & 20" Tie-in Spool)
- Utility Pipelines (1 x 10", 2 x 6")

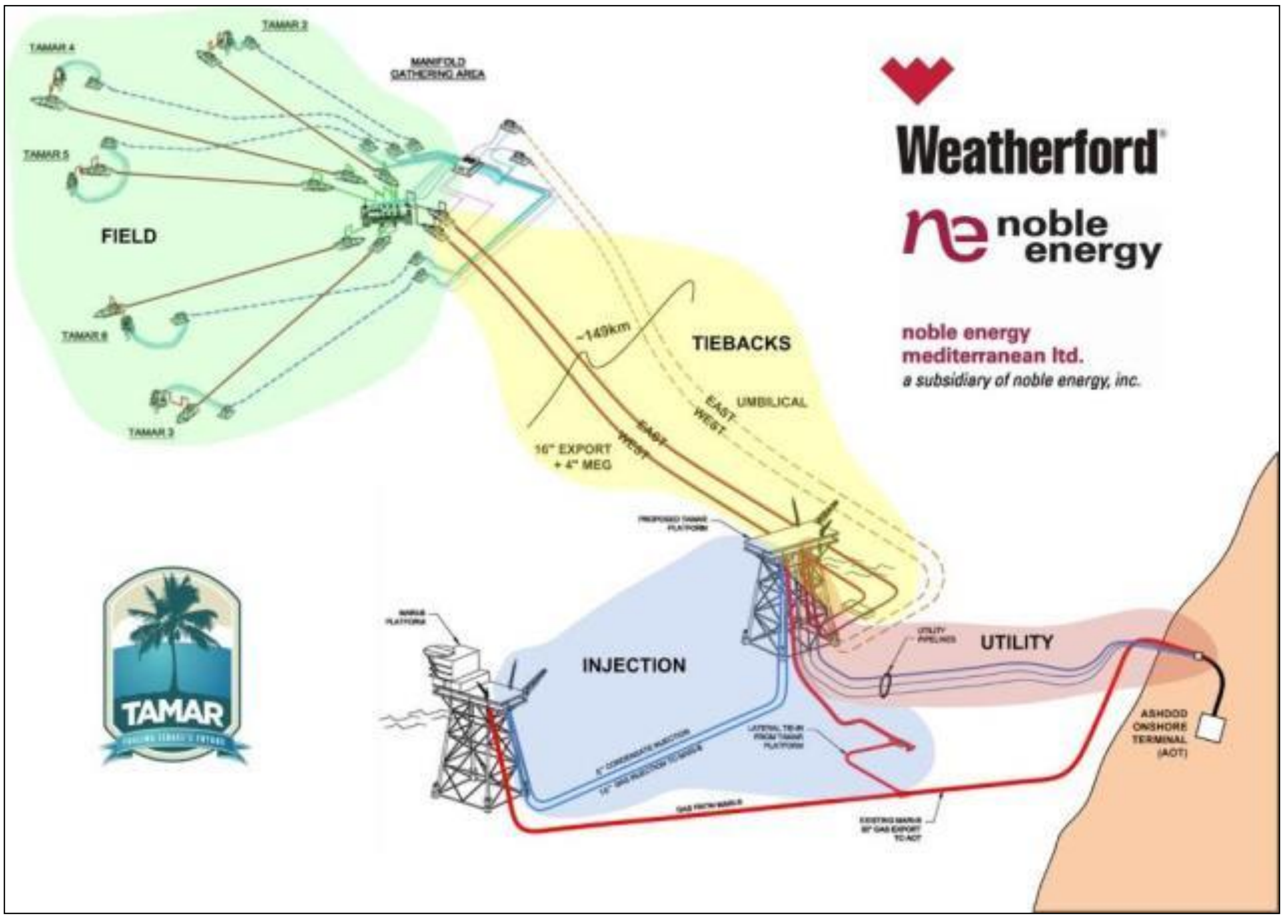

Figure 1 : Schematic of the Tamar Gas Field, Tamar Offshore Receiving and Processing Platform, Ashdod Onshore Terminal (AOT), and Mari-B platform

