 Collaborative Effort Enables Repair of Prolific Gas Well with Solid Expandable Chrome Liner
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Abstract
A prolific gas-condensate well in the Caspian Sea was forced to shut in due to a leak in a premium connection of the 7 in. production tubing resulting in loss of well integrity. Immediate repair was required to re-establish production. An expandable tubing patch (solid expandable cased-hole liner) was selected to provide a high-pressure, gas-tight, and potentially long-term repair of the leak while minimizing the loss of wellbore internal diameter (ID). In a very short time frame, engineering teams successfully collaborated to design, manufacture, and qualify the expandable tubing patch to a V0 (zero-bubble acceptance criterion) test protocol.

The tubing patch was successfully installed without killing the well using a single downhole barrier and a snubbing unit. The well was returned to production in May 2007, and has been on continuous production without any evidence of a re-occurrence of the tubing leak. This paper will review the well engineering, design engineering, qualification testing, QA/QC, and operational installation planning. Close teamwork between the end user and the expandable provider resulted in the successful repair of the well and allowed the operator to progress the return of the well to service.

Introduction
The Shah Deniz field, confirmed in 1999, is a giant high-pressure gas condensate field containing approximately 30 TCF of gas and a significant amount of condensate offshore Azerbaijan in the Caspian Sea (Figure 1). Shah Deniz Stage 1 sanctioned 12 wells with further development planned in the field with a life estimated to more than 30 years. Well conditions are near HPHT with a reservoir pressure of 12,500 psi at 20,000 ft (~6,100m) TVD and a static reservoir temperature of 212°F. Drilling and production occur from the Shah Deniz Alpha (SDA) platform in water depth ~330 ft (~100m) (Figure 2). Licensees and subsequent interests in the Shah Deniz Exploration, Development, and Production Sharing Agreement (EDPSA) include the following:

- BP, operator – 25.5%
- StatoilHydro – 25.5%
- State Oil Company of the Azerbaijan Republic (SOCAR) – 10%
- LUKoil – 10%
- Nico – 10%
- Total – 10%
- TPAO – 9%

Wells producing from the Shah Deniz field are among the most prolific in BP’s global portfolio. As such, the integrity of these wells is essential to the company’s strategy for exporting gas from the Caspian Sea.

Shah Deniz Completion, Start-up, and Tubing Leak
The first well on the Shah Deniz Alpha (SDA-01) platform was completed and brought on line in late 2006. Figure 3 illustrates a typical completion wellbore in the Shah Deniz project. During initial ramp up of SDA-01, the well behaved as expected, although gas and condensate rates were higher than anticipated. The high rates caused flare instrumentation damage due to overheating at the gas terminal that resulted in sudden shut down. When the well was put back on line one
month later, tubing-to-casing communication became evident within a few hours of bringing the well on production. The leak was first identified via pressure monitoring of bleed cycles during production ramp-up. Pressure in the production tubing by casing annulus became unmanageable and the well had to be shut in.

An ultrasonic leak detection log run on wireline confirmed a leak in the connection of the 7-in. pup joint immediately above the mudline tubing hanger (MLTH) at 525 ft (160m) (Figure 4). While pursuing a rig workover option to pull the production tubing, the Shah Deniz wells team identified a less-intrusive solution for isolating the leak that provided short-term production benefits without the risk, cost, and production delay of a rig workover. Attempts to seal the leak using a sealant (liquid-based polymer) were successful but short-lived. The team continued to consider other approaches that offered a potentially more lasting solution.

The Solid Expandable Liner Solution
By early January 2007, the Shah Deniz wells team had completed a review of possible repair options that included both mechanical straddles and expandable patches, and ultimately decided the solid expandable approach to be the most prudent. The Shah Deniz wells team and the Houston-based Exploration & Production Technology Group (EPTG) solid expandable tubular team identified three providers of cased-hole liners that had the potential to supply a patch system for managing the leaking connection.

