Schlumberger

# Testing Services Pressure Operations Manual

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| Reference: | InTouch Content ID 3045666 |
| Version: | 8.3 |
| Release Date: | 14-Jan-2015 |
| EDMS UID: | 1648592940 |
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| Author: | Hugues Trifol, Jean-Noel Mauzé |

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# Revision History

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| 6.0 | 31-Mar-2008 | Complete update of the manual - See appendix F for more details | **Author:** SRPC Doc-TBT |
| 7.0 | 20-Jan-2011 | Complete update of the manual - See appendix F for more details | **Author:** SRPC Doc-TBT |
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| 8.1 | 01-Feb-2013 | Evolution of version 8.0 to version 8.1 of the manual - See appendix F for more detail | **Author:** Stephane Moreau/Jean-Noel Mauzé **Reviewer:** Jean-Noel Mauze **Approver:** JL Monnac |
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# Table of Contents

# List of Figures

# List of Tables

# Introduction and General Concept

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# 1 Introduction and General Concept

## 1.1 Scope

Schlumberger must ensure that all operational pressure containing and pressure-controlling equipment is qualified for the intended use and that the equipment is never used outside the design specification. Equipment failure caused by non-compliance to defined standards (poor or non-existing maintenance/certification renewal) or equipment used outside its operating envelope can have severe consequences. Failure of pressure-containing or pressure-controlling equipment can cause substantial damage to property and cause fatalities of both Client and Schlumberger personnel.

The Testing Services Pressure Operations Manual (POM), Revision 8.2, released -actual release date: January 31$^{th}$, 2014 is the internal standard in terms of pressure regulation and supersedes any previous Pressure Operations Manual.

It forms an appendix to both SLB Standard 14, Pressure (SLB-QHSE-S014), and SLB standard 22, Well Integrity (SLB-QHSE-S022).

The POM is intended to set the minimum common standards for all pressure containing and pressure controlling equipment and operations. Any specific local government regulations and/or client requirements that exceed the standards put forth in the Testing Servicing POM shall apply.

It is the responsibility of each operating GeoMarket to determine the additional regulations that apply within its operating area.

The Testing Services POM may be distributed to customers and regulatory authorities only with the prior approval of Testing Services Operations Support. No exceptions to, or deviations from, the requirements set out in this manual are allowed unless duly approved through an approved exemption in QUEST (SLB-QHSE-S010) with final approval being given by Testing Services Operations Support Manager.

The Testing Services POM does not apply to the basic production Testing operations covered by the “Production Testing Services Standard for Land/Rigless Operations” available on InTouch Content ID 6255521 and is applicable only for Production Testing operations which are conducted in a specific domain of application and only where all the following conditions are met:

- Land rig less environment.
- Permanent X-mas tree.
- Well has already flowed in the past.
- Known and stable operating conditions (including: pressure, temperature, rates, fluid composition and fluid properties).
- Well head pressure is less than 9,500 psi.
- Well head temperature is less than 121 degC [249.8 degF].
- Production line pressure is less than 1440 psi.
- $H_2S$ concentration is less than 10%.
- Liquid flow rates are less than 8,000 bbl/d and Gas flow rates are less than 30 mmscf/d.

For all other operations, the POM applies.

### 1.1.1 Competency Knowledge Requirements

All Testing Services Operations and Maintenance personnel should have at least an understanding of Sections 1: Introduction and General Concept, 2: Equipment Quality Control and Administration, 3: Well Integrity, and 9: Testing Services Personnel Qualification and Administration, and Appendix A: Pressure Test Bays & Appendix C: Regional Manufacturing, and Local Remanufacturing and Repair of Pressure Containing or Controlling Equipment. In addition:

- Personnel who hold job planning or wellsite supervisory roles must have an extra, in depth, understanding of section 3: Well Integrity.
- Personnel who work in locations with significant levels of $H_2S$ should also have an understanding of Appendix D: NACE MR-0175/ISO 15156, Second Edition 2009.
- Personnel using or maintaining SWT equipment must have a working knowledge of Section 4: Surface Equipment and Appendix B: Surface Well Testing Pipework and Flexible Hoses.
- Personnel using or maintaining Subsea equipment must have a working knowledge of Section 5: Subsea Safety Equipment.
- Personnel using or maintaining DST equipment must have a working knowledge of Section 6: Downhole Equipment.
- Personnel using or maintaining FSA equipment must have a working knowledge of Section 7: Reservoir Sampling and Analysis Equipment and Appendix E: Reservoir Sampling and Analysis $H_2S$ Standard.

- Personnel performing Perforating Services must have a working knowledge of Section 8: Testing Services Perforating Services.

## 1.2 Definitions

The following is a list of terms and their definitions which are used in this document:

| Term | Definition |
|---|---|
| **Asset History File** | shall contain:<br>• Quality file<br>• Identification, procurement record<br>• Movement Records/FMT<br>• RITE Operation and Maintenance History cards<br>• Records of parts which have been fitted since the equipment entered service.<br>• Spare parts records<br>• Inspection and Test Records<br>• Renewal of Certification<br>• Major repair documentation<br>• NDE Records<br>• 'As build' P&ID file |
| **Barrier Element:** | Any device, object or element such as a fluid column, casing, tubing, tubular crossovers, BOPs, WHE, Flowhead, Lubricator valve, SenTREE, or DST tools, that either alone or in combination with other elements is capable of containing well pressure and preventing the uncontrolled flow of fluids or gases from the formation into another formation, or to the surface or environment. |
| **Common Barrier Element:** | A Barrier Element that is simultaneously part of both the Primary and the Secondary Well Barrier Envelopes is referred to as a Common Barrier Element. If the common element fails, BOTH barriers will fail so Primary & Secondary Barriers are not independent. A Risk Analysis and Mitigation (HARC) shall be conducted prior to starting any well intervention where a common barrier element is used in order to assess the risk of its failure and the potential consequences. An exemption should also be raised against the normal requirement to have two independent barriers and be approved before work commences, in line with the Management of Change and Exemption Standard (SLB-QHSE-S010). |
| **Downhole / DST Equipment:** | All Testing tools run into the well below the casing hanger. (Category 3 equipment as defined in section 1.7 of this manual). |
| **Manufactured Well Barrier Element:** | Any manufactured tool or string component which will be subsequently used as a Well Barrier Element. Specifically for Testing Services, this includes, but is not limited to:<br>• All DST Tools.<br>• SenTREE and EZ Valve tools, and associated items which are run in the hole (Slick Joints, Shear Subs, Retainer and Lubricator Valves, etc). |

- All Crossovers run in the string.
- SCAR.
- DGA (or other gauge Carriers), DLWA, and LDCA.
- Surface Testing Flowheads.
- Gate Valves.

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| **Maximum Allowable Operating Pressure:** | Is equal to the wellsite pressure test value. It must never be exceeded. |
| **Maximum Potential Pressure:** | Is the maximum pressure, flowing or shut in, that a tool at a specific depth in the well could be subjected to during operations. It is determined by calculations in conjunction with the client and is the greater of either:<br>• The maximum undisturbed reservoir pressure minus the pressure of a fluid hydrostatic column between the reservoir and the depth of the tool, where the pressure gradient of the fluid column may be based on the expected reservoir fluid properties, or if a worst case scenario is assumed, the pressure gradient of Methane gas. (0.1 psi/ft).<br>or:<br>• The hydrostatic pressure of any kill or stimulation fluid above the tool plus any pressure which will be applied at surface during Bullheading, Fracturing, or other pumping operations.<br>The reservoir and fluid properties must always be confirmed with the client, and the calculated MPWHP must also be agreed with, and signed off by, the client. |
| **Maximum Potential Well Head Pressure:** | The MPWHP is defined as being the maximum pressure, flowing or shut in, that the surface testing wellhead equipment could be subjected to during operations. It is determined by calculations in conjunction with the client and it is the greater of either:<br>• The maximum undisturbed reservoir pressure minus the pressure of a fluid hydrostatic column between the reservoir and the surface, where the pressure gradient of the fluid column may be based on the expected reservoir fluid properties, or if a worst case scenario is assumed, the pressure gradient of Methane gas. (0.1 psi/ft).<br>or:<br>• The maximum pressure which will be applied or created at surface during Bullheading, Fracturing, or other pumping operations.<br>The reservoir and fluid properties must always be confirmed with the client, and the calculated MPWHP must also be agreed with, and signed off by, the client. |
| **Must:** | See Policy. |
| **Policy** | All statements written in terms of **shall** or **must** are official Schlumberger Testing Policies, for which any deviations or non-compliance must be considered as high risk and therefore requires approval through exemption process by Testing Head Quarters. |

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| **Perforating Services Equipment:** | All equipment such as perforating guns, firing heads, explosive accessories, and also the CIRP system equipment. |
| **Pressure and Analysis Pressure Equipment:** | Fluid Sampling and Analysis Pressure Equipment. All equipment used for capturing samples, both downhole and surface, as well as all well site and laboratory fluids analysis equipment that includes PVT pressure cells. |
| **Pressure Barrier:** | The term “pressure barrier” must not be mixed or confused with other definitions used by customers or other Schlumberger Business segments. Nor must it be confused with the terms "Well Barrier" or "Well Barrier Element" which are defined in POM section 3: Well Integrity. The term pressure “barrier” does not mean that it must be in effect at all times. It must however be operational, installed in the initial equipment rig-up, pressure tested in the direction of flow, and ready to be activated at any time (eg an SSV). |
| **Primary Well Barrier:** | An Element or combination of Barrier Elements that is in direct (Primary) contact with the potential outflow source, i.e. the elements that are normally exposed to formation fluid or gas pressure during well operations. Examples of Primary Well Barriers in place during well testing are shown in Blue in the following illustrations. |
| **Recommended Practices** | Statements written in terms of **should** are to be considered as strongly recommended practices. |
| **Secondary Well Barrier:** | An Element or combination of Barrier Elements which have been designated as the ULTIMATE defense should any of the Primary Barrier Elements fail, and as such prevents an uncontrolled flow from the well to surface or to the environment. It is the LAST and ULTIMATE barrier envelope which provides well Integrity to be activated. It is not necessarily barrier number two in a sequence which may include a number of intermediate Well Barriers between those which are designated as the Primary and Secondary Barriers. Examples of Secondary Well Barriers are shown in Red in the following illustrations. |
| **Shall:** | See **Policy**. |
| **Should** | See **Recommended Practices**. |
| **Subsea Equipment:** | All equipment run in the landing string between the casing hanger and the surface Test Tree. (Category 1.3 equipment as defined in section 1.7 of this manual. |
| **Surface Equipment:** | All testing equipment used at surface which falls under categories 1.2 and 2 as defined in section 1.7 of this manual, plus the associated support equipment (Compressors, Generators, Cabins) and also the Hydraulic or Electrical control equipment for Subsea Equipment. |
| **Quality File:** | The file received from the equipment manufacturer detailing all manufacturing specifications and certification. |
| **Well Barrier Element:** | See **Barrier Element.** |
| **Well Barrier Element Acceptance Criteria:** | In order to qualify an element as being suitable for use, either alone or in combination with other elements, as being capable of containing well pressure and preventing uncontrolled flow of fluids or gases from the formation, it is necessary to define all |

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| | organizational, technical, and operational requirements, guidelines and processes that must be fulfilled. These are known as the acceptance criteria, and are specific for each element. |
| **Well Barrier Envelope:** | The combination of Barrier Elements (as described above) which, when properly deployed and working together, form a containment envelope that prevents the uncontrolled flow of fluids or gases from the formation into another formation, or to the surface or environment. |
| **Well Control:** | A collective expression for all activities that can be applied to contain formation pressure and prevent the uncontrolled flow of fluids or gasses from the formation into another formation, or to the surface or environment. |
| **Well Integrity:** | A quality or condition of a well relating to the structural soundness of the well by application of technical, operational and organizational solutions, such as the use of competent pressure seals, to reduce the risk of an uncontrolled release of formation fluids into another formation, to the surface, or to the environment, throughout the well life cycle to a level which can be demonstrated to be "ALARP" (As Low As Reasonably Practical). Well Integrity is established by implementing and maintaining well barriers to prevent uncontrolled release of fluids from the formation while performing well operations (such as well testing) or while the well is inactive or abandoned. |
| **Wellsite Pressure Test:** | The final pressure test carried out at the wellsite after rig up and before operations to flow the well are commenced. |

# 1.3 Abbreviations

The following is a list of abbreviations used in this document. It does NOT include abbreviations which are Testing Services tool specific names (for example PCT or IRDV) the meanings of which can be found by searching InTouchSupport.com.

| Term | Definition |
|---|---|
| **ABS** | American Bureau of Shipping (a Classification / Certification agency). |
| **AP** | Annular Preventer (Fitted above a Drilling BOP). |
| **API** | American Petroleum Institute. |
| **ASME** | American Society of Mechanical Engineers. |
| **ASTM** | American Society for Testing and Materials. |
| **ATEX** | ATmospheres EXplosives (French). |
| **BHA** | Bottom Hole Assembly. |
| **BOP** | Blow Out Preventer: This term can be used for both Wellhead Equipment (such as used by Slickline, Wireline, or Coiled Tubing) or for a drilling BOP mounted on the top of the well bore casing. |
| **BV** | Bureau Veritas (a Certification Agency). |
| **bpd** | Barrels Per Day. |

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| **BSP** | British Standard Pipe Thread. Sub Divides into two families – BSPP (Parallel Thread) and BSPT (Taper Thread). |
| **BSPP** | See BSP. |
| **BSPT** | See BSP. |
| **CAT** | Compliance Assessment Tool (Compliance Audit Tool in some documentation). |
| **Cat.** | Category. |
| **CE** | Conformite Europeene: Equipemnt which is CE marked meets the standards required by the EU fo use in Europe. |
| **COC** | Certificate of Conformity. |
| **CT** | Coiled Tubing. |
| **CWJ** | Cased Wear Joint. |
| **DBR** | Named after Donald Baker Robinson, DBR is now a Schlumberger Technology Centre. |
| **DNV** | Det Norske Veritas (a Classification / Certification / Standards agency). |
| **DST** | Drill Stem Test. |
| **DVR** | Design Verification Report. |
| **EN** | European Standard. |
| **EU** | European Union. |
| **EUE** | External Upset. |
| **FMT** | Field Material Transfer (The transfer of capitalized items from one location to another). |
| **ft** | foot. |
| **$H_2S$** | Hydrogen Sulphide Gas (Poisonous and Corrosive). |
| **HARC** | Hazard Analysis and Risk Control (Schlumberger Specific document which provides the structure for the process to identify hazards during operations and put prevention and mitigation measures in place.) |
| **HAZOP** | Hazard and Operability Study: is a structured and systematic examination of a planned or existing process or operation in order to identify and evaluate problems that may represent risks to personnel or equipment, or prevent efficient operation. |
| **HPHT** | High Pressure High Temperature. |
| **HQ** | High flowrate (> 30 MMSCF/d Gas or > 8,000 bpd Liquid). |
| **HXT** | Horizontal Christmas Tree. |
| **ID** | Inside Diameter. |
| **In.** | Inch. |
| **IRC** | Independent Review Certificate. |

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| **ISO** | International Organization for Standardization (commonly referred to as “International Standardization Organization” in line with the abbreviation). |
| **JIC** | Joint Industry Council. In This document it refers to a type of taper fitting. |
| **k.** | Thousand. |
| **KW or KWV** | Flowhead or Production Tree Kill Wing Valve. |
| **Lbf** | Pounds Force. |
| **LLV** | Lower Lubricator Valve. |
| **LPI** | Liquid Penetrant Inspection. |
| **LPR** | Power Pipe Ram. |
| **LS** | Lower Shear Ram. |
| **MAOP** | Maximum Allowable Operating Pressure: is equal to the wellsite pressure test value. |
| **MMSCF/d** | Million standard Cubic ft per day. |
| **MPI** | Magnetic Particle Inspection. |
| **MPP** | Maximum Potential Pressure: is the maximum pressure any specific tool in the string could be subjected to, from either downhole reservoir pressure or any pressure applied from surface during Bullheading, Fracturing, or other pumping operations. |
| **MPR** | Middle Pipe Ram. |
| **MPWHP** | Maximum Potential Well Head Pressure: is the maximum pressure, flowing or shut-in, that the wellhead could be subjected to, from either downhole reservoir pressure or any pressure applied from surface during Bullheading, Fracturing, or other pumping operations. |
| **mtf** | metric tonnes force. |
| **NACE** | National Association of Corrosion Engineers. |
| **NC** | Normally Closed. |
| **NDE** | Non Destructive Examination (NDE and NDT are often used interchangeably). |
| **NDT** | Non Destructive Test (NDE and NDT are often used interchangeably). |
| **NPT** | National Pipe Thread: is a U.S. standard for tapered threads used on threaded pipes and fittings. |
| **N2** | Nitrogen Gas (Inert). |
| **OD** | Outside diameter. |
| **OEM** | Original Equipment Manufacturer. |
| **OS** | Offshore Standard (Issued by DNV). |
| **P&ID** | Process and Instrumentation Diagram. |
| **PC** | Schlumberger Product Centre. |