Phase/Line	Scope of Work
Phase I Tieback Pipelines	- Flood, clean, gauge, and strength test pipeline prior to installation - Baseline survey using Caliper and Ultrasonic inspection - Dewater, dry/swab with inhibited MEG, and nitrogen purge each pipeline - Nitrogen pack tieback pipelines for nitrogen dewatering, drying, and purging activities - Leak test connections for each pipeline following platform and manifold tie-ins. - Dewater, dry/swab with inhibited MEG - Nitrogen purge tieback risers, jumpers, and main manifold
Phase II MEG Pipelines	- Flood, clean, and strength test pipeline prior to installation of riser, tie-in spools, and SDA jumpers - Dewater and fill each pipeline with pH balanced inhibited MEG - Leak test connections for each pipeline following completion of platform and SDA tie-ins - Dewater and fill MEG risers, jumpers, and SDA with pH balanced inhibited MEG
Phase III Infield Flowlines:	- Flood, clean, and strength test each flowline. - Dewater, dry/swab with inhibited MEG, and Nitrogen purge each flowline. - Re-install and externally leak test pressure caps on inline FLET hubs. Internally leak test the pressure cap and displace water in dead legs with inhibited MEG into the main line.
Phase IV Gas & Condensate Injection Pipelines:	- Clean and gauge each pipeline with filtered seawater. - Strength Test each pipeline with filtered and dyed seawater upon completion of platform tie-ins. - Dewater, dry/swab with inhibited MEG, and nitrogen purge each completed pipeline.
Phase V Tamar Sales Gas Export Pipeline:	- Fill pipeline with filtered and dyed seawater. - Leak test the 20-inch crossover to 3.5 bar less than the contemporary local operating pressure of the Mari-B Sales Gas Pipeline to 1.1 x MAOP. - Leak test the 30-inch section of the pipeline to 1.1 x MAOP. - Dewater and fill the 20-inch crossover with dyed and inhibited MEG. - Dewater, dry/swab with inhibited MEG, and nitrogen purge/pack the pipeline.
Phase VI Utility Pipelines:	- Clean and gauge the pipelines with filtered seawater - Strength test the pipelines with filtered and dyed seawater upon completion of platform tie-ins - Dewater, dry/swab with inhibited MEG, - Nitrogen purge the completed 10” Utility 1 pipeline

Table 1: Scope of Work Summary for Pre-Commissioning and Inspection

Challenges & Solutions – Pre-Commissioning

Subsea Flooding, Testing and MEG injection of with Denizen – 10” Infield Flowlines

As part of the pre-commissioning scope, the 5 x 10” deepwater (1,600 – 1,800m) infield flowlines (4-6 km lengths) were flooded, cleaned, gauged and hydrotested. The decision was made early in the project to perform these operations from the seabed using Baker Hughes’ Denizen subsea pre-commissioning system. This strategy allowed the flowline operations to be performed independently of the tie-back lines and associated jumper installation program. In addition to increased schedule flexibility, the remote subsea pre-commissioning approach requires no large vessel-based pumping spread or deepwater downline. The Denizen system takes advantage of the high ambient hydrostatic pressure during the pipeline free flood phase and ROV hydraulic power to drive Baker Hughes' subsea pumps for the pumped flood and hydrotest operations. All salient parameters are logged and displayed subsea via bespoke Denizen logging packages.

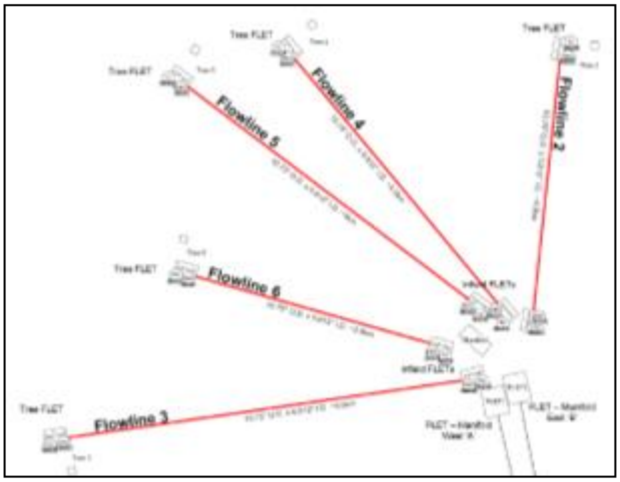

Figure 2 :