Solid expandable cased-hole liners have been used to address problems that range from remediating thief zones in injection wells1 to sealing perforations or damaged casing for enhanced production with high-pressure frac jobs2. Another common use of solid expandable liners is to remediate casing connector leaks. The installation system for this patch solution has a 40-year legacy of expanding thin-wall casing repair systems and, more recently, has been retro-fitted for expandable casing. This cased-hole liner system typically consists of a cone assembly, hydraulic jack, and hydraulic hold-down system (Figure 5). However, the optional hydraulic hold down was not used on this installation. A general expansion process (Figure 6) consists of the following steps:

- Pick up the cased-hole liner system BHA (cone assembly and expandable tubular anchor with seals) and set in the slips.
- Run in the hole (RIH) additional expandable tubulars until the desired length of expandable liner is made up.
- Rig up the false floor over the deployed expandable casing.
- Pick up and RIH the inner string that connects the cone assembly to the hydraulic expansion jack assembly. Latch the inner string to the cone assembly.
- Pick up and RIH the inner string with a latch affixed to the bottom of the inner string that facilitates the connection of it to the hydraulic expansion jack assembly (the BHA). Latch the inner string to the BHA.
- Pick up the hydraulic expansion jack and secure to the inner string.
- Rig down the false floor and run the expansion assembly and expandable casing (patch) to the desired depth on the workstring.
- Apply pressure through the workstring. Applied pressure causes the hydraulic hold-down assembly (if utilized) to anchor the top of the hydraulic expansion assembly to the base casing.
- Continue increasing hydraulic pressure through the workstring. The hydraulic jack will stroke, pull the cone up into the expandable anchor joint, and expand the anchor joint seals and mechanical anchor.
- Release hydraulic pressure to release the hydraulic holddown-assembly anchor (if utilized).
- Pull up the workstring 5 ft (~1.5m) to reposition the hydraulic jack to allow cycle repetition until the entire length of the liner is expanded.
  Alternatively, once the first jack stroke is completed, anchoring the bottom of the expandable liner, overpull by the rig can be used to expand the remaining length of liner.
- Pull out of the hole with the expansion jack assembly after fully expanding the liner.

Designing and Qualifying the Tubing Patch (Solid Expandable Cased-Hole Liner)
The team decided that Weatherford’s solid expandable MetalSkin® cased-hole liner provided the best option to avoid a costly, time-consuming, and risky de-completion of the SDA-01. This system could be custom designed and qualified (fit-for-purpose) in the shortest time frame and still meet the challenging wellbore conditions. The patch design considered an installation location with high pressure (SITP ~9,000 psi) and large temperature variations (40 to 180°F). These arduous conditions, coupled with the requirement to qualify the patch to an ISO-type V0 (zero-bubble acceptance criterion) test protocol, lead to the formation of a multi-discipline team of experts within BP, StatoilHydro, and Weatherford to work and manage the project. A significant advantage identified early by the project team was that the patch could be designed without connections. At the same time, the team recognized that expected wellbore conditions would subject the elastomer elements to large stress variations. These elastomer elements form the primary sealing mechanism between the well stream and the leaking connection.
Defining Tubing Patch Statement of Requirements (SOR)
The Shah Deniz wells team identified and communicated the initial statement of requirements (SOR) for a 7 in. (nominal) expandable patch solution for the SDA-01. The team defined the requirements as follows:

- ID (post-expansion): 5.00 in. desired to access top no-go of SCSSV profile (4.50 in. minimum ID required to allow tubing cutter passage prior to tubing cut and pull).
- OD (unexpanded): 5.775 in. (0.02 in. less than minimum ID restriction in completion).
- Length: As required, however, proposed patch solution to isolate leak in MLTH sub-assembly must permit full access to MLTH inner mandrel below; i.e., no incremental materials left across the inner mandrel post-expansion, to allow placement of wireline tubing punch charges across MLTH releasing mechanism.
- Minimum temperature: 5°C.
- Maximum temperature: 90°C.
- Burst resistance: 9,000 psi.
- Collapse resistance: 1,500 psi.
- Materials: 13 chrome (compatible with 13CRS110).
- Material yield strength: Sufficient to achieve desired burst and collapse strengths post-expansion.
- Elastomers: Compatible with Shah Deniz packer fluid (Table 1), 70 to 100% MEG/fresh water blends, nitrogen, and Shah Deniz reservoir fluids.
- Compliance: Must expand out to 7 in., 38 ppf maximum/minimum drift ID range, and remain fully compliant over leaking connection.
- Number of units: two.
- Delivery: 12 weeks (in Baku).
- Qualification: Finite Element Analysis (FEA) using expanded patch material properties to be performed by Stress Engineering.

**Product** | **Function** | **Concentration**
---|---|---
Safe Cor | Corrosion inhibitor | 55 gal/100 bbl
Safe Scav Ca | Oxygen scavenger | 15 lb/100 bbl
Gluteraldehyde | Biocide | 5 gal/100 bbl

Table 1 – Packer fluid formulation.