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| **PED** | Pressure Equipment Directive (Issued by the European Commission). |
| **PMV** | Flowhead or Production Tree Production Master Valve. |
| **POM** | Pressure Operations Manual (This Document). |
| **PRV** | Pressure Relief Valve (PRV and PSV are used interchangeably). |
| **psi** | Pounds per Square Inch (can be either pressure or tensile or compressive load). Within the confines of the POM, Pressure expressed as psi (pounds per square inch) always refers to psig. Wherever Pounds per square inch absolute is denoted, "psia" shall always be specified. |
| **psia** | Pounds per Square Inch absolute (psia) is used to make it clear that the pressure is relative to a vacuum rather than the ambient atmospheric pressure. Since atmospheric pressure at sea level is around 14.7 psi, psia = psig + 14.7 for any pressure measurement made in air at sea level. |
| **psig** | Pounds per Square Inch gage (psig), indicates that the pressure is relative to atmospheric pressure. |
| **PSL** | Product Specification Level. |
| **PSV** | Pressure Safety Valve (PRV and PSV are used interchangeably). |
| **PWV** | Flowhead or Production Tree Production (flow) Wing Valve. |
| **QHSE** | Quality, Health, Safety, and Environment. |
| **QOSM** | Quality Operations Support Manager. |
| **RFQ** | Request for Quote. |
| **RIH** | Run (or Running) In Hole (i.e into the wellbore). |
| **RP** | Recommended Practice (Issued by DNV). |
| **SF** | Safety Factor. |
| **SL** | Slickline. |
| **SLB** | Schlumberger. |
| **SRC** | Schlumberger Rosharon Campus (Product Centre). |
| **SRPC** | Schlumberger Riboud Product Centre. |
| **STD** | Standard (Applies to Schlumberger QHSE Standards). |
| **SV** | Swab Valve. |
| **TA** | Type Approval. |
| **TBA** | To Be Advised. |
| **TBD** | To Be Defined. |
| **TC** | Schlumberger Technology Centre. |
| **TH** | Tubing Hanger. |
| **TP** | Test Pressure: is the pressure value at which, by design, the equipment must be submitted to qualify for operational suitability. |
| **TS** | Testing Services. |

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| **TVD** | True vertical depth. |
| **ULV** | Upper Lubricator Valve. |
| **UPR** | Upper Pipe Ram. |
| **US** | Upper Shear Ram. |
| **WBEAC** | Well Barrier Acceptance Criteria: is a document with the definition of all organizational, technical, and operational requirements, guidelines and processes that must be observed or followed in order to ensure the Well Integrity performance of a specific tool which is designated as a Well Barrier Element. |
| **WL** | Wireline. |
| **WHE** | Wellhead Equipment (Slickline, Wireline, CIRP or Coiled Tubing). |
| **WHP** | Well Head Pressure: is the pressure value measured at the wellhead whatever the pressure source. |
| **WP** | Working Pressure: is the equipment's maximum operating pressure rating by design. It must never be exceeded in wellsite operations. |
| **WPT** | Wellsite Pressure Test. |
| **WS** | Well Services. |
| **XOV** | Crossover Valve. |

## 1.4 Marks of Schlumberger

Schlumberger marks used in this document are listed in the Legal Information section.

## 1.5 Communications

Questions regarding the Testing Services Pressure Operation Manual (POM) should be submitted to Testing Services Operations Support via established channels.

## 1.6 General Concepts - Fundamentals of Design

For each material used for pressure containing parts, a “Tensile Strength” value and a “Yield Strength” value are defined. An applied stress above the Yield Strength will cause permanent deformation and eventual rupture of the material. In cylindrical containers subject to an internal pressure “P” (absolute or differential), the applied stress due to pressure is approximately proportional to “P”. The total combined stress on equipment is a combination of the tensile loading and pressure loading, plus stress risers caused by component geometry. When operating at elevated temperatures, the Yield Strength and Tensile Strength are reduced.

For Surface well testing equipment where the Design method is “Yield based” such as with API 6A, at **no time**, whether while “pressure testing” or “operating”, shall the combined stresses reach or exceed a magnitude that causes the Yield Strength to be exceeded. Calculating the combined stresses is one of the critical planning stages of any completion application design.

For Subsea Test Trees and related equipment where the design method is "Strain based", such as ISO 13628-7, to provide a better load capacity model, the above statement does not apply.

Both API 6A “Yield based” and ISO 13628-7 “Strain based” design approaches as valid, as long as the application of hardware is valid for the calculation method selected.

## 1.6.1 Safety Factor

Testing Services operations are often performed with equipment that is specified by different and sometimes conflicting, industry accepted design criteria. Specifically, wellhead equipment, Subsea equipment and well testing equipment ratings are validated by industry standards that include the safety factors required for all normal operating conditions. Perforating, DST tools and accessories have specifications which include nominal ratings with low to no design safety factor and it is left to the field personnel to select suitable safety factors to apply for each specific application. Following is an example to illustrate variable safety factors:

**Table 1-1: Safety Factors**

| **Subsea Test Tree (SenTREE 7)** | | **5-1/2 in. VAM ACE Landing String and Crossovers** | |
|---|---|---|---|
| Working Pressure | 10,000 psi @ 440,000 lb and 175°C | Burst Pressure | |
| Test Pressure | 15,000 psi @ 0# | Max. Proof Pressure | (80% of burst) |
| Tensile Strength | 1,000,000 lb @ 0 psi | Tensile Strength @ yield | |
| Safety Factor required for DP vessel well test with $H_2S$ and $CO_2$ | N/A | Safety Factor required for DP vessel well test with $H_2S$ and $CO_2$ | 1.6 for Tensile Loads |

| **Subsea Test Tree (SenTREE 7)** | | **5-1/2 in. VAM ACE Landing String and Crossovers** | |
|---|---|---|---|
| Safety Factor required for DP vessel well test with $H_2S$ and $CO_2$ | N/A | Safety Factor required for DP vessel well test with $H_2S$ and $CO_2$ | 1.25 for Pressure Loads |
| Safety Factor required for DP vessel well test with $H_2S$ and $CO_2$ | N/A | Safety Factor required for DP vessel well test with $H_2S$ and $CO_2$ | 1.25 for Combined Loads |

Pressure-containing equipment is required to perform with a sufficient margin of safety to allow for several variables and uncertainties, such as materials' yield strength and tensile strength variations, approximations in design calculations, stress concentrations, machining tolerances, shock loading, abuse and misuse in the field. Such margin of safety is embodied in a "Safety Factor" (SF), defined as:

$$SF1 = \frac{\textit{Minimum Yield Strength}}{\text{Design Working Stress}}$$

$$SF2 = \frac{\textit{Minimum Tensile Strength}}{\text{Design Working Stress}}$$

For example, a Safety Factor (SF1) of 2 means that the Design Working Stress is only half of the minimum yield strength of the materials used. The value of SF is imposed by design codes, industry rules, government agencies or internal manufacturers' regulations. Its value will also be a function of the risks presented by an equipment failure in terms of personnel safety and assets damage. The SF may be applied either before the equipment rating is specified (as in wellhead equipment) or by the application AFTER the equipment rating is specified (as in Completion Equipment). Therefore, equipment under pressure coming in contact with personnel will be designed with a larger safety factor than downhole tools whose failure will not result in direct injury or loss of life.

## *1.6.2* Working Pressure (WP)

The choices of SF and of the material's yield strength (or tensile strength) define the Working Pressure rating (WP) of the equipment, usually expressed in psi (pounds per square inch).

The WP is the maximum allowable pressure never to be exceeded during field operations of the equipment.

### 1.6.3 Test Pressure (TP)

To ensure proper operation at WP, pressure-containing equipment is tested at defined time intervals, at a maximum pressure greater than or equal to WP, defined as Test Pressure (TP). The value of TP is recommended by the manufacturer, and often stipulated by industry codes and governmental agencies regulations. API and ASME specify TP = 1.5 x WP for most of the surface equipment concerned by this manual. See Table 4-1: Test Pressure for Surface Testing Equipment for details. For downhole tools, Test Pressure is generally equal to Working Pressure.

However sampling tools which successfully capture sample return to surface under pressure. Therefore they become effectively Surface Equipment before the samples are transferred into shipping cylinders.

For downhole tools, Test Pressure is equal to Working Pressure except for sampling tools which return to surface under pressure, the Test Pressure for these sampling tools is 1.5 times working pressure.

For SubSea Landing String tools, Test Pressure is equal to 1.2 times the working pressure (WP), unless a major pressure containing or load bearing component has been repaired, welded or replaced since last Major Survey or FAT in which case a body pressure test according to the design will be required at Test Pressure, normally 1.5 times the working pressure (WP).

### 1.6.4 Temperature Rating

A minimum and maximum temperature rating shall be defined for all pressure containing equipment.

## 1.7 Categories of Pressure-Containing Equipment

Usually, when dealing with flowing hydrocarbons, the well stream pressure is reduced in stages. The process equipment is designed in sections, with different pressure ratings. The WP of the weakest component within a section gives the section its overall pressure rating. Each section of equipment shall either be selected to withstand the maximum pressure that can be exerted upon it under worst-case conditions or shall be protected by a suitable pressure venting/relieving device.

The Wireline Pressure Operations Manual (InTouch Content ID 3046294) primarily addresses the equipment shown pictorially in Figure 1-1: Categories of Pressure-Containing Equipment as being in Category 1.1.

This manual, the Testing Services Pressure Operations Manual, primarily addresses the equipment shown as being in all the other categories.

Both manuals cover hardware used for containing and controlling well pressure and/or well flow.

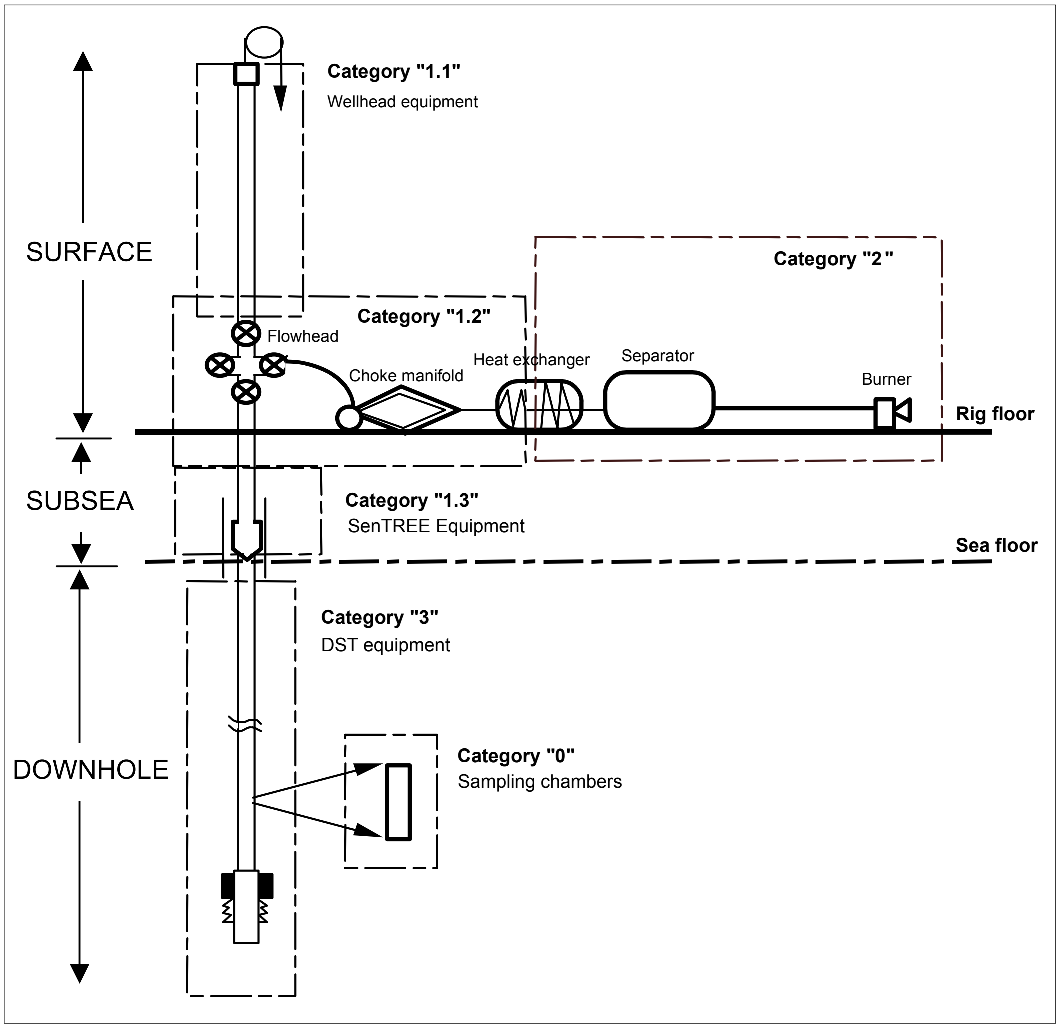


**Figure 1-1: Categories of Pressure-Containing Equipment**

### 1.7.1 Category 1

This is equipment submitted to the **full wellhead pressure** during normal operations. A failure of such equipment can have severe consequences on personnel. With the exception of Subsea Test Tree (SSTT) Shear Joints the minimum Safety Factor is equal to 1.5. The minimum safety factor for SSTT Shear Joints is 1.25.

The equipment can be divided into three sub-categories:

- **Category 1.1:**

  Surface equipment designed to handle only internal pressure (e.g., Wireline / Slickline pressure control equipment and CIRP deployment Stack.)

- **Category 1.2**:

  Surface equipment designed to handle and control full wellhead pressure and flow from the flowhead or wellhead to the process equipment. (e.g., flowheads, choke manifolds, PhaseTester, test lines, etc.)

- **Category 1.3:**

  Subsea equipment designed to handle internal pressure and flow and located between the sea floor level and the flowhead. (e.g., Subsea trees, fluted hanger, slick joint).

The most relevant codes for Category 1 are:

- API Specification 6A.
- API RP 14 C.
- API Specification 17G / ISO 13628-7.
- NACE Standard MR-0175.

### 1.7.2 Category 2

This is surface pressure vessels, piping equipment and pumps handling pressure and flow down stream of the wellhead equipment (flowheads, choke manifolds, Xmas tree). Failure of such equipment could have catastrophic results on personnel. The Safety Factor is usually 2.0, but can be as high as 4.0 (e.g., for a separator vessel, containing a large volume of gas under pressure).

The most relevant industry codes are:

- ASME section VIII for pressure vessels
- ASME B31.3/API RP14E for production piping.

Heaters and Steam Exchangers are covered by API Specification 12K and Tanks by API Specification 12F.

## 1.7.3 Category 3

This is drill stem test (DST) and Tubing Conveyed Perforating (TCP) equipment located below the ground level or the sea bed subject to formation and well bore pressure. The equipment handles pressure and flow.

**Category 3.1:** Subsurface Safety Valves are designed to handle internal pressure and flow and are typically located near the surface and require a high level of quality control and certification. The most relevant codes for Category 3.1 are:

- API Specification 14A/14D

**Category 3.2:** Other downhole equipment.

It is recognized that failure of Category 3.2 equipment would not, in normal circumstances, directly affect personnel safety, but could have direct consequences on the well itself. Due to the fact that this equipment OD is limited by the well construction and that the ID must be as large as possible, the available metal thickness is limited and Safety Factors are usually 1.1 < S.F. < 1.25. Note that the WP is often defined as “maximum differential.” Caution should be exercised with tools containing atmospheric chambers where full hydrostatic pressure must be considered.

Other elements requiring special attention are pre-charged chambers containing nitrogen under pressure.

Although no specific industry codes have been defined for downhole test tools, relevant codes are NACE Standard MR-0175 for $H_2S$-resistant material, API Specification 5CT and Specification 5D for Tubulars.

## 1.7.4 Category 0

This is an intermediate class of equipment covering downhole sampling chambers. This equipment does not represent a risk to personnel downhole, but falls into Category 1 when brought back to surface. Safety Factors vary from 1.2 to 3.0.

Relevant industry code for the sampler pressure vessel design is ASME/ANSI B31-3.

Specific regulations apply for the certification of sample receptacles and for their transport.