Tamar Deepwater Infield 10" Flowlines

Figure 3 :

Denizen Pumping Skid with ROV

To further expedite the development of the Tamar field, Baker Hughes employed a couple of novel subsea operations for Noble Energy. Firstly, on completion of the flooding operations, the Denizen pigging pump was utilized to launch the dewatering pig train with slugs of MonoEthylene Glycol (MEG). This required a custom high volume MEG skid to be deployed subsea and connected to the Denizen Flooding Skid. The benefits of this approach are twofold; no costly downline intervention is required to inject the MEG in deepwater. Additionally, "pre-launching" the pigs in this way allowed the eventual dewatering of the 10" infield lines to be performed via a jumper from the 16" tieback lines, thus all dewatering nitrogen injection could be performed easily from the shallow end of the tieback lines.

The second novel operation employed for Tamar was the use of multiple remote subsea datalogging skid packages during the hydrotesting phase. There is a hydrotest datalogging system built into the Denizen Pumping skid, recording and displaying pipeline pressure, temperature, and pump flow rate. The Pumping Skid's high pressure triplex pump is powered by the ROV's hydraulic system and used to elevate the pipeline pressure by injecting chemically treated and filtered seawater. Once at test pressure the ROV and Denizen Pumping Skid conventionally hold station at the end of the pipeline for the duration of the 12-24 hour hold period. This approach is compromising on a field such as Tamar, where five pipelines in close proximity all require hydrotesting and therefore multiple length hold periods would tie up Denizen and the ROV. To further compress the hydrotesting schedule, Baker Hughes deployed multiple hydrotest logging skids, independent on the main Denizen system and ROV. These logging skids were stabbed into the pipeline and Denizen pressurised through these to test pressure. Denizen was then able to detach from the logging skid and pipeline during the hold period. This approach releases the ROV and Denizen to perform the pressurisation of another pipeline while another pipeline is undergoing the hold period of the pressure test. For this project, our approach resulted in several days' worth of schedule reductions.

Figure 4:

Remote Hydrotest Data-Logging Skid

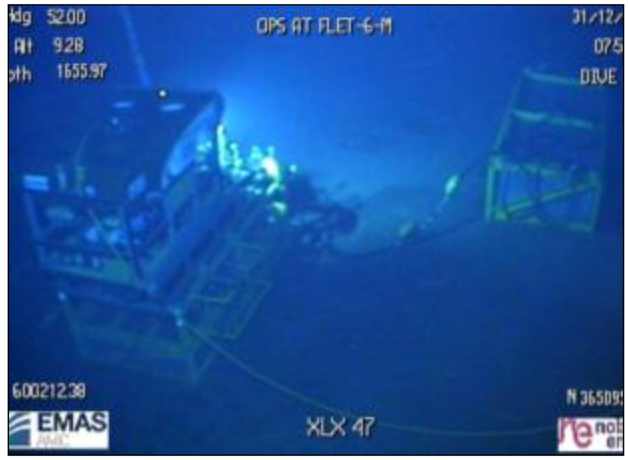

Figure 5 :

Denizen Flooding and 10m^3 MEG Skids Subsea

Dewatering, MEG conditioning and nitrogen purging of the tieback and deepwater flowlines

The twin 147 km x 16" pipelines run from 240m to 1,700 m water depth. Flooding, cleaning and gauging operations were performed from a vessel at the shallow end. During the flooding operations, the In-Line Inspection surveys were carried out. First a caliper tool was pumped through the line to verify minimum bore and a UT tool followed to provide the wall thickness baseline survey. Subsequently, it was a requirement to dewater all 5 kilometers of the Tamar in-field and tie-back pipelines. The diameter of the pipelines and the water depth dictated that a significant amount of specialized compression equipment would be required to complete the dewatering at the required pressure range of 170 - 235 bars.

Baker Hughes was able to use assets from the Temporary Air Compression Station (TACS™) to provide the solution. Adequate compression equipment was available to complete the dewatering, MEG conditioning and Nitrogen purging in a single pigging operation, removing the requirement for any additional post dewatering pigging/purging and leaving the pipelines ready to accept hydrocarbons. A key challenge that needed to be overcome was minimizing the vessel footprint required for the nitrogen spread. This was achieved by very close spacing on the compression spread and an advanced seawater cooling system. The dewatering pig train included MonoEthylene Glycol (MEG) batches between pigs to condition any post dewatering residual water and prevent the formation of hydrates. Additional MEG was also included in the pig train to provide pipe wall desalination.