- Additional functional requirements:
  - Any elastomer design must consider the effects of rapid decompression on the overall system design. The 7 in. leak on SDA-01 is above the SCSSV and any unplanned shut-in may involve bleeding off above the closed SCSSV.
  - Installation process to be minimally intrusive to avoid junk/debris left in wellbore post-expansion.

Engineering Design, FEA and Qualification Testing
The cased-hole liner system consists of an updated version of the decades-old HOMCO patch. While still providing the patch in its original configuration, Weatherford recently incorporated state-of-the-art solid expandable tubulars to replace the corrugated tube of the original design. The patch used on the SDA-01 incorporated 15 ft (~4.5m) of 5-1/2 in., 17.0 ppf, 13Cr80 tubing with multiple elastomer seals bonded on the OD. To meet dimensional requirements, the patch was designed to result in an ID reduction of less than 0.8 in. from the parent casing while providing pressure integrity up to 9,000 psi. Because of the patch configuration, post expansion cleanout was not required. Although the system is typically run on drillpipe and expanded in one trip with a solid cone and hydraulic expansion tool, a snubbing unit was used as a secondary barrier to avoid killing the well during installation of the patch.

FEA
Weatherford performed a detailed design of the proposed patch that included several FEA iterations of the expansion process (Figures. 7, 8, and 9). High sealing pressure was an obvious concern, as was preventing damage to the parent tubing, minimizing the expansion force, and understanding thermal-induced load effects. Design of the fit-for-purpose expandable system involved extensive FEA to select the proper diameter of the expansion swage and thickness of the HNBR elastomers.
The combination of these two parameters affected maximum expansion force and post-expansion performance of the patch. Lab tests were performed at Weatherford’s Technology Centre in Houston to fine-tune the empirical models versus the actual results. Two samples were expanded in the lab and hydro-tested before the patch design was finalized. In parallel, the running tool components were designed and built. Multiple patches were made, designating two for the job and two for V0 testing.

**Qualification Testing**

To facilitate patch qualification and accurately mimic post-expansion well geometry, several 7 in., 38.0 ppf, Cr13-110 pup joints were shipped from Baku to Houston. While the actual V0 qualification process took place in a Houston-based third-party engineering laboratory (Mohr Engineering, a division of Stress Engineering Services), a test sample was created at Weatherford’s Houston Technology Centre by expanding a full-scale patch into one of the pup joints. The elastomer seals were pressure tested at ambient temperature to 9,000 psi with air using water as the test fluid. The first test attempt was unsuccessful, making it necessary to re-size the expansion cone and impart additional compression into the elastomer sealing elements. The patch was then transferred to Mohr Engineering for V0 testing.

**V0 Testing**

The ISO-type V0 (zero-bubble acceptance criterion) testing was conducted to quantify the pressure and temperature operating envelope for the expandable patch. Interested-party representatives from BP and Weatherford monitored the entire testing process that included expanding a patch into the 7 in., 38 ppf tubing pup joints provided by BP. The test set-up (Figures 10 and 11) made use of a 400,000 pound hydraulic cylinder to simulate thermally-induced end loads on the parent tubing that were equivalent to well conditions.

Over several days, the sample was temperature-cycled between 40 and 190°F. Internal pressure was applied with nitrogen up to 9,000 psi. Annular pressure, through porting added to the coupling in the parent tubing, was applied with nitrogen up to 3,000 psi. In addition, tensile loads of 270,000 lb and compressive forces of 70,000 to 100,000 lb were applied to the parent tubing during the cycles.

Figure 12 shows the operating envelope established for the expandable patch (Note: Positive pressure is internal to the patch; negative pressure is annular). As shown by the envelope, patch performance for high pressure under cold temperature was limited to 8,500 psi, slightly less than the 9,000 psi target, but deemed acceptable for this application. At an annular pressure just over 2,500 psi, the patch deflected slightly, allowing minute leakage across the seals. However, the patch was leak-tight at 2,500 psi and below, which was deemed acceptable for this application.

**Manufacturing QA/QC**

Critical equipment manufacturing quality control plans (QCP) are purchaser-specific and typically codify a significant level of review and surveillance by a third-party inspector (TPI). On some occasions, the purchaser may specify additional and/or more onerous quality requirements. The review generally covers procedures and work instructions associated with the manufacturing process and with the documentation (e.g., material certificates) of equipment component parts. The surveillance activities—hold (H), witness (W), monitor (M) and review (R) points—for manufacturing activities begin with contract review and end with packaging and shipping. Critical equipment QCPs are normally biased towards witness points for critical activities such as material verification (e.g., hardness testing), dimensional inspection, set-out, and assembly. Although the casing patch consisted of a single component together with elastomers and a carbide anchor on the OD (Figure 13), BP still followed the principles of the critical equipment QCP and dispatched a TPI to complete a full documentation review, witness the elastomer bonding process, and witness the final inspection.