# 1.8 Service Type

The service types for pressure-containing equipment are defined by the following environmental parameters:

- Minimum Design Temperature.
- Maximum Operating Temperature.
- Type of fluid: $H_2S$ or Standard (No $H_2S$).

  Service types for pressure-containing equipment are listed in Table 1-2: Service Types.

**Table 1-2: Service Types**

| Service Type | Environmental Parameters |
|---|---|
| $H_2S$ Service (NACE MR-0175) [1] | - When partial pressure of $H_2S$ exceeds 0.05 psia and the total pressure is above 65 psia or the concentration exceeds 150,000 ppm<br>- or in a corrosive environment. |
| Standard Service (or General Service) | When no free hydrogen is present. |
| Minimum Design Temperature:<br>- Standard temperature:<br>- North Sea Conditions:<br>- Arctic Conditions: [2] | <br>- 0°C [32°F] as per North Sea requirements or - 20°F [-29°C] in compliance with ASME<br>- The Minimum Design Temperature is **- 20 degC [-4 DegF]**<br>- The Minimum Design Temperature is **< - 20 degC [-4 DegF]** |
| Maximum Operating Temperature | This temperature is defined for each equipment. |

[1] NACE MR-0175 is in Appendix D

[2] Arctic equipment shall use special steel, resistant to embrittlement in extreme cold and special elastomers.

# 1.9 Pressure Testing of Equipment

## 1.9.1 Types of Pressure Tests

All pressure test operations are to be carried out with Permit To Work in place and Pre-Job Safety meeting prior to proceeding.

There are different types of "pressure tests":

- **Design qualification and certification pressure tests**. These tests are mostly carried out on prototypes or pilot series at engineering or at certifying agencies' facilities. Their purpose is to verify design criteria.

- **Factory acceptance, verification and equipment certification pressure tests**. Proof tests are carried out on production tools by the manufacturer or by certifying agencies, as a manufacturing quality control routine step or as part of a certification procedure.

- **Regular pressure tests**. These tests are carried out at reception of the equipment and at regular intervals throughout the useful life of the equipment. Their purpose is to verify the equipment's integrity and its capability to function.

  The frequency of regular pressure tests is determined by maintenance and qualification requirements specific for each category of equipment. The frequency can also be subject to compliance to local authority regulations or contractual agreements. These tests are covered in subsequent sections of these guidelines, together with specific instructions.

- **Hydrostatic Body Pressure Test**. This is carried out to a Test Pressure (TP) defined for each equipment type. The equipment is not operated at this pressure, nor are valve seats tested. In-line valves and BOP rams, etc., must be in a partially opened position. Pressure Tests above WP must only be carried out in a Test bay meeting the requirements of Appendix A.

  Hydrostatic body recommended testing routine consists of a primary pressure-holding period, followed by pressure reduction to zero and a secondary pressure-holding period. Duration of each period is determined by industry codes or certification regulations.

- **Operational Pressure Test**. The assembled equipment is pressurized to Working Pressure (WP), moving systems are operated and valve seats are tested.

- **Wellsite Pressure Test**. A wellsite pressure test shall be carried out after setup/rig-up, prior to starting operations and at regular intervals for long-duration operations.

  For wellsite pressure tests, adequate warnings must be posted in the area where equipment is tested and all unnecessary personnel must clear the test area. "Lines of fire" must be identified (valves, pressure ports, fittings) and personnel carrying out the test must stand clear of them.

  The Wellsite Test Pressure is related to the Maximum Potential shut-in Wellhead Pressure (MPWHP), as defined further in these guidelines for each type of equipment and agreed upon by the client.

  The Wellsite Test Pressure equals the Maximum Allowable Operating Pressure (MAOP).

The Working Pressure ratings (WP) of the Schlumberger equipment or of any client's equipment directly in communication with it must never be exceeded.

The following equation must be verified:

WP of Schlumberger or Client Equipment > Wellsite Test Pressure = MAOP > MPWHP

In the event that a number of items are to be tested together, the MAOP shall be limited by the lowest of the individual components Working Pressure ratings.

RSA laboratory pressure tests, performed in the laboratory require a job-specific approved HARC to be in place. Adequate warnings must be posted in the area where the equipment is being tested, and all unnecessary personnel must evacuate the area. "Lines of fire" must be identified (valves, pressure ports, fittings) and personnel carrying out the test must stand clear of them.

## 1.9.2 Pressure Testing with Liquid: (Hydrostatic Tests)

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**Note**

Pressure testing is a hazardous operation. The risk is proportional to the accumulated energy, linked to the fluid compressibility and to the volume and elasticity of the containing envelope.

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At high pressure, even water can store destructive energy. For risk evaluation, 95 L of water at 15,000 psi are equivalent to one liter of gas at the same pressure.

Fine jets of high-pressure liquid can be harmful or fatal.

Water based test fluids or other specially designed non-volatile, non-flammable, low compressibility testing fluids shall be used. Water based fluids with suitable corrosion inhibitors and antifreeze additives such as ethylene glycol are typically used.

Pressure testing equipment in Categories 1 and 2 with diesel, well fluids or other flammable fluids is forbidden. Pressure testing equipment in Category 3 with diesel is forbidden, unless performed under the conditions specified in Section 6.5: Pressure Testing. Only Testing Operations Support can grant an exemption to this rule.

There is often some trapped air or gas in equipment, increasing the fluid compressibility. Before being pressure tested, equipment must be thoroughly flushed to eliminate any trapped air or gas.

In case of tests under elevated temperature, the risk of overpressure due to a sudden vaporization of the test liquid must be considered.



### 1.9.3 Pressure Testing with Inert Gas: (Gas Test)

Testing with gas is strongly discouraged due to the increased safety risk of a compressed gas when compared to standard hydrostatic fluids.

Pressure testing using an inert gas should therefore be limited to:

- Special requests from the Client.
- Procedures specifically called for in the equipment maintenance instructions.
- Non-routine troubleshooting, when the quality of the test cannot be achieved using liquids.
- Specific fluid and rock analysis equipment, from which pressure test liquid cannot be completely drained after the test.

General rules to observe if testing with gas:

- Gases are very compressible and store large amounts of energy.
- Only a non volatile (inert) gas (e.g nitrogen or helium) may be used.
- Nitrogen of the required purity must be used: less than 0.5% oxygen content is acceptable. Nitrogen gas bottles can contain some oxygen gas, which could create an explosive mixture when coming into contact with hydrocarbons or hydrocarbon derived substances such as grease. All nitrogen bottles shall be checked for oxygen contamination before use.
- In no case, can the pressure test with gas exceed the rated WP of the equipment being tested.
- Equipment to be gas tested must first be pressure tested to at least 1.2 times the pressure required for the gas test with a non-compressible (Hydrostatic) fluid.
- The test shall be conducted at ambient temperatures in a pressure test bay.
- The equipment must be completely submerged in a water pool as a means of leak detection.
- In all cases where gas testing is planned a HARC must be performed and documented, and a predefined set of procedures written before the work commences.

**Danger**
Potential Severity: Catastrophic
Potential Loss: Assets
Hazard Category: Pressure

When bleeding off the pressure after completing a pressure test with gas, it is necessary to perform a staged pressure reduction process to prevent seal damage due to rapid (explosive) decompression.
This is done by bleeding down the Nitrogen or other inert gas from test pressure to between 1200 and 1000 psi and then holding for 10-15 minutes.
The remaining gas should then be bled off at a uniform rate of approximately +/- 100 psi every 10-15 minutes.
When the volume of the chamber exposed to Nitrogen pressure is very small making this bleed-off procedure difficult to observe (e.g. function/pressure testing DST tools atmospheric chambers), the Nitrogen pressure should be bled off as slowly as practical. If elastomers are to be exposed to gas at high pressure (above 1100 psi) more than 20 min. the bleed off schedules shall be respected.

**Note**

It may be necessary to have the testing conducted by a third party who have the appropriate facilities and equipment for such testing .

**Danger**
Potential Severity: Catastrophic
Potential Loss: Personnel
Hazard Category: Pressure

Threaded plugs, drain valves, compensating pistons sealing gas pressure can become deadly projectiles when coming loose.

**Caution**
Potential Severity: Light
Potential Loss: Personnel
Hazard Category: Pressure

Avoid bleeding-off high-pressure gas at too fast a rate through a small orifice to prevent excessive noise.

- Personnel:
  - Only certified, experienced personnel are allowed to carry out gas pressure testing.

– Particular care must be exercised when disassembling equipment containing or having contained gas, to avoid unscrewing pieces that could trap remaining gas pressure. If any thread is tighter than normal, trapped pressure must always be assumed and adequate precautions taken.

– Access of nonessential personnel to the area where the test is carried out must be restricted.

# 1.10 Certification

## 1.10.1 Quality File

Testing Services Assets, re-useable service tools and well testing equipment shall have a quality file. Perforating and auxiliary downhole equipment products will have a defined quality plan based upon client requirements.

The initial quality file is supplied by the equipment manufacturer and the contents of the quality file are defined in section 2.3.1: Asset Certification and Traceability. The quality file shall subsequently be augmented with Material traceability certificates for any structural component replacement or repair, and any other applicable records as specified elsewhere in this manual, by the location owning the equipment at the time the components were replaced or repaired. Material traceability information for both structural and non structural replacement parts shall be recorded in RITE so as to become part of the history file as defined in section 2.2: Asset History File.

## 1.10.2 Equipment Certification

“Certification” for pressure-containing equipment is very often requested by clients or dictated by regulations. The term “certification” is used with a wide variety of meanings. A certification document can be issued by the service company operating the equipment (in-house certification), by the manufacturer (sometimes called manufacturer survey) or by a third party. Certifications state that the components, equipment or assemblies meet the stated requirements.

Third party certification documents are issued by recognized certifying agencies such as Bureau Veritas (BV), American Bureau of Shipping (ABS), Lloyds, Det Norske Veritas (DNV) or other bodies deemed to be competent by a statutory certifying authority.

Certifications are issued against published industry codes and regulations (e.g., API specifications) or Government Authorities Standards (e.g., UK Statutory Instruments, Texas Railroad Commission Rules, Norwegian Petroleum

Directorate Regulations, etc.). Definition and names of the various certificates differ among different statutory authorities and certification agencies. There are two kinds of certificates:

- Design approval certificates:
  - **Type Approval (TA)** is a general approval based on design assessment and qualification of the first equipment of the same type having a complete manufacturing file. It applies to all equipment built according to the approved file.
  - **Independent Review Certificate (IRC)** is similar to a Type Approval and is an assessment by a competent body verifying that the specifications for manufacture of an assembly meet the requirements of the authorities' regulations and industry codes.
  - **Design Verification Report (DVR)** is a design assessment similar to the one for TA. It can cover only one specific asset, identified by a unique serial number or be applicable to small series manufacturing. Testing Services equipment is often covered by DVR's.
- Manufacturing survey certificates:
  - **Certificate Of Conformity (COC)** certifies that a specific asset or assembly, identified by its serial number, conforms to the approved design and manufacturing file. It is issued following a detailed survey of the asset. It entails, among other steps, witnessing tests, checking material certificates and checking that all documentation (quality file) represents the "as built" status of the item surveyed.
  - **Product Certificate** is similar to a COC except that it is issued by the Schlumberger Product Centre which is responsible for the manufacture of the equipment detailed on the certificate under an agreement with the certifying agency.
  - **Test and inspection reports** certify to the performance of tests (pressure, load, lifting capacity, etc.) according to standards and to the validity of test results. Under this heading are also included reports from companies performing dimensional control or nondestructive testing (e.g., Magnaflux). Their service operators must have a recognized certificate of competence, such as a guild certificate. Such reports are, for instance, issued when a major survey is performed. See Section 2.5: Asset Maintenance - RITE.

The manufacturer issues manufacturer's certifications itself without third party verification. Their validity is enhanced if the issuer holds a QA certification; for instance, SRPC and SRC are certified per ISO 9001.

SRPC has an agreed Manufacturing Survey Arrangement (MSA) with DNV. This is an agreement covering all testing products having a DNV Type Approval or Design Verification Report and giving SRPC authorization to mark the products with the DNV stamp and issue directly a COC that is subsequently endorsed by DNV.

In-house certifications are produced by the company operating the equipment and document the regular performance of routine quality assurance tests and inspections according to company regulations.

### 1.10.3 Traceability

Field locations must keep complete and up-to-date records of any modification, alteration or repair to pressure-containing equipment. These records are critical to maintaining traceability and must be kept in the equipment Quality File.

Traceability is often a part of certification requirements. The term “traceability” means the ability for parts to be identified as to their origin, manufacturing process and materials used. Depending on the level of certification and on the codes/specifications, traceability may be required to a “job lot” (batch) or to a particular “heat treatment”. Traceability requirements for certified items can extend to any replacement parts used in maintenance and repairs.

The traceability requirements for equipment which is designated as being a Well Barrier Element extend to the individual identification of certain components which have been defined during the tool design as being “Critical” to its integrity by batch or serial number. These parts have individual certification and traceability documentation which may include a component specific CoC or Product Certificate. If any of these parts are replaced or repaired/remanufactured (as described in POM section 2.4.3: Replacement of Parts or Equipment Repair / Re-Manufacturing, the details must be recorded both in a RITE Work Order and in the Equipment Quality file. The details must include the serial number or marking details of both the part which was removed, along with its fate (i.e. scrapped or used for another tool), and the serial number or marking details of the part newly installed, along with the date, the name of the person who performed the exchange, and a copy of the certification documentation of the new part.

### 1.10.4 Certification Renewals

Certifications have finite time validity for pressure-containing equipment. Most certifying authorities require that third party certifications be renewed every five years, although it can be required more frequently in certain cases. For sample receptacles, this time is often reduced to two years.

Renewal of certification is granted after the equipment has passed a major survey, consisting as a minimum, of NDE inspection, thickness and crack tests, hydrostatic body tests, hydrostatic tests, operational tests (if applicable) and Quality File reviews. This survey is carried out or witnessed by certifying agencies' personnel.

## 1.10.5 Personnel Certification

There are no published industry codes specifying certification procedures for personnel operating pressure-containing equipment. It is therefore the service company's responsibility to establish its own procedures, training programs and qualification steps. Authorities and clients often require proof of such in-house certification. Testing Services in-house certification requirements and certification procedures for personnel are detailed in Section 9: Testing Services Personnel Qualification and Administration.

All crews operating equipment containing pressure shall be "qualified" to carry out pressure operations according to the Schlumberger in-house certification procedures defined in this manual. Personnel Qualification requirements are defined for each discipline.

# 1.11 Section 1 Revision History

For more details see Appendix F.

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**Warning**

Potential Severity: Serious
Potential Loss: Security
Hazard Category: Human

The controlled source document of this manual is stored in the InTouch Content ID 3045666. Any paper version of this standard is uncontrolled and should be compared with the source document at time of use to ensure it is up to date.

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# Equipment Quality Control and Administration

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# 2 Equipment Quality Control and Administration

## 2.1 Scope and Responsibility

This section defines the standard procedures to purchase, control and track all Testing Services Equipment and parts used to contain or to control well pressure and flow.

The **Quality Operations Support Manager** is responsible for implementation and control of these procedures within the GeoMarket.

### 2.1.1 Location Audit

To ensure that the GeoMarket is fully aware of the location status, both for equipment, personnel and operating procedures, the Quality Operations Support Manager (QOSM) shall conduct location Compliance Assessment Tool (CAT) audits annually.

The Location Manager shall conduct an audit using the same tool every 6 months. The most recent CAT performed by the location manager and uploaded in QUEST shall be the basis for the GeoMarket audit.

The CAT shall also be used if the location is subjected to an external audit.

A Testing Services Headquarters or Area representative might conduct the external audit.

The CAT template can be downloaded from QUEST.

## 2.2 Asset History File

Each location is responsible for keeping complete inventories, maintenance records and certification records when required for all items of equipment covered by this procedure. These records shall be organized into Asset History Files, preferably by sets of equipment and managed through RITE.

**Table 2-1: Asset History File Contents**

| | |
|---|---|
| Quality File, including certification and traceability records (as required) | Delivered by the supplier |
| Identification, procurement records | Updated by the Geomarket/Location |
| Equipment, procurement and movements records (FMT and/or invoices) | Updated by the Geomarket/Location |
| RITE history cards or computer history records | Updated by the Geomarket/Location |
| Spare parts traceability records (if required) | Updated by the Geomarket/Location |
| Inspection and test records, annual survey (Q-check) | Updated by the Geomarket/Location |
| Renewal of certification (as required) | Delivered by certifying authorities |
| Major repairs documentation | Delivered by repair shop |
| Nondestructive Examination (NDE) records | Delivered by NDE contractor |
| ‘As Build’ P&ID file | Delivered by the product centre and updated by the Geomarket/Location |

Certification and material traceability is normally required for pressure-containing and pressure-controlling parts and other structurally relevant parts.