An unconventional approach was executed by Baker Hughes to allow the dewatering of the 10" infield lines via the 16" tieback lines without the need for a deepwater downline or a second vessel. The tie-back lines were packed to a higher gas pressure (232 bars) than required for their own dewatering (170 bars). The nitrogen from these lines was subsequently routed through a manifold and set of jumpers to drive the pig trains in the 10" infield lines. These pig trains had previously been launched on MEG by the Denizen system and therefore no deepwater downline was required for MEG injection. A stab mounted orifice plate was installed at the discharge end of each 10" infield line to regulate the pig speed for an efficient dewatering operation. Due to the long distance the volume of pressurized nitrogen contained in the tieback lines was sufficient to dewater all five infield lines and still achieve a positive pack pressure with no additional nitrogen injection. This approach saved days of vessel time compared with a conventional approach of dewatering each deepwater infield line via a downline and compression spread on a vessel.

Figure 6:

Nitrogen Dewatering Spread

Figure 7:

Downline connection to Subsea Manifold

Challenges & Solutions – Ultrasonic Wall Measurement (UTWM) Base Line Inspection

Although not originally part of the scope of work, a UTWM baseline inspection was performed on the 16” tieback lines. Considering the huge investment in this deepwater production system, running an Ultrasonic Wall Measurement baseline survey adds enormous value from a long term pipeline integrity perspective.

For this baseline survey Baker Hughes elected to use its latest generation of Ultrasonic (UT) tools[1]. For a deepwater pipeline system, in-line inspection (ILI) accuracy is critical due to the cost of repairs. For this reason, selecting a proven, highly accurate and reliable ILI technology is crucial for a successful deepwater integrity assessment. This latest generation of tools is a field proven technology that uses the most up-to-date UT sensors, software and electronics[2].

Figure 8: UTCD/UTWM Ultrasonic Tool

Ultrasonic Wall Measurement (UTWM) Operating Principle

Ultrasound is a non-destructive testing technology which has been used on in-line inspection tools since the 1980s. The fundamental principle of ultrasonic wall thickness measurement is based on inducing ultrasound compression waves into the pipe wall.

The ultrasonic transducers are positioned at a 90º angle to the pipe wall. The transducers use an impulse-echo mode which means they transmit an acoustic wave and receive return echoes that represent the locations of the internal/external pipe wall and other metallurgical anomalies such as laminations.

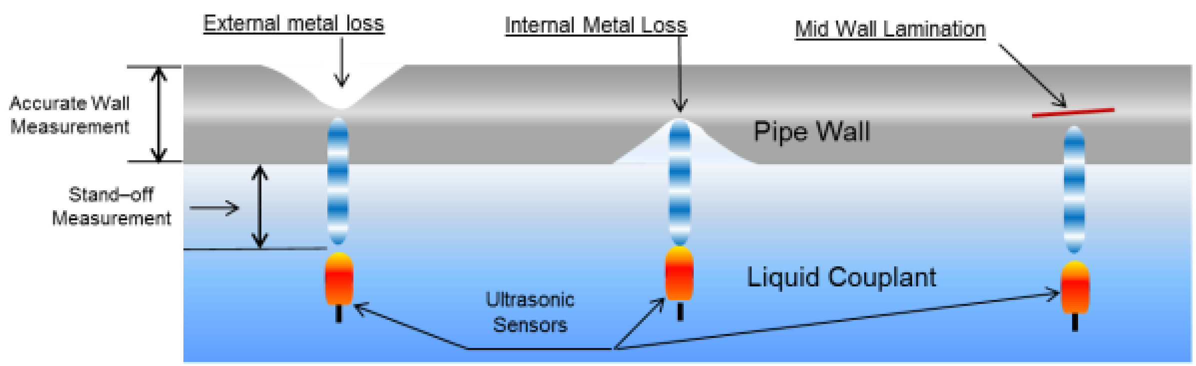

Figure 9: Diagram showing Ultrasonic Principle

Benefits of UTWM ILI Technology

Performing a baseline inspection with the UTWM technology provides superior identification and *classification* of non-injurious signals such as mid-wall laminations or other mill-related anomalies. This provides a better footprint of the pipe at the commissioning stage of the pipeline life cycle, adding value when performing future ILI inspections or integrity engineering assessments. In Appendix A you will find the UTWM Probability of Identification[3] (POI) table that highlights the Ultrasonic ILI tools' detection capabilities.