**Shop Assembly QA/QC**

Critical equipment shop-assembly QA/QC focuses on purchaser involvement in the inspection, assembly, and test of the critical equipment that involves make-up of installation tools with the manufactured equipment (to be permanently installed). At the most rudimentary level, the purchaser or a TPI will witness shop activities as per the suppliers’ procedures and work instructions. On another level, a purchaser-specific shop assembly QCP may be developed in a similar format as a manufacturing QCP with the same surveillance activities identified—hold (H), witness (W), monitor (M) and review (R) points. This type of plan is also referred to as an Inspection and Test Plan (ITP).

For this casing patch application, the HOMCO legacy installation tools were subjected to a full inspection as per BP procedures. Because material traceability was not available for all tools in this case, hardness values were taken to ensure key material properties. A TPI witnessed all inspection activities. The installation tools and the casing patch were assembled and tested in Pearland, Texas, and monitored by representatives of BP and Weatherford. During the assembly process, shear pins and o-rings were verified. The final assembly was pressure tested successfully in accordance to the procedure.

**Planning and Installation**

A series of detailed pre-job planning sessions included all stakeholders and the supervisory crew of the snubbing company. In addition to the necessary engineering design, qualification testing, and QA/QC, detailed procedures were developed by all critical service providers and operator technical personnel.
High-Level Installation Procedure
The following high-level installation plan provided the foundation for a significantly more detailed procedure developed prior to on-site execution.

1. Handover well from production to drilling. Install single well-control panel and take control of the well. Close SCSSV, inflow test, close LV, set up continuous DHGP monitoring from the drill floor.
3. Remove tree cap.
4. Skid snubbing unit with rig to SDA-01.
5. Set down heavy-duty (HD) riser on Xmas tree. Re-connect hydraulic hoses. Pressure and function test well control systems.
6. Rig down snubbing unit to rig floor.
7. Rig up 15k wire line PCE on top of snubbing riser 7-1/16 in. flange. Pressure test 15k PCE to 11kpsi.
8. Run thru-tubing logs (caliper and camera).
9. Rig down electric line and PCE.
10. Rig up upper part of snubbing unit above rig floor and install 3-1/2 in. slip rams in #7(gun locator BOP).
11. Hook up hydraulic hoses, function test, and perform BOP tests.
12. Pick up dummy patch, RIH to MLTH profile, POOH, and inspect for damage.
13. Pick up JRC locating tool for MLTH profile, RIH and locate, mark pipe, POOH.
14. Pick up and RIH with 7 in. scrapers to MLTH, POOH (contingency).
15. Rig up patch handling equipment (false bowl and slips, elevators, power tongs). Check DHPG.
16. Pick up patch and RIH on 3-1/2 in. workstring without BPVs.
17. Space out patch across tubing leak according to JRC correlation run.
18. Expand patch according to Weatherford procedures. Monitor the A annulus for fluid returns while expanding hydraulically to detect presence of leak.
19. Dump pressure on tubing string and POOH.
20. Rig down patch handling equipment.
22. Hang off snubbing unit in top drive and disconnect HD riser from Xmas tree.
23. Skid rig with snubbing unit.
24. Pressure test SDA-01 Xmas tree and tree cap with nitrogen.
25. Handover well drilling to production.
26. Rig down upper part of snubbing unit/BOP/ riser and lines.
27. Rig down snubbing riser and lower BOP to rig floor. Rig down slips, elevators, etc.
28. Demobilize snubbing equipment. Clean all areas.

SDA-01 Tubing Patch (Solid Expandable Cased-hole Liner) Installation Operations
The 460 snubbing unit was fully rigged-up on another well when the decision was made to install the expandable patch in SDA-01, prompting the rig and snubbing unit to be skidded to the location. Caliper and camera logs were run prior to the patch installation. The live well status necessitated electric line pressure control equipment (PCE). Because the tubing leak was above the SCSSV, the barrier envelope above the safety valve was compromised. A risk and operational review performed on rigging up the PCE in the snubbing basket concluded it would be more expedient to rig down the snubbing equipment to the rig floor and rig up the e-line PCE on the rig floor on top of the lower snubbing BOP stack. The caliper confirmed no obstructions in the wellbore and confirmed that the ID across the proposed patch setting area was within the assumed tolerance used for the FEA analysis.
After completing the e-line work, the upper snubbing stack was rigged up again (Figure 14). Three runs were performed with the 3-1/2 in. snubbing string.