The frequency of regular inspections, annual survey Q-checks, re-certifications, etc., is defined in this manual for each category of equipment.

The location shall maintain a schedule for all necessary inspections and certification renewal for each set of equipment.

Records to be kept for NDE inspection:

- Type of inspection (visual, Magnaflux, X-ray, etc.)
- Operator proficiency certificate
- Date of inspection
- Name of inspector and signature of inspector or supervisor

## 2.3 Procurement

All pressure-containing and pressure-controlling equipment including crossovers and surface piping shall be purchased exclusively through Schlumberger Product Centers.

**Note**

For the purpose of purchasing, the definition of Schlumberger Product Centres includes SRPC External Sales and the Regional Manufacturing process controlled by the RTST Rapid Response Crossover group as described in Appendix C.

Testing Services Technology Centers are responsible to ensure that purchasing and manufacturing specifications are established and distributed to approved vendors.

Testing Services Rapid Response shall approve special requirements and purpose-built systems. The request for approval shall include complete purchasing specifications.

Spare parts and replacement subassemblies for pressure-containing and pressure-controlling equipment should be purchased from the Technology Center responsible for the manufacture of the equipment or from the supplier specified in the equipment file. They may also be purchased from an alternate supplier if approved by a Testing Services Technology Center.

**Note**

Fake or replica pressure containing items have been found to be commercially available in some countries. The above controls are necessary when ordering spare parts to ensure that no fake or replica items, or parts of substandard quality, without proper traceability, or which have reduced safety factors entering the Schlumberger supply chain.

## 2.3.1 Asset Certification and Traceability

All new equipment shall be delivered to the field or laboratories with their associated Quality Files.

Quality Files will include any or all of the following:

- The listing of all components suitably identified (assembly part number, code, serial numbers, grade, OD, service type, rated test pressure, working pressure).
- A general assembly drawing with Bill of Materials and list of recommended spare parts, if not routinely available in Manufacturers Manuals.
- Mechanical specifications (as a minimum tensile strength) of any load-bearing equipment.

- Design approval certificates (IRC, DVR, TA) if applicable.
- Certificate of Conformity to purchasing specifications and to applicable design standards and codes (API 6A, NACE MR-01-75, etc.).
- Material traceability certificates as required.
- Integrity (hydrostatic) and operational pressure test certificates.
- PSV (Pressure Safety Valve) calibration certificates.
- Welding inspection and welders' certificates when applicable.
- Lifting specifications and certifications as applicable.

The Pressure Test certificates shall include:

- Pressure test date and test pressure.
- Test type (body, operational) and test fluid.
- Asset identification.
- Name of person performing the test.
- Signature of person performing or supervising the test.

At a minimum the quality file must contain a manufacturer's pressure test certificate, an acceptance inspection certificate, and proof of regular pressure testing according to survey procedures. This documentation is to be augmented as required by local regulations and/or client's contractual requirements.

Additionally, for equipment which is identified as being a "Well Barrier Element" (as defined in POM section 3: Well Integrity), the Quality File must contain any relevant test and inspection reports, Design Verification Reports, and a Certificate of Conformity or Product Certificate (all as described in POM section 1.10.2: Equipment Certification).

To be in accordance with API 6A, manufacturers must retain an original or a duplicate original of all quality and traceability records for a minimum of 5 years. The specification used by Schlumberger Product centres requires the manufacturer to keep the records for an increased period of 15 years, and a copy will also be kept by the product centre responsible for the manufacture of the equipment for an equivalent length of time. Duplicate originals or originals of these documents shall be filed in the location which owns the equipment, be retained over the lifetime of the equipment, and moved with the equipment if it is permanently transferred between locations.

## 2.3.2 Rented Equipment

Well Barrier Elements as defined in Chapter 3: Well Integrity (e.g. Flowheads, DST tools, Subsea tools, below flowhead/DST/Subsea crossovers etc...) must exclusively be supplied by Schlumberger; it is NOT permitted to rent any well barrier elements. Any deviation from this rule will require an exemption to be approved only by Testing Services Headquarter.

Pressure Containing or Pressure Controlling equipment not defined as Well Barrier Elements (e.g. Steam Exchangers, Tanks…) may be rented provided the rental company has been positively assessed as defined in Section 2.3.2.1: Rental Equipment Supplier Management. The rental company shall provide a complete Quality File with Type Approval (TA) or Design Verification Review (DVR), Certificate of Conformity (COC) and Data Book similarly to the Quality File provided by the Product Center for Schlumberger equipment of the same type. The Table of Content of an equivalent Schlumberger Asset Quality File can be used as a check list to ensure completeness of the rented equipment Quality File.

Other equipment not Pressure Containing/Controlling related (e.g. Compressors) may also be rented assuming the rental equipment meet the same standards applicable to Schlumberger equipment (Traceability, Lifting certifications, Equipment age, etc...). The rental agency shall supply an in-house certificate-guaranteeing conformance to the standards, showing results of latest tests and various inspections. Integrity and operational test shall be not older than three months at the time of equipment delivery to Schlumberger and issued at the same time as the equipment.

### 2.3.2.1 Rental Equipment Supplier Management

Rental equipment supplier shall be approved by Supply Chain.

For the rental of Pressure Containing or Pressure Controlling Equipment, the Area Equipment Assurance functions shall perform a technical evaluation of the rented product and assess the supplier maintenance and management process. This evaluation process shall be performed either by competent Area staff, certified third party or alternatively with the assistance of the Product Centre through an InTouch ticket followed by an RFQ.

For the rental of other equipment (e.g. Compressors), the Geomarkets shall perform a similar technical evaluation of the rented product and assessed the supplier related maintenance and management process.

## 2.3.3 Client Supplied Equipment

Equipment given by the client to Schlumberger Testing Services for use shall follow all identification, maintenance and qualification requirements as for Schlumberger-owned equipment. Any substandard equipment shall be replaced.

Clients shall remain responsible for equipment supplied occasionally to Schlumberger for operations in clients' wells and on clients' wellsite. If the equipment does not conform to these guidelines, the client shall be made aware of the reasons for nonconformance and an exemption must be raised (with a HARC attached). Schlumberger Testing personnel shall not operate equipment without documented proof of compliance to the minimum required Schlumberger standards. The Schlumberger wellsite supervisor shall consult with line management if in doubt of the equipment compliance.

Any client owned or supplied equipment which is managed or maintained by Schlumberger Testing Services should be created in RITE by the location with the “Unit FA” field of the RITE equipment card set in Figure 2-1: Client Owned.


**Figure 2-1: Client Owned**

The management and/or maintenance requirements of any client owned or supplied equipment, along with the Schlumberger and client responsibilities, should be clearly defined in a contract.

## 2.3.4 Non Schlumberger Contracted Service Company Equipment

For certain types of operation, it will be necessary to connect Schlumberger supplied equipment to pressure containing or controlling equipment which has been supplied by other service companies who have been contracted directly by the Client rather than though Schlumberger as a 3rd party contractor.

In these circumstances, it is the responsibility of the Testing Services supervisor to request the design specifications and certification status of the equipment concerned either through the client, or directly from the Service Company companies who are supplying the equipment.

No job may proceed unless the requested information has been received. The design specifications must be compared to the specifications of the Schlumberger equipment to which it will be connected. Special attention must be paid to the pressure ratings, tensile capacity and ID and OD measurements (as applicable) to ensure that they match the specifications of the Schlumberger equipment. Where equipment from another service company is included in the string, the design specifications must be included in the string diagram.

The certification records of the equipment must be reviewed to ensure that they match, or are superior to, Schlumberger POM requirements. If the records do not meet POM requirements then the issues must be raised with the service company concerned and, where possible, the records must be updated or improved. If it is not possible for the records to be improved to meet POM specifications then a HARC must be performed and an exemption raised. The client must also be made aware of the issues in writing as far in advance of the job as possible and a receipt acknowledgement requested.

## 2.4 Asset Management

Records shall be precise and comprehensive to permit tracking of each individual item and relating it to its manufacturer's Quality File, service and maintenance history. RITE is the business system used for asset management.

### 2.4.1 Equipment Identification and Marking

Each single item of pressure-containing equipment shall be stamped on a structurally non-critical area or on a permanently attached metal band, ring or plate, with the following information:

- Manufacturer identification code or Schlumberger asset code.
- Serial number or item number and manufacturer's part number for non-assets.
- Service type.
- Working Pressure (Compulsory for all equipment except downhole equipment which is marked with a Schlumberger Asset Code).
- Test Pressure Rating (Compulsory for Sample bottles, optional for other equipment).

- Date of manufacture.

Identification stamping on bodies shall be on low-stress areas and use low-stress stamps (dot, vibration, round V). Sharp V stamping shall be avoided. For fixed assets or items in an assembly that is a unique fixed asset, the identification shall correspond to the one used in the fixed assets records.

To easily identify surface equipment as to its Schlumberger assigned Working Pressure rating and service type, a color-coding shall be used in addition to the permanently stamped identification (see Table 2-2: Pressure-Containing Testing Services Surface Equipment Color-Coding).

**Table 2-2: Pressure-Containing Testing Services Surface Equipment Color-Coding**

| Working Pressure (psi) | Whole body color blue with color band: |
|---|---|
| 1500 | Light blue |
| 2500 [1] | Yellow |
| 5000 | Red |
| 10,000 | Black |
| 15,000 | White |
| 20,000 | Brown |

[1] 4 in. 602 SCH 80 is rated 2300 psi but uses yellow band.

Another recommended quick identification system uses colored adhesive tape with overprinted text. Letters should be at least 20 mm high for good visibility. Such tapes are available as commercial products from specialized suppliers for pipelines and chemical treatment plants or from some wellhead equipment suppliers. (For instance, Elmar supplies printed tape labels on flexible aluminum covered with Mylar, showing good adherence and durability).

Surface equipment crossovers shall carry the whole body color blue with the proper color band and overall Working Pressure rating of the lowest rated connection or other part. For example, a 3 in. 1502 by 3 in. 1002 surface piping crossover will have the Schlumberger-assigned WP rating of the lesser 3 in. 1002 connection of 5,000 psi. The whole body color will be blue and it will have a red band.

Shop equipment (test caps, blind plugs, adapters, etc.) used for pressure testing shall be painted whole body light gray with a color band corresponding to the WP of the shop equipment itself as per Table 2-2: Pressure-Containing Testing Services Surface Equipment Color-Coding and pressure ratings stenciled on the body (or identified with banding tags).

## 2.4.2 Asset Certification

An item of equipment will be considered as qualified and approved for use if:

- It has a Quality File as per Section 2.3.1: Asset Certification and Traceability.
- It holds the third party certifications as required by this manual or by local regulations.
- It holds a current major survey, current annual survey, and has had an operational check since the date of the most recent annual survey.
- It is green tagged and has been suitably maintained and left ready for use, with FIT, TRIM and all required calibrations completed and current, and entered into RITE.

### 2.4.2.1 Qualification of Contractors

Where the Annual or Major survey is performed by a 3rd party contractor, or contractor company, not directly under the supervision of Testing Services personnel, the following evaluations shall be made prior to any work being carried out:

- The experience, competence and certification status of the contractor personnel.
- The quality systems in place which the contractor will work to.
- The workshop and facilities available for the work (if it is not being performed in Schlumberger facilities).
- A similar evaluation of any sub-contractors who will be involved in the process.

Ownership of these evaluations must be taken by the Testing location Management. An Audit/Inspection report should be entered into Quest and any remedial actions closed out. Records of any such evaluation must be retained in the location records for reference. For locations where permanent contracts exist, an audit/inspection should be conducted every year or when changes in key personnel or facilities could affect working practices.

## 2.4.3 Replacement of Parts or Equipment Repair / Re-Manufacturing

When structural parts which are of a pressure retaining or load bearing nature (For example housings, bodies, etc.) are repaired or replaced the asset loses its certification status and shall require witnessed testing by a certifying agency. This re-certification includes post-repair witness of the proof pressure test along with other functional and operational tests part of the initial asset FAT procedure.

This applies to all parts whether supplied from a Schlumberger Technology centre or direct from an approved third party vendor. It is the responsibility of the location to ensure documentation relating to replacement parts is supplied with those parts as this process is not automatic. All documentation relating to the replacement parts, including material traceability documents, should be filed in the equipment Quality file, details of the replacement parts must be included in a RITE Work Order as described in POM section 1.10.3: Traceability.

Equipment remanufacturing is any process where welding, heat treatment, metal recharging and/or machining or other abrasive operations are performed on pressure-containing or pressure-controlling parts to restore the equipment to operational status. Such repair of equipment shall be performed exclusively by Testing Services Technology Centers, or by local or regional workshops approved and supervised by them, following qualified procedures (e.g., ASME section IX for any welds). The process for using a Local or Regional approved workshop is described in Appendix C.

Equipment undergoing such remanufacture loses its certification status and shall be certified again by a certifying agency. The repair workshop shall be specifically requested to provide a renewed certification with the repaired equipment. All documentation related to equipment repair and NDE tests shall be included in the equipment Quality File. This includes certification and traceability of new structural parts.

It is imperative that if any component of a piece of equipment is marked with an individual serial number, or other markings which link the component to individual component certification documentation, that the number or markings remain clearly visible for the life of the component. Loss of the serial number or markings renders the component useless as its' traceability will have been lost. If it is observed during maintenance that the number or markings on a particular component are being eroded, then it is permissible to re-mark them, but this must be done under the supervision of a 3 party witness having first confirmed with the product centre responsible for the manufacture of the tool that the proposed remarking will not damage the component by creating stress areas which may lead to cracking or corrosion.

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**Note**

Hardware or Firmware modification to Safety Equipment and/or Pressure controlling/Pressure Containing equipment such as ESD, PRV's, etc... is forbidden unless approved by the Product Center responsible for that equipment. Approval can be via Modification Recap (for Fleet), via an RFQ or via InTouch (for individual asset).

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## 2.4.3.1 Repair / Re-Manufacturing Documentation

Repair / Re-Manufacturing documentation shall be traceable, and shall be included in the equipment Quality File along with any applicable recertification documentation. The updated Quality File should be organized with a logical structure. The recommended index is as follows:

1. Product Centre, Supplier or Main Contractor's Certificate of Conformance for the most recent recertification (CoC).

2. Any associated third party Recertification Certificates (if Applicable).
3. Revised as built drawings (if Applicable).
4. Any earlier issued CoCs regarding overhaul/inspection/ survey.
5. Any earlier issued associated third party Recertification Certificates.
6. OEM's CoC (from when it was originally fabricated).
7. Design specification.
8. Third party documentation (i.e. design verification report, type approval etc.)
9. The remaining original Quality Plan.
10. Inspection and Test Plan (as applied to the Repaired / Remanufactured item)
11. Inspection reports.
12. NDT reports.
13. Repair documentation (including any applicable Welding Procedure Specifications etc.)
14. Traceable material certificates, as a minimum for the pressure exposed and load bearing components.
15. Any deviations from the standard plan procedures and subsequent compensating measures.
16. Test reports/ print outs.
17. Calibration certificates (pressure test equipment etc.)
18. Welders' certificates, NDT inspectors' certificates, Coating inspectors certificates etc.

## 2.4.4 Reception Control

Before entering into service, all new equipment received by a location shall be subject to a Reception Control according to the RITE TRIM check procedure. This would include a visual inspection to check for mis-assembly or transit damage, hydrostatic body test to WP, and a function check. For equipment received from a Schlumberger Product Center, the identification markings on the equipment shall be checked in order to verify invoicing details and conformity to the requirements of Section 2.4.1: Equipment Identification and Marking. Third party supplied equipment shall be marked at this time, if not already marked by the supplier, to conform to the same requirements.

For equipment which is manufactured or supplied by a Schlumberger Product centre the initial creation of the equipment in RITE is the responsibility of the Schlumberger Product Centre supplying the equipment. The Product Centre Customer Service will then transfer the asset within RITE to the receiving location.

It is the responsibility of the receiving location to ensure that a reception is made in RITE so that the equipment record can be updated with the details of the reception control, and any subsequent maintenance or job events. For equipment supplied by a third party, it is the location responsibility to generate and update the equipment record in RITE.

The Quality file shall also be checked at the time of equipment reception, and any non-conformity reported to the supplier. The date of the initial certification pressure test shall be verified and entered in RITE (if not already entered by the Product Center) to provide the basis for the due dates of futures Q-Checks and Certifications.
The commissioned date entered in RITE should be the same as the FAT dates indicated on the Quality Files.