A baseline corrosion survey using UTWM technology will also provide the most accurate wall loss sizing data. The accurate anomaly classification and sizing provide advantages when comparing the baseline data to future inspection data. All future integrity efforts such as the application of engineering assessments and growth rates will be more accurate because the data feeding into these assessments are more accurate. This higher level of accuracy is especially crucial for deepwater subsea lines where normal onshore NDE validation practices are cost prohibitive. The higher level of accuracy also reduces excess conservatism when assessing anomalies, saving *significant costs* by allowing the operator to allocate its maintenance budget to the correct level of integrity risk.

Two benefits of Ultrasonic technology over Magnetic Flux Leakage (MFL) tools are its better **sizing accuracy of wall loss and of the pipe wall thickness**. The better sizing accuracy is attributable to the physics associated with the ultrasonic pulse echo method, offering a more direct measurement of wall loss than the measurements performed by magnetic flux leakage. However, it should be noted that, in some cases, MFL is the better solution. MFL can be more forgiving of dirt, debris, rough internal pipe surfaces and waxy liquids. For this reason a comprehensive pre-inspection assessment is recommended before deciding on the correct technology. A comparison of defect sizing specifications is shown in the Table 2 below.

Baker Hughes Ultrasonic Wall Measurement (UTWM) Specification				
Measurements are normalized based on 8.0 mm (.312") wall thickness	General metal loss	Pitting	Axial Grooving	Circumferential grooving
Depth at P0D=90%	0.3 mm / (0.01 in)	0.5mm / (0.02 in)	0.3 mm / (0.01 in)	0.3 mm / (0.01 in)
Depth sizing accuracy at 80% certainty	± 0.2mm / (.008 in)	0.3 mm / (0.01 in)	± 0.2mm / (.008 in)	± 0.2mm / (.008 in)
Width sizing accuracy at 80% certainty	± 4mm / (0.16 in)	± 4mm / (0.16 in)	± 4mm / (0.16 in)	± 4mm / (0.16 in)
Length sizing accuracy at 80% certainty	± 3mm / (0.12 in)	± 3mm / (0.12 in)	± 3mm / (0.12 in)	± 3mm / (0.12 in)

Generic Magnetic Flux Leakage (MFL) Specification				
Measurements are normalized based on 8.0 mm (.312") wall thickness	General metal-loss	Pitting	Axial Grooving	Circumferential grooving
Depth at P0D=90%	0.8 mm / (0.03 in)	1.0 mm / (0.04 in)	0.8 mm / (0.03 in)	0.8 mm / (0.03 in)
Depth sizing accuracy at 80% certainty	0.8 mm / (0.03 in)	0.8 mm / (0.03 in)	1.0 mm / (0.04 in)	0.8 mm / (0.03 in)
Width sizing accuracy at 80% certainty	± 10 mm / (0.4 in)	± 10 mm / (0.4 in)	± 10 mm / (0.4 in)	± 12.7 mm / (0.5 in)
Length sizing accuracy at 80% certainty	± 10 mm / (0.4 in)	± 10 mm / (0.4 in)	± 12.7 mm / (0.5 in)	± 10 mm / (0.4 in)

Table 2: Comparison of Baker Hughes UTWM and a Generic MFL Detection and Sizing Specification for Wall Loss

The ability of the UTWM to accurately measure the wall thickness is significant because this has a direct influence on the failure pressure calculation of a corrosion feature. Typical MFL tools are not designed to measure the wall thickness. Rather, the wall thickness is inferred from API pipe specification, pipeline construction data, and/or estimated variations in the magnetic field. This only offers a relative assessment of the wall thickness as pipeline data is often inaccurate or unavailable due to asset transfers of ownership, unavailable pipeline data, or unrecorded pipeline reroutes/modifications.