The first run was with a dummy, which was dimensionally equivalent to the actual tubing patch and included an identical elastomer seal configuration. The custom-built 45-ft (~14m) dummy BHA with elastomers on the lower 15 ft (~4.5m) simulated the OD and stiffness of the expansion tool BHA to ensure that the elastomers would not be damaged while RIH. The dummy run to 521 ft (158.82m) showed no observable damage or abrasion of the elastomers.

The second trip was a correlation run with the JRC locator tool. The locator tool is designed to fit the selective profile in the top of the MLTH. The JRC tagged the MLTH profile at ~524 ft (159.63m), marginally higher than expected. The patch setting depth was adjusted and agreed upon to account for the new depth datum. The optional scraper run was unnecessary because the camera confirmed a clean, dry wellbore and the elastomer seals on the dummy patch indicated no damage.

A safety meeting held prior to picking up the expansion BHA helped ensure that all parties were familiar with the operation and comfortable with the procedure. The patch and running tool dimensions were checked prior to RIH. The MetalSkin® patch and inner string were picked up and made up to the setting tool. This BHA was run to the setting depth (bottom of the patch at ~522 ft [159.11m]) through the snubbing unit. The workstring was filled with 70/30 MEG and a TIW valve and flow line was rigged up. Surface lines were pressure tested and the TIW was opened in preparation for setting the MetalSkin patch.

Pumping began at the lowest flow rate attainable. The workstring pressure steadily increased from 0 to 1,550 psi (+100 psi) where it levelled off before continuing to increase. Pumping continued and was stopped when 4,700 psi was reached, facilitating the stroking of the running tool’s jack. This five foot stroke expanded the first five foot length of the patch which included the expansion of its anchor and elastomer seals. The pressure was held for five minutes before being bled off. To ensure full expansion, the workstring was re-pressured to 4,700 psi and again bled off. The workstring was then picked up to reset the running tool’s jack and a positive indication of weight was observed after picking up ~5 ft (1.485m). This pressure cycle was repeated; however, the workstring was only picked up 4.625 ft (1.410m) before weight was seen. On the running tool’s third pressure-up cycle, no indication of exiting the top of the patch was noticed as expected. After picking up 4.625 ft (1.415m), weight was again seen. The running tool was pressured up a fourth time and as soon as 1,550 psi was reached the running tool began to stroke and a positive indication of the expansion cone exiting the top of the patch was reflected when the workstring pressure dropped off. Figure 15 gives the expansion forces required to expand the patch. The setting tool was then retrieved and laid down without issue. Upon visual examination, the setting tool and expansion cone indicated full expansion and no downhole issues.

Installation went smoothly and no major issues were encountered during the process. The 5-ft (~1.5m) stroke expansion tool was expected to exit the top of the 15 ft (~4.5m) patch after three strokes because of MetalSkin shrinkage during expansion. However, after three strokes, the expansion cone did not exit the top of the patch and required an additional stroke (Table 2). The slightly shortened stroke length (<5 ft) of the second and third strokes of the setting tool required necessitated a fourth stroke.

<table>
<thead>
<tr>
<th>Stroke</th>
<th>Pick-up Length (meter)</th>
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<tbody>
<tr>
<td>1</td>
<td>1.485</td>
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<tr>
<td>2</td>
<td>1.410</td>
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<tr>
<td>3</td>
<td>1.415</td>
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<tr>
<td>4</td>
<td>Patch Exited</td>
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</table>

Table 2 – Running tool pick-up length required to stroke jack.

During the first stroke, the design of the jack was configured such that the workstring was isolated from any axial loads. On subsequent strokes, however, the tubing was subjected to the reactive expansion force (70,000 to 75,000 lb), which amounts to ~0.3 ft (~0.090m) of stretch according to standard stretch tables. The stroke lengths came very close to actual results when stretch was factored. Although this stretch presents no negative effects, it could be eliminated in future installations by running a hold-down sub above the setting tool to isolate the workstring from axial loads on subsequent strokes. Figure 16 illustrates the post-expanded configuration of the cased-hole liner.