At the time of reception, any new equipment which has been in-transit for an extended period may be due, or nearly due, for a Q-Check without ever having been used. In such cases a normal reception control should be performed, and an exemption submitted against having to do any thickness checks which would normally be required for the Q-Check. If the exemption is approved, the reception control may then be recorded in RITE as a Q-Check. If this is done the QUEST exemption number must be clearly stated in the RITE Work Order.

## *2.4.5* History Card

Each item shall have a record in RITE. Additionally, each item may have an individual History Card in hard copy which may be printed from RITE.

Initial and subsequent maintenance checks performed shall be adequately recorded in RITE.

Maintenance, repairs, inspections and utilization records (by way of Service Reports) shall be routinely entered into RITE when, or immediately after, they are performed. Any parts replaced shall be noted in such a way that traceability is maintained. The date of the relevant RITE Work Order will be used to indicate the validity of Q-Checks and Certification (Annual and Major Surveys).

## 2.4.6 Equipment Transfer

The relevant documents in the equipment Quality File shall be transferred with the equipment and the retained records amended accordingly.

If an entire assembly is transferred to another location, the pertinent equipment Quality File shall accompany the set transferred. The sending location shall retain a safety copy of all certifications, survey records and traceability records until notified of safe receipt, for a maximum of one year.

## 2.4.7 Equipment Loan

When equipment is loaned to another location, the loan shall be recorded in RITE by means of a loan out movement. Original certification and traceability records are retained by the sending locations, and copies, if not attached to the RITE records of the equipment being loaned, must be sent to the receiving location as required.

The receiving location is responsible for making a reception of the movement and for maintaining the equipment qualification, as per present guidelines. Any hydrostatic test records, maintenance records, and job history details shall be recorded in RITE by the receiving location, and shall be printed and included in the Quality File by the lending location.

## 2.4.8 Equipment Disposal

When a complete assembly is retired, its equipment Quality File shall be removed from active records and retained for a minimum of one year. Local procedures might dictate longer retention periods.

The item or equipment set being retired shall not be sold or loaned. All components shall be rendered unusable. Schlumberger identifications and signs shall be removed.

The equipment shall be disposed of responsibly, following the requirements outlined in the local waste management plan, and using only Schlumberger approved disposal vendors.

### 2.4.9 Equipment Sales

Pressure-containing equipment already used for Schlumberger operations must not be sold. In special cases, when line management approves a sale, second-hand Schlumberger equipment shall have, as a minimum, a third party test and inspection report. Equipment specifically manufactured for Product Sales will follow Schlumberger Technology Center regulations.

## 2.5 Asset Maintenance - RITE

All pressure containing and controlling equipment is subject to regular Maintenance RITE (FIT - TRIM) and re-qualifications for use through Annual Surveys (Q-Check).and Major Surveys. (Certifications).

Maintenance Procedures and pressure tests are defined for each type of equipment in the Maintenance and Operations Manuals which are available through InTouchSupport.com.

The Testing Services Maintenance Standard (InTouch Content 4742288) provides details of roles and responsibility and the basic maintenance process at the base level.

### 2.5.1 RITE Maintenance and Tracking Definitions

#### 2.5.1.1 FIT (Fast Inspection of Tools)

Checks performed on equipment just prior to performing a job.

Minimum FIT requirements:

- Visual inspection to check general physical condition (damage, rust etc.).
- Function checks.
- Pressure test.

#### 2.5.1.2 TRIM (Tool Review and Inspection Monthly)

Typically a complete rebuild and FIT of the equipment performed after each job.

**Note**
When performing a TRIM on vessels, if the PSV's have not been removed for calibration it is accepted to pressure test at 90% of the PSV setting

### 2.5.1.3 Q-Checks (Annual Survey)

Equipment containing or controlling pressure is qualified and certified for use through Q-Checks (Annual Surveys).

The minimum frequency for these inspections and hydrostatic body tests is once per year unless specifically defined otherwise.

The Q-Check shall be conducted as set out in the equipment maintenance manuals, or in the case of piping and surface crossovers, as detailed in of the Pressure Operations Manual.

Operating tests, hydrostatic body, and seat tests for valves, shall be conducted at rated Working Pressure (WP) for all equipment except surface piping and WHE.

Hydrostatic tests on surface piping shall be conducted at Test Pressure (TP). The requirements for WHE are detailed in the Wireline Pressure Operations Manual (InTouch content ID 3046294).

Equipment going on a job must have a current Annual Survey with an expiry date which is at least as far in the future as the the estimated job duration plus one month at the time of load out.

**Note**
Having a certifying authority witness the annual survey is not required by this standard but may be required to meet local regulations or customer requirements.

**Note**
PSV's must be removed from vessels and replaced with blank flanges at the time of an Annual Survey so that the pressure test can be performed at full WP.

### 2.5.1.4 Certification (Major Survey)

In addition to Annual Surveys, pressure-containing and pressure-controlling equipment used by Schlumberger Testing Services shall undergo Major Re-Certifications at regular intervals.

The minimum frequency for Major Re-Certification shall be five years. This is in accordance with the Det Norske Veritas recommended practice for the Recertification of Well Control Equipment. (DNV-RP-E101).

More frequent requirements may be specified in the relevant equipment manual or determined locally, based on customers and local regulations.

A Major Re-Certification typically entails a Survey conducted by a certification agency (Bureau Veritas, DNV, Lloyds, ABS, etc.) and results in issuing new certification documents against industry standards.

Before any Major Re-Certification work commences, an Inspection and Test plan which describes the work to be performed during the recertification process shall be in place, with clearly defined acceptance criteria for each inspection or test which is to be performed. This information should normally be available in the equipment manuals and/or POM, or from established working practices.

Major survey requirements would typically include the following (but for detailed Major Survey requirements, refer to the relevant discipline section of this POM).

- A review of the original Quality File and records of replacement parts or repairs with special focus on traceability.
- A review of the design specifications.
- A review of the job exposure and maintenance records to verify the amount of operational history and the extent of maintenance performed.
- A visual inspection to check general physical condition (damage, rust etc.)
- A strip down and cleaning of mechanical parts in line with the equipment Maintenance Manual.
- A dimensional and thickness test using Non Destructive Examination (NDE): direct measurements, ultrasonic, or X-rays.
- A crack test of any load bearing threads or pad eyes using dye penetrant or MPI. Additionally any other thread or weld which shows visible damage should also be checked with one of these methods.
- A hydrostatic body test to Test Pressure.
- A seat test and operating test at Working Pressure.

Additionally, when lifting eyes and frames are an integral part of the structure:

- A lifting proof-load test.
- A crack test of lifting eyes and structures after the load test.

Please refer to Appendix A: Pressure Test Bays for detailed pressure testing procedures.

### 2.5.2 RITE Service Report (Utilization Records)

Any usage of the equipment shall be recorded in a RITE Service Report. In order to preserve consistency of data and minimize the number of separate manual inputs, the Service Report should be sent to RITE direct from FTL.

The information in the Service Report must include details of use in corrosive environments ($H_2S$, $CO_2$, acid), sand production, over-pressuring, high temperature, tensile loads and any other condition which may affect the future performance of the equipment.

### 2.5.3 Work Order History Requirements

When entering Work Orders in RITE it is important to update them with as much information as possible about the work being performed on the tool. This includes details of any damage or wear which is found, corrective actions taken, and the part numbers of any pieces which have been replaced.

Parts may be selected from a bill of materials which appears following a search for “parts of selected equipment”. This is described in In Touch content (TBA) on filling out a Work Order.

The bill of materials in RITE has flags to identify any parts which are designated as being critical (See POM section 3.7.6: Critical parts of Manufactured Well Barrier Elements) - they are clearly highlighted in Red, and have the word “True” in the right hand column.

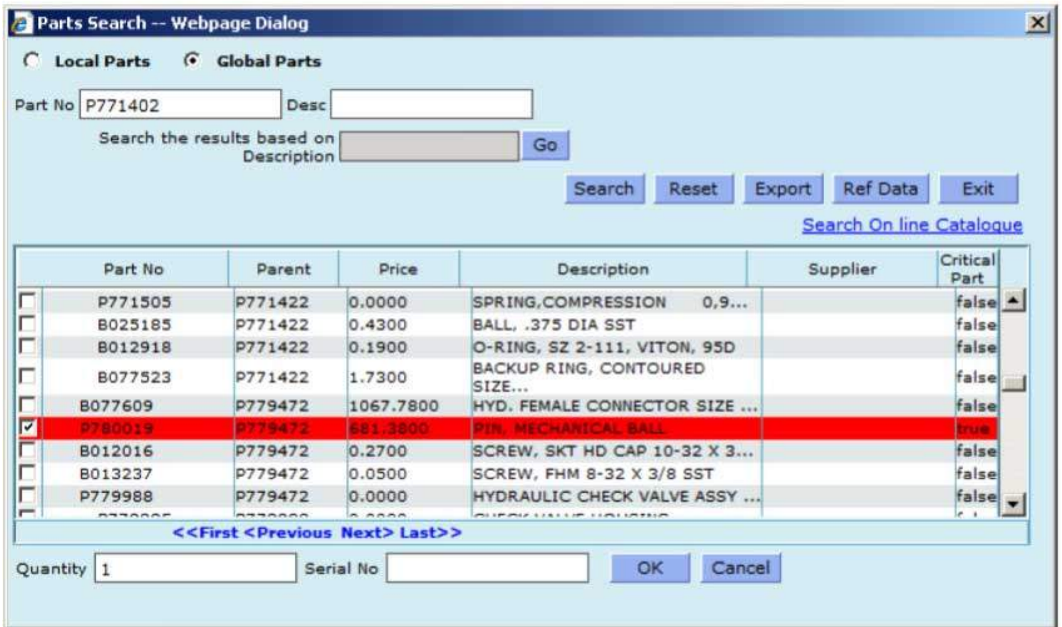


**Figure 2-2: Part Search - Webpage Dialog**

When one of these critical parts is replaced, it is mandatory to enter the serial number or marking details of both the part which was removed, along with its fate (i.e. scrapped or used for another tool), and the serial number or marking details of the part newly installed, along with its source (i.e. New or from another tool, and if from another tool which one) in the “Action Plan and Work Order History” section of the Work Order.

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**Note**

When a critical part is selected from the parts search as shown in Figure 2-2: Part Search - Webpage Dialog, the Work Order cannot be saved until the serial number of the replacement or new part has been entered.

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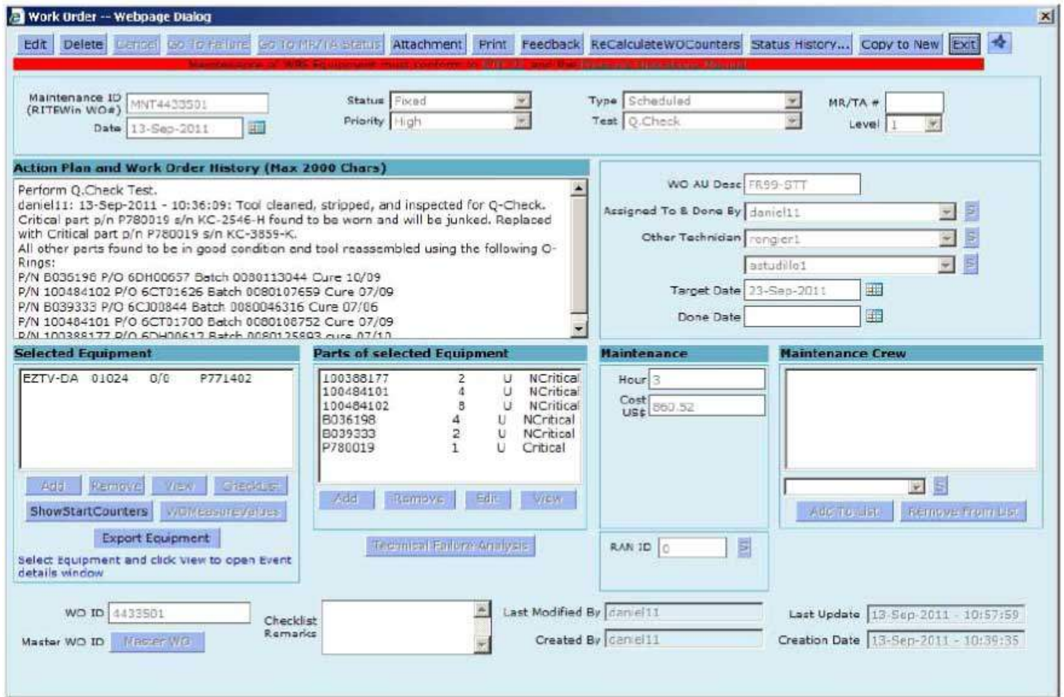


**Figure 2-3: Work Order - Webpage Dialog**

The name of the person who is performing the work must be selected in the "Assigned to or done by" section of the Work Order. If the file size permits, a copy of the certification documentation of the new part should be attached to the Work Order, but in any case it must be added to the equipment quality file along with the reference number of the RITE Work Order, as described in POM section 1.10.3: Traceability.

When replacing O-Rings or other seals in equipment identified as Well Barrier equipment, it is also mandatory to enter the details from the packaging of the elastomers used (batch number cure date, etc).

This is also recommended good practice for all other equipment Work Orders. By entering these details in this way they will subsequently appear on the RITE Equipment History card when it is printed and the tool history will be easily readable.

## 2.5.4 Equipment Status Identification

During maintenance or repairs, the equipment shall be tagged with colored tags or labels in accordance with the RITE program to enable a quick identification of its operational status. Equipment without tags shall be considered unfit for field use.

## 2.5.5 Pressure Test Requirements

A complete hydrostatic test is a body integrity test to test pressure, followed by a seat and operational test to Working Pressure.

A complete gas test is a body integrity test to Working Pressure, followed by a seat test to Working Pressure.

Please refer to Appendix A for detailed pressure testing procedures.

Testing of pressure-containing equipment shall include all pieces and parts contained within the assembly, including all spare accessories that have been numbered and identified for field use.

Pressure gauges and recorders shall be accurate to 0.5% full scale. They shall be recalibrated regularly against a precise standard (dead weight tester or master gauge), according to manufacturers' specifications. Calibration shall not be older than three months for pressure measuring devices used for annual qualification tests.

Pressure tests shall be recorded by using a hard copy device, either a circular plot from a pressure recorder or a hard copy log from a computer device. One axis shall be scaled in pressure units and the other shall be scaled in time. If a chart recorder is used, it shall be fitted with a clock rotation speed appropriate for the duration of the test. Two- to four-hour clocks are recommended for the standard 5 to 15 min hydrostatic tests. (See Figure 2-4: Pressure Test Chart - Annual Survey of 10 kpsi WHE Set).

The hard copy plot shall be marked with the following information:
- Equipment identification - all items of equipment shall be listed.
- Type of test (integrity, operational).
- Test fluid (optional).
- Test pressure.
- Result of tests and remarks.
- Date of test.
- Name and signature of tester or of supervisor.
- Name and signature of third party witness, when required.

The date of last pressure test and test pressure values should be marked on each item of equipment tested, with metal bands, metal plates, stencils or other suitable marking methods, durable but replaceable.

The hard copy plot shall be retained in the equipment history file. It should also be scanned and uploaded to the RITE work order.