It should be noted that these inferred measurements do not take into consideration the wall thickness tolerances from the pipe mill (see figure 10 below). In practical terms this means that a MFL corrosion wall loss depth measurement, for example, 0.5t (50% reduction in the wall thickness) is dependent on a relative measurement of the pipe wall, decreasing the sizing accuracy beyond the normal ILI tool sizing tolerance. This is because it is not only the tolerances associated with the ILI tool anomaly sizing but also the tolerances associated with the *actual* pipe spool wall thickness from the mill.

Acceptable pipe wall tolerances[4] from the mill can be as high as ± 10% t (t = pipe wall thickness) for pipe wall thicknesses between 5mm – 15mm in welded pipeline. For pipe walls ≥ 15mm the acceptable mill tolerances are ± 15%t in welded pipe. Because of these pipe mill tolerances and the high corrosion anomaly sizing tolerances from an MFL tool, the calculated failure pressure from an ILI survey can be significantly over or under conservative due to MFL wall thickness sizing inaccuracies caused by depths being quantified as a percentage of the *assumed* wall thickness.

Costs to mitigate corrosion integrity risks can be high for onshore lines. For offshore lines, the cost can be enormous. For this reason confidence in the accuracy of the results is especially crucial for offshore pipelines and therefore choosing the most accurate technology is often the only logical choice.

Most MFL tools obtain a *relative* corrosion depth based on an assumed wall thickness. UTWM tools ***measure*** the actual wall thickness, reducing errors often found with MFL tool's wall thickness assumptions.

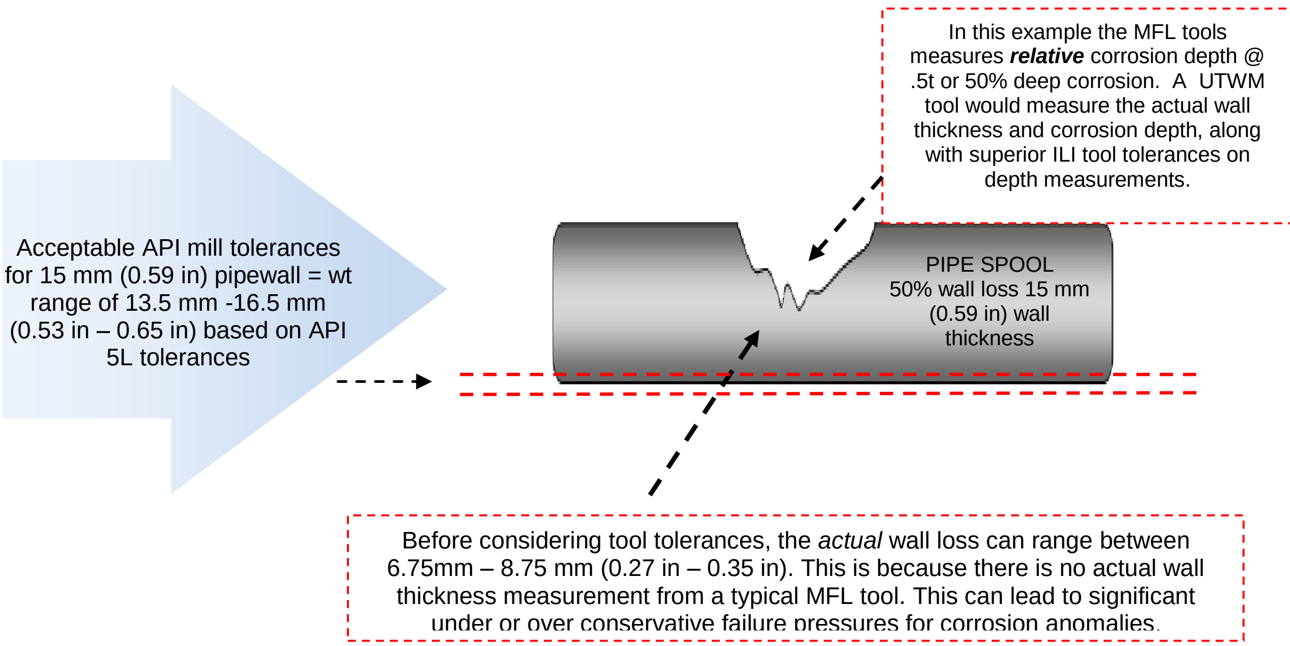

Figure 10: Example of influence of API mill tolerances on MFL depth sizing

Combining accurate ILI tool data with a superior assessment method increases cost-savings