Both the lubricator valve and production packer maintained complete pressure integrity throughout the entire operation and snubbing against well pressure was not required. Upon patch installation, the rig and snubbing unit were skidded to another well slot.
Post-Installation Performance
The SDA-01 was returned to full production rates soon after the successful installation of the solid expandable tubing patch. The well operating guidelines were modified based on the performance envelope obtained through V0 testing as follows to ensure the long-term survivability of the tubing patch:

- Maintain differential across the patch (tubing to A annulus) below 6,600 psi.
- Preferred differential the same as the patch experienced since installation: 4,100 to 5,800 psi. While shut-in, temperatures lowering to ambient conditions are unavoidable especially at the patch depth.
- Avoid positive pressure from the A annulus exceeding the patch collapse rating of 2,250 psi.
- Avoid fluids (especially liquids) passing through the patch seals by managing the pressure in the annulus if a leak develops across the patch.
- Avoid placing liquids across the patch.
- Avoid sudden changes in pressure and temperature as much as practical when returning the well to production.

Since installation in May 2007, the patch has been subjected to a large number of pressure variations. Some of these have been of a high magnitude with a short duration. Shortly after installation, a transient event occurred where the patch saw a differential pressure in excess of 9,000 psi with no resulting leakage. From installation in May 2007 to February 2008 the patch has been subjected to several more pressure transients, but maximum differential pressure has not been significantly above 7,000 psi.

Conclusions
- The SDA-01 tubing leak was successfully repaired with a fit-for-purpose expandable tubing patch (solid expandable cased-hole liner).
- The tubing patch was installed without killing the well using a snubbing unit.
- A multi-discipline team of experts representing various stakeholders worked together to expedite the design, qualification, and installation of the tubing patch. The entire process from order to installation took less than two months.
- Extreme qualification testing (V0) ensured the tubing patch was qualified to the well service conditions.
- A significant level of QA/QC provided assurance for the manufactured equipment and the installation tools.
- Actual well performance has met or exceeded the original repair objectives.
- The SDA-01 has been on production since May 2007 with no evidence of any tubing leak to date.

Acknowledgements
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Nomenclature

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Definition</th>
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<tr>
<td>BHA</td>
<td>Bottomhole assembly</td>
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<td>BHP</td>
<td>Bottomhole pressure</td>
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<td>BHT</td>
<td>Bottomhole temperature</td>
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<tr>
<td>CGR</td>
<td>Condensate gas ratio</td>
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<tr>
<td>EIA</td>
<td>Equipment integrity assurance</td>
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<tr>
<td>ID</td>
<td>Internal diameter</td>
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<tr>
<td>ITP</td>
<td>Inspection &amp; test plan</td>
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<tr>
<td>LV</td>
<td>Lubricator valve</td>
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<tr>
<td>MEG</td>
<td>Mono-ethylene glycol</td>
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<tr>
<td>MD</td>
<td>Measured depth</td>
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<tr>
<td>MLTH</td>
<td>Mudline tubing hanger</td>
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<td>OD</td>
<td>Outside diameter</td>
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<tr>
<td>PCE</td>
<td>Pressure control equipment</td>
</tr>
<tr>
<td>QA/QC</td>
<td>Quality assurance/Quality control</td>
</tr>
<tr>
<td>QCP</td>
<td>Quality control plan</td>
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<tr>
<td>SOR</td>
<td>Statement of requirements</td>
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<tr>
<td>SCSSV</td>
<td>Surface controlled subsurface safety valve</td>
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<tr>
<td>SITP</td>
<td>Shut-in tubing pressure</td>
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<tr>
<td>TD</td>
<td>Total depth</td>
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<tr>
<td>TPI</td>
<td>Third party inspector</td>
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<td>TVD</td>
<td>True vertical depth</td>
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<tr>
<td>WHP</td>
<td>Wellhead pressure</td>
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References
Figure 1 – Location of the Shah Deniz field.

Figure 2 – The Shah Deniz Alpha (SDA) platform.
Figure 3 – Typical wellbore schematic in the Shah Deniz project.
Figure 4 – SDA-01 upper completion and location of tubing leak.

Figure 5 – Cased-hole liner system and setting tool.
Expansion Assembly with cased-hole liner run in hole

Pressure applied, hydraulic jack strokes expanding bottom anchor & seals

The remainder of the casing is expanded with repeated jacking or straight over-pull

Figure 6 – Expansion process to set cased-hole liner.

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