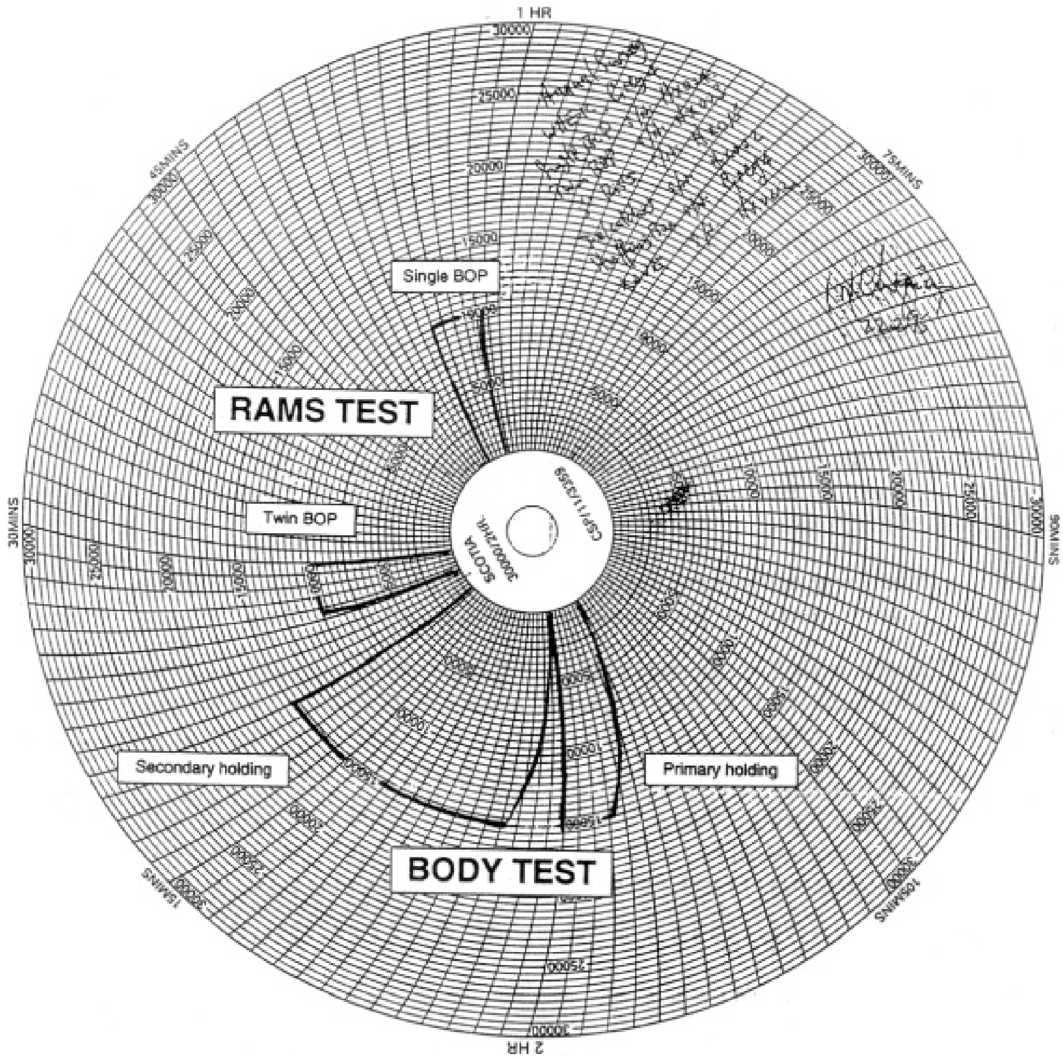


**Figure 2-4: Pressure Test Chart - Annual Survey of 10 kpsi WHE Set**

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### Note

In order to minimize the risk of internal corrosion, pressure test fluids must be properly drained from the equipment on completion of the test and the equipment stored, with any valves in the open position, in a dry, well ventilated area, and ideally under a high roof.

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A stamp similar to the example in Figure 2-5: Pressure Test Chart Stamp can be made and used to ensure all relevent information is captured on the test chart.

**Testing - Pressure Test Bay**

Date: ______________ Time: __________

Tool Type & S/N : ______________

Test Type : ______________

Pressure Apply : ______________

Recorder S/N. ______________

Gauge S/N. ______________

Tester : ______________

Witness : ______________

RITE WO # ______________

**Figure 2-5: Pressure Test Chart Stamp**

## 2.5.6 Examination Procedures

### 2.5.6.1 Non Destructive Examination (NDE Tests)

Used in conjunction with hydrostatic body tests to verify that the equipment retains its structural soundness and can be safely operated within the specified Working Pressure limits. NDE tests are either of the surface NDE type: magnetic particles (Magnaflux) or dye penetrant or of the volumetric NDE type: X-ray radiography, gamma-ray radiography, eddy currents, acoustic emission or ultrasonic examination. Surface NDE tests are valid only to detect surface cracks or damage. To check for internal erosion, corrosion or other internal defects and thickness losses, volumetric NDE methods shall be used. The most practical of the volumetric tests, recommended by Schlumberger for thickness determination is the ultrasonic method.

### 2.5.6.2 Radiography

Radiographic examinations shall be conducted to examine welds for internal soundness (integrity). It shall be performed in accordance with procedures specified in ASTM E94. Both X-ray and gamma ray radiation sources are acceptable within the inherent thickness range limitation of each.

### 2.5.6.3 Ultrasonic

Ultrasonic examination shall be conducted to verify wall thickness when other measuring methods are not possible (e.g., separator and surge tank vessel, piping, etc.) and shall be performed in accordance with the design codes of the given tool.

### 2.5.6.4 Magnetic Particle or Liquid Penetrant Inspection

Magnetic particle (MPI) or Liquid Penetrant Inspection (LPI) methods shall be used to detect surface cracks or damage. It shall also be performed to reveal cracks and flaws after heat treatment and final machining operations and shall be performed in accordance with the design codes of the given tool.

MPI shall be in accordance with procedures specified in ASTM E-709.

LPI shall be in accordance with procedures specified in ASTM E-165.

### 2.5.6.5 Hardness Test

Hardness Test is performed only after a repair involving welding/heat treatment/ stress release.

At least one hardness test shall be performed in both the weld and the adjacent unaffected base metal after all heat treatment and machining operations to ensure compliance to NACE MR-0175 ($H_2S$ service). Hardness testing shall be performed in accordance with one of the following:

- ASTM E10, Standard Test Methods for Brinell Hardness of Metallic Materials.
- ASTM E18, Standard Test Methods for Rockwell Hardness and Rockwell Superficial Hardness of Metallic Materials.

## 2.5.7 Shelf Life of Elastomer O-Ring Seals

Elastomer compounds deteriorate over time in the presence of ultraviolet light (sunlight), ozone, radiation, heat and moisture. In order to maintain their optimum condition the seals must therefore be dry stored in airtight opaque bags at less than 120 degF [48.88 degC], and away from direct sunlight.

The discard (ie disposal) date for a packet of unused O-rings should be printed on the packet label by the manufacturer. This date refers to a packet which remains sealed, and once the packet is opened the O-Rings must be used as soon as possible. The discard date printed on the packet will generally follow the schedule given in the table below and in any case must always be observed. Limits for the maximum shelf life of O-Rings which are stored in open packets is also given in Table 2-3: Shelf Life of Elastomer O-Ring Seals.

**Table 2-3: Shelf Life of Elastomer O-Ring Seals**

| Elastomer family | ASTM Abbreviation | Shelf life |
|---|---|---|
| Nitrile | NBR | 15 years in original sealed packaging, otherwise 5 years. |
| Neoprene | CR | |
| Hydrogenated Nitrile (HSN) | HNBR | 15 years in original sealed packaging, otherwise 10 years. |
| EPDM | EPDM | 20 years irrespective of packaging |
| Aflas | FEPM | |
| Fluorocarbon elastomer (Viton, Fluorel, Technoflon) | FKM | |
| Perfluoroelastomer (Chemraz, Kalrez, Simriz, Technoflon) | FFKM | |
| Silicone, Fluorosilcone | | |

Protective packaging is an effective technique to minimize deterioration of these materials while stored, and once the package is opened to remove a quantity of seals, the package should be kept folded (and preferably taped) closed unless there is there is an immediate to remove further seals.

Elastomers should always be kept in such a manner as to provide maximum protection from adverse conditions.

# 2.6 File Codes – RITE

For equipment manufactured in a Product Centre, the File Codes (also referred to as Asset Codes or Equipment Codes) are created in GeMS by the manufacturing engineers. RITE then imports the File Codes from OneCat and a RITE administrator assigns the required maintenance events and measure points before releasing the code for use. Product Centre manufactured equipment is created in RITE at the time of completion and is then transferred to the purchasing location at the time of physical shipment.

For third party items, which will not be created in GeMS, the File Codes are created directly in RITE by an administrator.

All pressure containing or controlling equipment must be entered in RITE in order to monitor its Technical status. This must be verified at the time of reception control. (See Section 2.4.4: Reception Control).

It is recommended that any other equipment which requires control of certification status or movement tracking is also entered into RITE.

It is the responsibility of the location to ensure that all equipment entered in RITE has been created using the correct File Code.

## 2.6.1 Downhole or Below Flowhead Crossover Codes

All subs and crossovers which are run anywhere in the string and which are not included as an integral part of a larger piece of equipment such as a Lubricator valve, SenTree, or DST tool must have a Quality file, and must be entered in RITE under their correct equipment code. For subs and crossovers, the equipment codes are based on the part number of the item as this allows the full technical specification - thread type, tensile load capacity, OD, ID, WP, etc - to be identified.

This gives benefits of easier searching when a crossover with particular specifications is required, better recognition for allocation in i-District, and easier matching to Q-Files than the generic codes which were used previously. All the Sub and crossover codes begin with the 3 letter code XDH (X-overs Down Hole) followed by a hyphen (dash) and the part number of the sub or crossover. (Examples: XDH-100240227, XDH-100844398, etc).

Test Caps and Plugs are also included in the scheme. In a future development of RITE, the technical specifications of each sub or crossover will automatically appear in the "Type of Equipment Details" window accessible from each equipment card.

At the present time, this information is uploaded in batches by the RITE software team, or alternatively can be entered manually.

The technical specifications can also be checked in OneCAT. Further details of the scope of the technical specifications and on how to look up the details of any particular sub or crossover are given in InTouch Content ID 5413498.

## 2.7 Section 2 Revision History

For more details see Appendix F.

**Warning**
Potential Severity: Serious
Potential Loss: Security
Hazard Category: Human

The controlled source document of this manual is stored in the InTouch Content ID 3045666. Any paper version of this standard is uncontrolled and should be compared with the source document at time of use to ensure it is up to date.

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# Well Integrity

# 3 Well Integrity

In all well operations a number of different means of control are used to prevent the uncontrolled flow of fluids or gasses from the producing formations into other formations or to the surface or environment. Generally several different means of control will be required to work together as an integrated package to contain the well effluent inside an envelope. For example, the Casing (or liner) + Packer with annulus fluid above + DST string with a valve, all work together to contain the reservoir fluids within the reservoir and test string envelope. This envelope is referred to as a “Well Barrier” and each of the means of control which are working together to make it effective are referred to as “Well Barrier Elements”. A number of Well Barriers (envelopes) may be in place on a well at any given time, and the minimum number required for safe operations is two.

Schlumberger Testing Services personnel working at wellsites must have an adequate understanding of what a well barrier is, and how it may be constructed using different well barrier elements, as well as the competence to establish, test, monitor, restore, control, maintain, and repair the elements of them which are under their responsibility.

This understanding and competence is key in ensuring that the Integrity of the well remains intact, and that an out of control situation will not develop.

Well Integrity is a matter of principal concern to all Schlumberger employees, contractors and consultants that may become involved in activities along the lifetime of a well, including non-naturally flowing well, from the planning stage, through its construction, completion, intervention, and operation until its final PB & abandonment.

It concerns not only Testing Services field personnel, but also all those who are involved with the design and manufacture of flowheads, downhole and subsea tools, tubular crossovers, and any other string components or equipment, and all those who service, maintain, or repair them, as well as marketing and sales functions.

## 3.1 Definitions

| Term | Definition |
|---|---|
| **Well Integrity:** | A quality or condition of a well relating to the structural soundness of the well by application of technical, operational and organizational solutions, such as the use of competent pressure seals, to reduce the risk of an uncontrolled release of formation fluids into another |

formation, to the surface, or to the environment, throughout the well life cycle to a level which can be demonstrated to be “ALARP” (As Low As Reasonably Practical).

Well Integrity is established by implementing and maintaining well barriers to prevent uncontrolled release of fluids from the formation while performing well operations (such as well testing) or while the well is inactive or abandoned.

**Well Control:** A collective expression for all activities that can be applied to contain formation pressure and prevent the uncontrolled flow of fluids or gasses from the formation into another formation, or to the surface or environment.

**Barrier Element:** Any device, object or element such as a fluid column, casing, tubing, tubular crossovers, BOPs, WHE, Flowhead, Lubricator valve, SenTREE, or DST tools, that either alone or in combination with other elements is capable of containing well pressure and preventing the uncontrolled flow of fluids or gases from the formation into another formation, or to the surface or environment.

**Note**
Fluid may only be considered as a barrier element, or part of a barrier element, if it can be monitored and maintained. This requires that a reserve of fluid must also be available for immediate use in order to replace any losses.

**Note**
After verification of condition, such as by a cement bond log and a pressure test, the cement between the casing or liner and the formation should be considered as an integral part of the casing or liner barrier element.

Although this verification is the Client’s responsibility, and is outside the roles of Testing Services personnel, when designing or performing a job which involves Testing Services downhole tools or equipment it is the responsibility of the Testing Services supervisor to confirm with the client that this verification has been satisfactorily carried out.

After satisfactory verification, each casing or liner size and its associated cement should be considered as separate barrier elements. However, when perforated for production or testing, the perforated casing or liner and associated cement is no longer considered as a barrier element below the point of the top perforation unless two packers are utilized in order to isolate the perforated section. (One positioned above the top perforation and one below the bottom perforation). If any perforated section(s) is / are isolated by setting one packer above the perforated interval and another packer below it, then it is allowable to consider any section of un-perforated casing and cement below the lower packer as a barrier as long as it can be pressure or inflow tested.

| | |
|---|---|
| **Well Barrier Envelope:** | The combination of Barrier Elements (as described above) which, when properly deployed and working together, form a containment envelope that prevents the uncontrolled flow of fluids or gases from the formation into another formation, or to the surface or environment. |
| **Primary Well Barrier:** | An Element or combination of Barrier Elements that is in direct (Primary) contact with the potential outflow source, i.e. the elements that are normally exposed to formation fluid or gas pressure during well operations.<br><br>Examples of Primary Well Barriers in place during well testing are shown in Blue in the following illustrations.<br><br>**Note**<br>Having more valves (Master Valve, Lub Valve, SenTREE, etc...) upstream or downstream of the Primary Barrier Valves (the Flowhead valves shown in blue) will only add redundancy to the system rather than creating a new Barrier as the whole of the Primary Barrier must be intact to maintain integrity during flow operations. |
| **Secondary Well Barrier:** | An Element or combination of Barrier Elements which have been designated as the ULTIMATE defense should any of the Primary Barrier Elements fail, and as such prevents an uncontrolled flow from the well to surface or to the environment. It is the LAST and ULTIMATE barrier envelope which provides well Integrity to be activated. It is not necessarily barrier number two in a sequence which may include a number of intermediate Well Barriers between those which are designated as the Primary and Secondary Barriers.<br><br>Examples of Secondary Well Barriers are shown in Red in the following illustrations. |

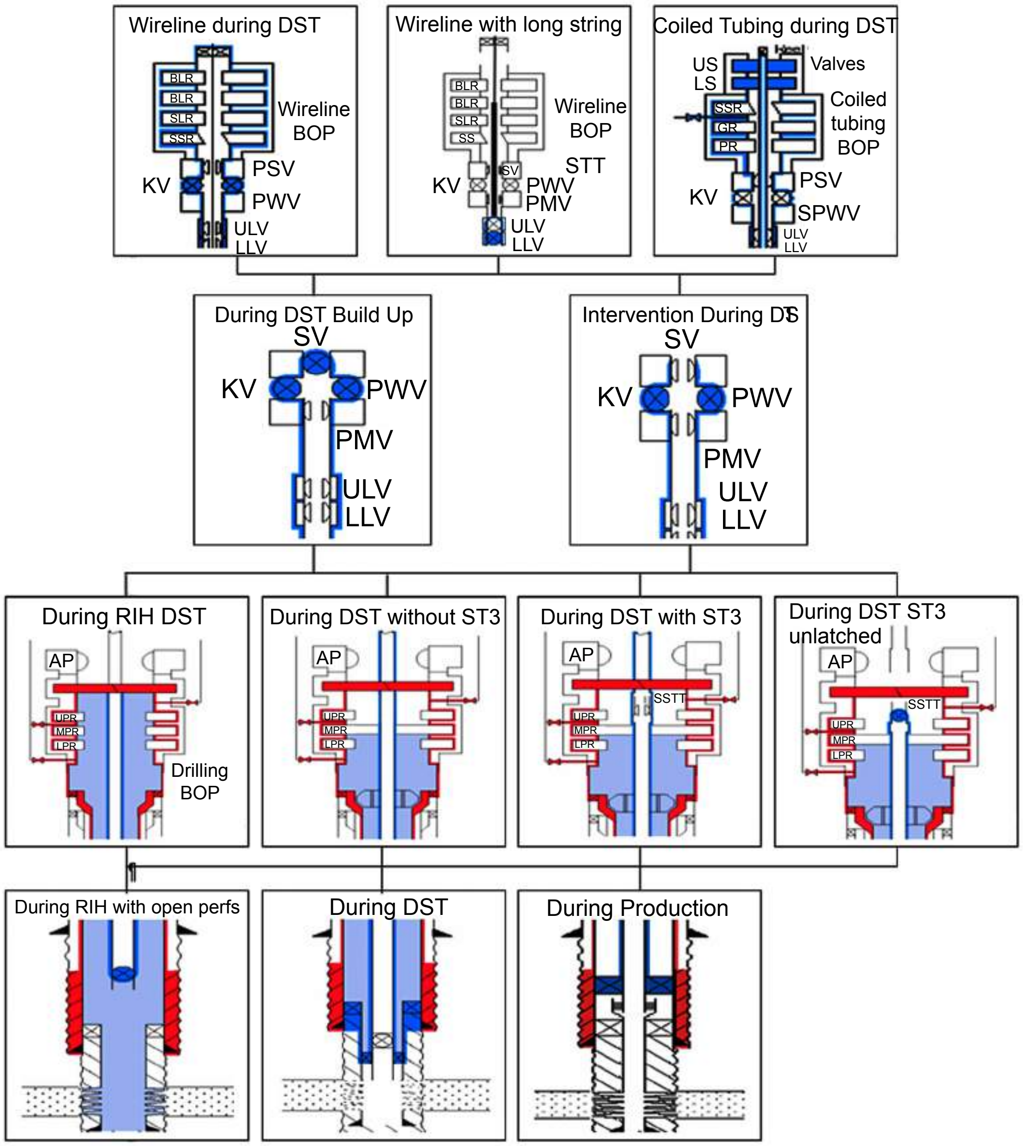


**Figure 3-1: Primary and Secondary Well Barriers**

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## Note

During the normal process of performing operations the combination of Well Barrier Elements used to construct the well barrier envelopes, especially the Primary Well Barrier Envelope, will change. For example, when running the string into the hole for the first time, the casing or liner will usually be intact across the reservoir and can be considered as being a primary barrier. When pulling out however, the casing or liner will usually be in a perforated state, and the Primary Well Barrier Element will be the kill weight fluid in the wellbore.