Because of its more accurate corrosion sizing capability, Ultrasonic Wall Measurement inspection data provide the most accurate corrosion sizing to feed into an assessment standard such as B31G, Modified B31G, or and RSTRENG Effective Area Assessment. As noted in predicted versus actual burst testing studies[5], the RSTRENG effective area assessment offers the most accurate results based on actual versus predicted burst pressure tests compared to B31G and Modified B31G. Based on research data an RSTRENG Effective Area Assessment is the most accurate methodology and is recommended for subsea pipelines.

Improved Ultrasonic Wall Measurement Technology

As discussed in previous papers [1, 2], earlier generations of Ultrasonic tools have demonstrated echo losses due to adverse pipeline conditions. By utilizing our most recent generation of Ultrasonic ILI tools for crack or wall loss inspection, dig verification demonstrated improved detection and accuracy, of which some of this improvement is attributed to new sensor technology. API 1163[6] required engineering tests and data analysis from field work[2] that has shown improved sensitivity and reduced signal degradation. These improvements are essential components of a successful deepwater subsea baseline survey. This same sensor technology is also used for the Baker Hughes Ultrasonic crack inspection in-line tools and has demonstrated accurate sizing results that can be used for integrity assessments methodologies such as API 579[7].

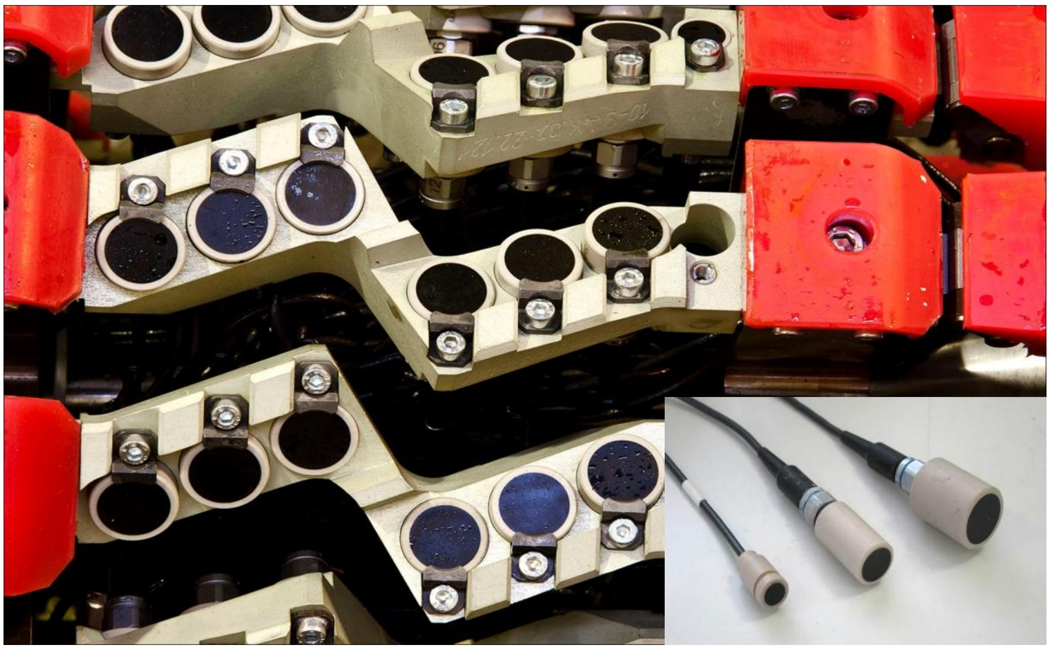

Figure 11: Baker Hughes' latest generation of Ultrasonic sensors

16" Tieback Lines - In-line Inspection Challenge

An interesting challenge for the 16" UTWM ILI inspections was the tight scheduling constraints for a subsea launch. Under normal ILI inspections scenarios, there would be ample battery life for the inspection tool run. However, for this inspection, the tool needed to be activated with a delayed start time. This was required due to the amount of time required for a subsea launch. First, the ILI tool had to be inserted into the Baker Hughes PLR (pipeline launcher receiver) on board the vessel. Then, a vessel crane transported the PLR (with the ILI tool) to the PLEM (see vessel and crane in Figure 10).