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| Typical Primary Well Barrier Elements |
|---|
| 1. Stuffing Box or Grease Seal |
| 2. WHE Riser or Lubricators Sections |
| 3. WL/SL/CT BOP |
| 4. CIRP Gate Valves |
| 5. Flowhead / Production Tree |
| 6. Lubricator Valve |
| 7. SenTREE or EZ-Valve |
| 8. Tubing and Crossovers |
| 9. DST tools |
| 10. Packer and annulus fluid column |
| 11. Smallest size of Casing or Liner run and pressure or inflow tested |
| 12. Liner top packer |

| Typical Secondary Well Barrier Elements |
|---|
| 1. Drilling BOP |
| 2. Wellhead |
| 3. Conductor casings or surface casings with good and proven cement bond and successful pressure or inflow test which are not already designated as being a Primary Barrier Element. |

**Figure 3-2: Typical Primary Well Barrier Elements**

| Term | Definition |
|---|---|
| **Common Barrier Element:** | A Barrier Element that is simultaneously part of both the Primary and the Secondary Well Barrier Envelopes is referred to as a Common Barrier Element. If the common element fails, BOTH barriers will fail so Primary & Secondary Barriers are not independent. A Risk Analysis and Mitigation (HARC) shall be conducted prior to starting any well intervention where a common barrier element is used in order to assess the risk of its failure and the potential consequences. An exemption should also be raised against the normal requirement to have two independent barriers and be approved before work commences, in line with the Management of Change and Exemption Standard (SLB-QHSE-S010). |

*eg* **Example**

The Master Valve installed in the base of a Christmas tree on a production well which does not have any downhole valves is a Common Well Barrier Element. It is in direct contact with the pressured fluid in the well (PRIMARY BARRIER in blue) and simultaneously, it forms part of the surface equipment that ultimately may contain flow and pressure (The SECONDARY BARRIER in red). However, most production wells are equipped with Safety valves which isolate the primary barrier from the secondary barrier.

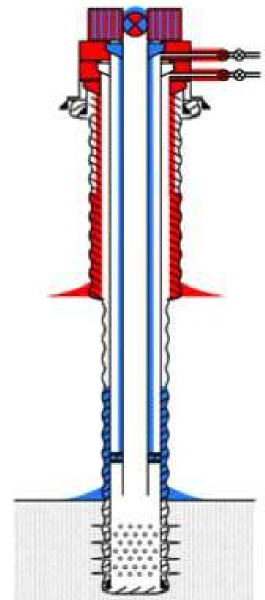

**Figure 3-3: Common Barrier Element**

| | |
|---|---|
| **Manufactured Well Barrier Equipment:** | Any manufactured tool or string component which will be subsequently used as a Well Barrier Element. Specifically for Testing Services, this includes, but is not limited to:<br>• All DST Tools.<br>• SenTREE and EZ Valve tools, and associated items which are run in the hole (Slick Joints, Shear Subs, Retainer and Lubricator Valves, etc).<br>• All Crossovers run in the string.<br>• SCAR.<br>• DGA (or other gauge Carriers), DLWA, and LDCA.<br>• Surface Testing Flowheads.<br>• Gate Valves. |
| **Well Barrier Element Acceptance Criteria (WBEAC):** | In order to qualify an element as being suitable for use, either alone or in combination with other elements, as being capable of containing well pressure and preventing uncontrolled flow of fluids or gases from the formation, it is necessary to define all organizational, technical, and operational requirements, guidelines and processes that must be fulfilled. These are known as the acceptance criteria, and are specific for each element. |

**Note**

Care must be taken not to confuse the two Well Barriers, or the Well Barrier Elements required for Well Integrity, with the “two Pressure Barriers” required when working with WHE, DST, Subsea, or Process Equipment. (Refer to POM sections: 4.4.1: Surface Pressure Barriers, 5.4.1: Use of a Retainer Valve, 6.3.2: Pressure Barriers for Drill Stem Testing, and 8.5.3: Pressure Testing Downhole).

## 3.2 Job Design, and Planning Well Barriers

Well Barrier Envelopes and their Elements and function shall be clearly defined as an integral part of the job planning process and verified with the client. Each Well Barrier envelope must have clearly defined test and acceptance criteria which must be included in the job programme.

Criteria for shut-down of the activities or operations must also be established and included in the programme. These criteria must include events directly related to a Well Barrier, such as the failure of a Well Barrier Element, and also external influences, such as the necessity to unlatch at the SenTREE when testing a Sub Sea Well.

The Primary and Secondary Well Barriers shall be independent of each other to the maximum extent possible, and where Common Barrier elements exist they must be risk assessed in a HARC and an exemption raised and approved before work commences in line with the Management of Change and Exemption Standard (SLB-QHSE-S010).

Well Barriers shall be designed and/or selected or constructed such that:

- Each Element within the barrier can withstand the maximum anticipated tensile loading at the maximum anticipated internal or external pressure, differential pressure, absolute pressure, temperature, and the well effluent properties to which it may become exposed.
- The weakest elements in a test string with regards to burst, collapse, and tensile strength rating shall be identified by referencing tool manuals or OneCAT Engineering data, and clearly marked on the string diagram with their limiting factors listed. It must be recognized that the position of each element in the string may affect the limiting factors – tensile requirements are greater nearer the surface for example.
- Each Element which is a valve or tool can be operated effectively using standard operating procedures as detailed in the operating manuals, and withstand the environment to which it may be exposed for the duration of the anticipated operations plus a safety margin, with the size of the safety

margin being determined by POM requirements for equipment selection and job design (especially sections 4.3: Surface Testing Equipment General Rules and associated subsections, 5.4: Subsea Safety Equipment General Rules and associated sub sections, 6.3: Downhole Equipment General Rules and associated sub sections, and the Wireline Pressure Operations manual (InTouch Content ID 3046294) section 4.2: Wellhead Pressure Control Equipment) and a job specific HARC.

- Each element, and the Well Barrier as a whole, can be leak tested, and where applicable function tested, or verified by other methods.
- No single failure of a Well Barrier or Well Barrier Element will lead to an uncontrolled flow of fluids or gasses from the formation to another formation or to the environment.
- Re-establishment of a lost barrier or establishment of another alternative barrier can be accomplished.
- Physical position and status can be monitored.

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**Note**

Consideration as to the condition and status of the Well Barriers must be taken into account if changes to the programme are made at any point between the initial job design and final completion of the work, and they must also be included on any job specific HARC.

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The acceptance criteria for Testing Services supplied individual Well Barrier Elements are linked to this appendix in section 3.9: Acceptance Criteria Data Sheets (WBEAC).

A number of these criteria must be satisfied at the time of job planning or pre-job preparation.

See also the following POM Sections regarding Job Design specifications:

- 4.2: Standards and Specifications (Surface Equipment).
- 5.4.1: Use of a Retainer Valve (Sub Sea Equipment).
- 6.2: Standards and Specifications (Downhole Equipment).
- 6.3: Downhole Equipment General Rules (Downhole Equipment).
- and the Wireline Pressure Operations Manual section 4.2 Wellhead pressure Control Equipment (Wellhead Equipment).

At the time of writing the job programme, the stages at which the individual barrier elements, and ultimately the assembled well barrier envelope, are tested and documented must be defined, and procedures and acceptance criteria given. (For example: *"Increase pressure in incremental steps of 500 psi until the test pressure is attained, then hold for 10 minutes while observing for physical signs of leakage or pressure fall off."*) Pressure tests at the wellsite should be conducted in accordance with:

- POM Section 4.5: Wellsite Equipment Pressure Testing and sub sections,
- POM Section 5.7: Wellsite Pressure Testing and subsections,
- POM section 6.5: Pressure Testing and subsections,

  and
- The Wireline POM Section 5.2: Wellsite Pressure Test and sub sections.

As applicable by equipment type.

The job programme should also contain the contingency steps to be followed in the event that any well barrier element or envelope fails to meet the acceptance criteria.

## 3.2.1 Additional Design and Planning considerations for Wireline or Slickline Operations

In the case of Wireline or Slickline operations, consideration to the following Well Barrier Acceptance Criteria must be included at the time of job design. Additional job specific considerations may also apply:

- If "Shear and Seal Rams" are not included in the WL/SL BOP configuration, there must be an alternative method available to cut the cable at surface.
- If shutting in the well during operations is undesirable, then sufficient riser / lubricator sections must be used to accommodate the entire length of the toolstring above the Swab Valve.*
- If it is acceptable to shut the well in during operations, and there is a Lubricator Valve in the string, plus either a second Lubricator Valve installed below first, or an SSSV, SenTREE, EZ-Valve, or DST tester valve is present in the string below the Lubricator Valve, sufficient riser / lubricator sections must be used to accommodate the entire length of the toolstring above the (upper) Lubricator Valve.*

- Without a second Lubricator Valve, or SSSV, SenTREE, EZ-Valve or DST tester valve in the string below the (Upper) Lubricator Valve, sufficient riser / lubricator sections must be used to accommodate the entire length of the toolstring above the Swab Valve.*
- If an SSSV, SenTREE, EZ-Valve, or DST tester valve is present in the string but there is no Lubricator Valve, sufficient riser / lubricator sections must be used to accommodate the entire length of the toolstring above the Swab Valve.*
- The job must be designed, and the programme must be written, with the intention of minimizing the time that any toolstring is obstructing the closure of any valve which is designated as being part of the primary Well Barrier envelope in order to preserve the functional capability of the valve for the maximum period of time.
- The position, mode (Failsafe closed / failsafe as is), and purpose (Well Barrier or Pressure Barrier) of any hydraulically operated valves which the toolstring will pass through must be included in the Well Barrier Schematic and String diagrams. The possibility and consequences of them operating due to a loss or gain of hydraulic pressure must be included in the job specific HARC along with prevention and mitigation measures.
- If perforating guns are to be run, then the job specific HARC and job programme must include steps to ensure that shear rams (either in the drilling BOP or in any other device in the rig up) are not closed on the guns.
- An assessment must be made as to which valves or BOP rams in the Primary Barrier are capable of cutting the Wireline or Slickline which is to be run into the string or tubing should the need for emergency activation of any of the valves arise. The reliability of the valve seal when the valve is closed after cutting must also be considered. A suitable contingency plan for valve or BOP ram closure with Wireline or Slickline in the hole must be developed and included in the job specific HARC and job programme. If pre-job verification tests of the cutting capabilities of any valve is required, these must only be carried out in conjunction with the Product Centre responsible for the manufacture of the valve. The currently established SenTREE ball valve cutting capabilities are available at InTouch Content ID 5705582 (SenTREE 3) and InTouch Content ID 4129312 (SenTREE 7).

* This will maintain the requirement for a testable element in the primary well barrier (The Lubricator valve or Swab valve depending on string configuration) while also giving options for the second “Pressure Barrier” required if the lubricator sections are removed to install, remove, or change a WL/SL toolstring. The SSSV, SenTREE, or EZ-Valve are safety valves and should not be used routinely, however, if installed in the string and pressure tested before operations begin, they are available for use in an emergency situation and can thus be considered as a “Pressure Barrier”.

**Note**

Care must be taken not to confuse the two Well Barriers, or the Well Barrier Elements required for Well Integrity, with the “two Pressure Barriers” required when working with WHE or Process Equipment.

## 3.2.2 Additional Design and Planning considerations for Coiled Tubing Operations

In the case of Coiled Tubing operations, consideration to the following Well Barrier Acceptance Criteria must be included at the time of job design. Additional job specific considerations may also apply:

- If shutting in the well during operations is undesirable, then sufficient riser / lubricator sections must be used to accommodate the entire length of the toolstring above the Swab Valve.*
- If it is acceptable to shut the well in during operations, and there is a Lubricator Valve in the string, plus either a second Lubricator Valve installed below first, or an SSSV, SenTREE, EZ-Valve, or DST tester valve is present in the string below the Lubricator Valve, sufficient riser / lubricator sections must be used to accommodate the entire length of the toolstring above the (upper) Lubricator Valve.*
- Without a second Lubricator Valve, or SSSV, SenTREE, EZ-Valve or DST tester valve in the string below the (Upper) Lubricator Valve, sufficient riser / lubricator sections must be used to accommodate the entire length of the toolstring above the Swab Valve.*
- If an SSSV, SenTREE, EZ-Valve, or DST tester valve is present in the string but there is no Lubricator Valve, sufficient riser / lubricator sections must be used to accommodate the entire length of the toolstring above the Swab Valve.*
- The job must be designed, and the programme must be written, with the intention of minimizing the time that any toolstring is obstructing the closure of any valve which is designated as being part of the primary Well Barrier envelope in order to preserve the functional capability of the valve for the maximum period of time.
- The position, mode (Failsafe closed / failsafe as is), and purpose (Well Barrier or Pressure Barrier) of any hydraulically operated valves which the toolstring will pass through must be included in the Well Barrier Schematic and String diagrams. The possibility and consequences of them operating due to a loss or gain of hydraulic pressure must be included in the job specific HARC along with prevention and mitigation measures.

- If perforating guns are to be run, then the job specific HARC and job programme must include steps to ensure that shear rams (either in the drilling BOP or in any other device in the rig up) are not closed on the guns.
- An assessment must be made as to which valves or BOP rams in the Primary Barrier are capable of cutting the Coiled Tubing which is to be run into the string or tubing should the need for emergency activation of any of the valves arise. The reliability of the valve seal when the valve is closed after cutting must also be considered. A suitable contingency plan for valve or BOP ram closure with Coiled Tubing in the hole must be developed and included in the job specific HARC and job programme. If pre-job verification tests of the cutting capabilities of any valve is required, these must only be carried out in conjunction with the Product Centre responsible for the manufacture of the valve. The currently established SenTREE ball valve cutting capabilities are available at InTouch Content ID 5705582 (SenTREE 3) and InTouch Content ID 4129312 (SenTREE 7).

* This will maintain the requirement for a testable element in the primary well barrier (The Lubricator valve or Swab valve depending on string configuration) while also giving options for the second "Pressure Barrier" required if the lubricator sections are removed to install, remove, or change a toolstring.
The SSSV, SenTREE, or EZ-Valve are safety valves and should not be used routinely, however, if installed in the string and pressure tested before operations begin, they are available for use in an emergency situation and can thus be considered as a "Pressure Barrier".

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**Note**
Care must be taken not to confuse the two Well Barriers, or the Well Barrier Elements required for Well Integrity, with the "two Pressure Barriers" required when working with WHE or Process Equipment.

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**Note**
The main reference document for Coiled Tubing operations is the Well Intervention QHSE Standard 02: Coiled Tubing Operations, InTouch Content ID 5884296. If planning a job run on third party coiled tubing reference must be made to SLB WS Standards as a job design guideline, and any deviations from them would require an exemption in QUEST.

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## 3.2.3 Additional Design and Planning considerations for CIRP Operations

In the case of CIRP operations, consideration to the following Well Barrier Acceptance Criteria must be included at the time of job design. Additional job specific considerations may also apply:

- The Deployment Stack, see InTouch Content ID 3319326 section Appendix E is NOT designed to close in and/or seal the wellbore and must be considered as a tubular Well Barrier Element only. The Well Barrier Elements which can close off the well bore in the event of failure or imminent disconnection of the WHE are the Lubricator Valve (if Run), the production tree (Master or Swab Valves) and the Gate Valves which are mounted above the deployment stack.
- The CIRP Toolstring must include a toolstring release mechanism which can be activated in case of well control issues.