Figure 12: Vessel crane performing subsea PLT/ILI delivery

Once the PLT was in position a hydraulic lock was activated to secure the PLT to the pipeline. Finally an ROV was used to turn the subsea valves for the pig launch. This process took considerable time with an increased risk of delays, possibly causing a failed run due to insufficient battery life. To avoid this scenario, it was agreed with the operator we would include an additional 2-hour window for unforeseen delays. With this additional two hour safety factor it was decided to program a 12-hours delayed tool activation from the time the tool was inserted into the PLR on board the vessel (see below photo of one of the topside PLRs).

Figure 13: Manufactured PLR installed topside

Summary

The Tamar Gas Field precommissioning and in-line inspection project was logistically challenging. When performing deepwater pipeline precommissioning there is always a high cost due to vessel time. However, with Baker Hughes' patented Denizen™ equipment, Noble Energy was able to significantly reduce the cost of pipeline precommissioning. Moreover, by utilizing Baker Hughes' fleet of new Ultrasonic in-line inspection tools the client was able to use a single contractor and eliminate logistical and scheduling efforts. Overall, this project was considered a success by all concerned.

References

1. Weatherford New Generation ILI Tools; S. Panteleymonov, PhD, A. Smirnov, Weatherford P&SS, Lukhovitsy, Russia

2. Pipeline Technology Conference March 2012, *Pipeline Inspection Case Study: Design Improvements on a New Generation UT In-line Inspection Crack Tool* – Slaughter; M J, Weatherford International; Huss, Michael, Adria Wein Pipeline Gmbh; et al

3. Pipeline Operators Forum- *Specifications and Requirements for Intelligent Pig Inspection of Pipelines, Version 2009*

4. API 5L, Section 9.11, TABLE 11; *Tolerances for wall thickness;* 44th Edition.

5. Pipeline Research Council International; *Recent Results: A Review of Methods for Assessing the Remaining Strength of Corroded Pipelines;* PRCI Website.

6. American Petroleum Institute; *API Standard 1163, In-Line Inspection Systems Qualification Standard. August 2005*

7. American Petroleum Institute, *API RP, 579 Second Addition.*

APPENDIX A

Baker Hughes UTWM POI

Feature	Yes	No	May Be
	POI[1] > 90%[2]	POI < 50%	50% < = POI < = 90%
Internal/External/Mid Wall Discrimination	X		
Additional metal / material:			
- debris, magnetic	X		
- debris, non-magnetic	X		
- touching metal to metal			X
- deposit	X		
- overlap	X		
Anode		X	
Anomaly			
- arc strike		X	

Feature	Yes	No	May Be
	POI[1] > 90%[2]	POI < 50%	50% < = POI < = 90%
- artificial defect[3]	X		
- buckle	X		
- corrosion	X		
- corrosion cluster	X		
- crack		X	
- dent[4]	X		
- dent with metal loss			X
- gouging	X		
- grinding	X		
- girth weld crack		X	
- girth weld anomaly			X
- HIC	X		
- inclusion	X		
- lamination	X		
- longitudinal weld crack		X	
- longitudinal weld anomaly			X
- mill anomaly	X		
- ovality		X	
- pipe mill anomaly	X		
- pipe mill anomaly cluster	X		
- slotting	X		
- SCC		X	
- spalling	X		
- spiral weld crack		X	
- spiral weld anomaly			X
- wrinkle[4]	X		
Crack arrestor	X		
Eccentric pipeline casing		X	
Change in wall thickness	X		
CP connection / anode	X		
External support		X	
Ground anchor		X	
Off take	X		
Pipeline fixture[5]	X		
Reference magnet		X	
Repair:			
- welded sleeve repair	X		
- composite sleeve repair		X	
- weld deposit	X		
- patch	X		
- coating		X	

Feature	Yes	No	May Be
	POI[1] > 90%[2]	POI < 50%	50% < = POI < = 90%
- Tee	X		
- Valve	X		
Weld:			
- bend	X		
- diameter change	X		
- wall thickness change (pipe/pipe connection)	X		
- adjacent tapering	X		
- longitudinal weld	X		
- spiral weld	X		
- not identifiable seam	X		
- seamless	X		