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**Note**

Whilst a ball drop disconnect device is typically a part of the CT BHA, it must be understood that the activation of the disconnect involves circulating a full CT reel volume which could take several hours to complete. Dropping the guns from the CIRP-DS or severing the CT is likely to be a faster means of enabling the creation of a Well Barrier in an emergency.

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- The position, mode (Failsafe closed / failsafe as is), and purpose (Well Barrier or Pressure Barrier) of any hydraulically operated valves which the toolstring will pass through must be included in the Well Barrier Schematic and String diagrams. The possibility and consequences of them operating due to a loss or gain of hydraulic pressure must be included in the job specific HARC along with prevention and mitigation measures.
- The job must be designed, and the programme must be written, with the intention of minimizing the time that any toolstring is obstructing the closure of any valve which is designated as being part of the primary Well Barrier envelope in order to preserve the functional capability of the valve for the maximum period of time.
- The job specific HARC and job programme must include steps to ensure that shear rams (either in the drilling BOP or in any other device in the rig up) are not closed on the guns.
- In the event of CIRP operations on a floating facility, a suitable contingency plan for the requirement to unlatch the SenTREE when the CIRP string is in the hole must be developed and included in the job specific HARC and job programme.

**Note**

The main reference document for Coiled Tubing operations is the Well Intervention QHSE Standard 02: Coiled Tubing Operations, InTouch Content ID 5884296. If planning a job run on third party coiled tubing reference must be made to SLB WS Standards as a job design guideline, and any deviations from them would require an exemption in QUEST.

## 3.2.4 Additional Design and Planning considerations for Subsea Operations

For all Subsea operations, correct BOP stack and wellhead data is imperative in determining the relative position of the SenTREE or EZ-Valve assembly with respect to the BOP rams. Discussions must take place with the client in order to determine which sets of rams are to be closed around the slick joint. This is dependent on the position of the choke lines in the BOP stack. The client must provide an up to date drawing of the BOP stack, along with the dimensions required to design the space out, and sign off the completed design as being correct to ensure well integrity.

In the case of SenTREE operations, procedures and plans relating to the shearing of the string, or disconnection of the SenTREE and Marine Riser, must be reviewed and agreed by all parties during the job design phase.

Consideration to the following Well Barrier Acceptance Criteria must also be included at the time of Subsea job design. Additional job specific considerations may also apply:

- It must be possible to close the test string at the BOP level. For SenTREE operations it must also be possible to disconnect the test string at the BOP level in a controlled manner.
- It must be possible to shear the tubing/Landing string and seal the wellbore at the BOP level. For SenTREE operations it must be possible to shear the tubing or shear joint above the latch assembly to seal the wellbore.

**Note**

This “possibility to shear” relates not just to the position of the SenTREE assembly in the BOP stack, but also the characteristics of the shear sub or landing string and the shearing capacity of the BOP stack.

- If intervention by Slickline, Wireline, or Coiled Tubing is to be made through Subsea equipment, a suitable contingency plan for valve closure with the intervention string in the hole must be developed and included in the job specific HARC and job programme in case the need for emergency activation of any of the valves arises. This must include steps to ensure that any toolstring is clear of the valves before they are activated, an assessment of which valves are capable of cutting the Wire / Cable / Coiled Tubing, and the reliability of the valve seal if the valve is closed after cutting. If pre-job verification tests of the cutting capabilities of any valve is required, these must only be carried out in conjunction with the Product Centre responsible for the manufacture of the valve. The currently established SenTREE ball valve cutting capabilities are available at InTouch Content ID 5705582 (SenTREE 3) and InTouch Content ID 4129312 (SenTREE 7).
- If perforating guns are to be run, then the job specific HARC and job programme must include steps to ensure that shear rams (either in the drilling BOP or in any other device in the rig up) are not closed on the guns.
- When testing from a floating facility is planned, the likely flowing tubing temperature profile(s) should be assessed so that the annulus fluid can be selected/ prepared for both the lowest and highest expected temperatures. The possibility of hydrate formation inside the SenTREE must also be assessed and the appropriate measures to monitor, prevent, and remove hydrates must be included in the job design and programme.
- If power cables or control or injection hoses or liners are to be attached to the outside of the string, and run to a depth which is below the BOP stack, provision must be made for them to pass through the stack without affecting the sealing capability of the pipe rams, by including ported joints or BOP cans in the string design. Also, for all operations where a SenTREE is in the string, consideration must be given as to how the cables, hoses or liners will be disconnected or severed in the event of the need for a SenTREE unlatch.
- For operations in deep water, an assessment of the need for a Riser Sealing Mandrel (RSM) or Cased Wear Joint (CWJ) must be made.
- The need to perform BOP stack tests at regular intervals should be taken into consideration with respect to the expected duration of the job.

### *3.2.5* Additional Design and Planning Considerations for DST Operations

In the case of DST operations, consideration to the following Well Barrier Acceptance Criteria must be included at the time of job design. Additional job specific considerations may also apply:

- It must be possible to kill the well, without exceeding the Working Pressure rating of any piece of equipment, by circulating kill fluid through the Flowhead from surface lines connected to the mud or cement pumps, with the returns being taken through the rig choke and mud / gas separator.
- The ability to monitor the volume of the trip tank, indicating the loss or gain of fluid or gas in the annulus.

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**Note**

It is the responsibility of the Drill crew to monitor the volume in the trip tank, but the responsibility of the DST personnel on the rig floor to be aware of the volumes measured and record them in the DST sequence of events.

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- It must be possible to circulate the test string at any time when the well is live. (i.e. reservoir open to the well bore).
- The capacity of the mud and cement pumps, both in terms of Working Pressure and volumetric pump rate, must be sufficient to carry out any anticipated bullheading or reverse circulating operations.

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**Note**

The pumps to be used must be fitted with functional stroke counters or other form of accurate flow / volume measuring device so that displacement can be adequately monitored during operations. Ideally, the mud and cement pumps should have independent means of power supply so that in the event of one supply failing, the second is still functional.

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- If perforating guns are to be run, then the job specific HARC and job programme must include steps to ensure that shear rams (either in the drilling BOP or in any other device in the rig up) are not closed on the guns.
- If power cables or control or injection hoses or liners are to be attached to the outside of the string, and run to a depth which is below the BOP stack, provision must be made for them to pass through the stack without affecting the sealing capability of the pipe rams, by including ported joints or BOP cans in the string design. Also, for all operations where a SenTREE is in the string, consideration must be given as to how the cables, hoses or liners will be disconnected or severed in the event of the need for a SenTREE unlatch.
- For operations in deep water, an assessment of the need for a Riser Sealing Mandrel (RSM) or Cased Wear Joint (CWJ) must be made.

## 3.2.6 Selection of Well Barrier Working Pressure

### 3.2.6.1 Maximum Potential Wellhead Pressure or Maximum Potential Pressure

Before selecting the correct Working Pressure rating for all Surface Testing equipment, for SubSea equipment or for Drill Stem Testing (DST) tools, it is necessary to know the Maximum Potential Pressure (MPP) which the tool could be subjected to during operations. For Surface Testing equipment installed upstream of the choke, the MPP is equal to the Maximum Possible Wellhead Pressure (MPWHP).

The calculation of the MPWHP or MPP must be made in the early stages of the job design, and because of this there are often a number of uncertainties in the values which are used for the calculation. In order to allow for these uncertainties, and also to allow for other contingencies, it is necessary to have a pressure safety margin between the calculated MPWHP or MPP and the Working Pressure of the equipment which is selected for the job.

#### Definition of MPWHP and MPP

The MPWHP is defined as being the maximum pressure, flowing or shut in, that the surface testing wellhead equipment, installed upstream of the choke, could be subjected to during operations.

The MPP is defined as the maximum pressure, flowing or shut in, that a tool at a specific depth in the well could be subjected to during operations.

The MPWHP or MPP are determined by calculations in conjunction with the client and is the greater of either:

- The maximum undisturbed reservoir pressure minus the pressure of a fluid hydrostatic column between the reservoir depth and the depth of the tool or equipment, where the pressure gradient of the fluid column may be based on the expected reservoir fluid properties, or if a worst case scenario is assumed, the pressure gradient of Methane gas. (0.1 psi/ft).

  or:

- The maximum pressure which will be applied or created at surface or at tool depth during Pressure testing, Bullheading, Fracturing, Pump through closed valve or any other pumping operations.

When calculating the MPP, it is important to consider the hydrostatic head of the different fluids and how they may affect the pressures at the depth of the equipment. The density of the annulus fluid, control fluid (where applicable) and produced fluids must all be considered. These fluids may change due to circulation, disconnections, or other contingencies. In all wells, the Working Pressure of the equipment must not be exceeded even if surface pressure was to be completely bled off for any reason. For dry gas wells, if the surface pressure is bled off the pressure of the hydrostatic column inside the string must be assumed to be zero.

Care must be taken to verify that the differential pressure required to pump through any valve in the string, when added to the pressure which is below the valve, will not exceed the working pressure of the valve, or of any other string component which is above it. The pressure required to pump through a valve must be included in the MPP calculation for the tool concerned, and also in the calculation for the MPP of any tool which is above it in the string.

The possible over-pressuring effect of string manipulations and tool operations must also be taken into account.

For MPP calculation related to SubSea equipment, particularly for deep water wells, consideration for hydrostatic collapse from riser fluid column must be considered. As a minimum, if no other data is available, worst case is to assume gas column in well bore and annulus fluid column in riser. Where applied pressure below a closed BOP ram occurs, the additional surface applied pressure shall also be taken into consideration.

In any case, the reservoir and fluid properties must always be confirmed with the client, and the calculated MPWHP or MPP must also be agreed with, and signed off by, the client.

## Uncertainties and Contingencies in the MPWHP or MPP Calculation

The uncertainties in the MPWHP or MPP calculation and the contingency requirements can be detailed as 4 different factors:

1. Uncertainty of reservoir pressure. The uncertainty on reservoir pressure normally reduces with time as more accurate data is obtained during the drilling phase. Initially, the reservoir pressure is often estimated using a normal or known pressure gradient, typically 0.435 – 0.5 psi/ft, to determine pressure versus depth. There are, however, several geological situations which can lead to an over-pressured formation with, in extreme cases, a pressure gradient of up to 1.3 psi/ft.

   Seismic data, Mud logging, MWD, LWD, Wireline Logging or formation testing can help to predict formation pressure, however only the use of data from all the available sources can help to avoid misleading assumptions and incorrect conclusions.

   The uncertainty of the reservoir pressure is significantly reduced if it is a well which has been previously produced or injected.

2. For Surface and SubSea Equipment, uncertainty of the nature of the fluids to be produced and consequent tubing hydrostatic gradient and pressure estimation at wellhead or at SubSea tool level during build-up.

   This uncertainty is an especially important consideration for deep wells where an error on the gradient can lead to a difference of several hundred psi at wellhead and therefore at subsea tool level.

   The uncertainty of the tubing hydrostatic gradient is significantly reduced in the following three cases:

   a. If a worst case scenario (i.e. the lowest possible hydrostatic pressure) is assumed by using the pressure gradient of methane (0.1 psi/ft) to estimate the column hydrostatic pressure.
   b. If the hydrostatic gradient or the wellhead shut-in pressure is well-known because the well has been previously flowed to surface. (For example, where the well is a production or workover well and no perforations have been added to access a formation which has not previously been produced.)
   c. Where the well is an injection well which will not be flowed and only known fluids will be injected from surface.

   For DST tools, due to the uncertainty of the reservoir pressure, there may also be a degree of uncertainty over the weight of the hydrostatic column of annulus fluid which is above the tool level, and also the weight of the kill fluid when bullheading.

   This uncertainty is an especially important consideration for deep wells where an error on the annulus gradient can lead to a difference of several hundred psi at wellhead and therefore at subsea tool level.

   The uncertainty of the annulus hydrostatic gradient is significantly reduced in the following three cases:
   a. If the hydrostatic gradient is well-known because the well has been previously tested or produced and there are records of the annulus and kill fluids successfully used. (For example, where the well is a production workover well and no perforations have been added to access a formation which has not previously been produced, or where it is a re-entry to an old wellbore.)
   b. Where the well is an injection well which will not be flowed and only known fluids will be injected from surface.

---

3. Pressure required for bullheading in order to kill the well.

   There will always be a small degree of uncertainty over the exact pressure required at surface for Bullheading, Injecting, or Fracturing as it also depends on the pump rate required in order to successfully complete the operations.

---

4. Contingencies such as the differential pressure needed to bullhead through a ball or flapper valve which could have become inoperable when in the closed position. The additional pressure required for pumping through a closed and inoperable valve is a fixed value which depends on the type and size of valve.

   The depth at which the DST and SenTREE tool is located, and also the density of the potential fluids in the test string, will affect the hydrostatic pressure acting on top of the valve. Therefore the pressure which would have to be applied at surface in order to bullhead through a closed valve will vary from job to job and will have to be estimated at the time of job design.

   Care must be taken to verify that the differential pressure required to pump through any valve in the string, when added to the pressure which is below the valve, will not exceed the working pressure of the valve, or of any other string component which is above it.

   In the event of a failure in the SenTREE umbilical or downhole control system, it would be possible to mechanically unlatch and pull the latch and umbilical back to surface to effect repairs, but the worst case scenario, that of having to pump through a closed ball valve, should always be considered.

**Table 3-1: Upper limits of the Differential Pressures Required to Pump through Valves**

| **Upper limits of the Differential Pressures Required to Pump through Valves** | | | |
|---|---|---|---|
| | **3” string** | **6” string** | **7” string** |
| **Lubricator valve (1)** | 500 psi | 500 psi | 600 psi |
| **EZ-Valve (2) (3)** | 3,000 psi | N/A | N/A |
| **SenTREE Ball Valve (2) (4)** | 200 psi (5) | 1,200 psi | 1,200 psi |

The values for any 3rd party lubricator or Safety Valves which are to be run in the string must be confirmed with the valve manufacturer at the time of job design.

1. Once shifted to a partly open position, the Lubricator Valve will stay open, but differential pressure must be created by the rate at which fluid is pumped through the valve in order to open it further.
2. The EZ-Valve and the SenTREE Ball Valve will automatically close again if the differential pressure drops below these values.
3. Due to the higher pump through pressure required for the EZ-Valve, the use of 5 k surface testing wellhead equipment if an EZ-Valve is in the string is not recommended.

4. There is also a small amount of differential pressure required to pump through the SenTREE flapper valve, but this is a purely nominal value compared to the pressure required to pump through the ball valve.

---

**Note**

The SenTREE 3 ball does not rotate into the open position. If the differential from above the ball to below the ball is more than 200 psi then the seal will disengage and allow fluids to be pumped through.

---

**Caution**

Potential Severity: Light
Potential Loss: Information
Hazard Category: Pressure

It is not normally possible to pump through a closed Retainer Valve. However the annular preventer can be closed, and annulus pressure applied to the valve in order to open it.

---

## Safety Margin between MPWHP or MPP and the Equipment Working Pressure Rating

In order to allow for the uncertainties and contingencies described above a safety margin is required between the MPWHP or MPP and the Working Pressure rating of the equipment.

The minimum safety margin for surface, subsea and downhole pressure containing equipment which must be used at the time of job design, unless managed by the exemption process, is 20% of the Working Pressure rating of the equipment.

This means that the expected MPWHP or MPP must not exceed 80% of the Working Pressure rating of the equipment which is planned for the job.

In the case of a job where an EZ-Valve is planned, the safety margin between the MPWHP and the Working Pressure of the surface testing wellhead, as well as the safety margin between the MPP at EZ-Valve level and the Working Pressure of the EZ-Valve must be the greater of either 3,500 psi (so as to allow for 3,000 psi to pump through the valve, plus an additional 500 psi safety margin), or 20% of the surface testing wellhead equipment working pressure rating.

For any job where a SenTREE and/or a downhole valve is run in the string, the safety margin of surface equipment, subsea equipment and downhole equipment must be sufficient to accommodate enough pressure to pump through a closed SenTREE or downhole ball valve, plus an additional 500 psi margin, or be at least 20% of the equipment pressure rating, whichever is larger.

This is not a de-rating of the equipment. It is planning so as to accommodate unknown quantities, errors in estimation or measurement, and unscheduled events, within the confines of the Working Pressure rating, so that potential Well Integrity issues are prevented.

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**Note**

Employing the exemption process allows equipment to be deployed with a reduced safety margin below 20%. The process it to highlight and manage the reduced margins and ensure that at no time during any operation will the Working Pressure or tensile ratings be compromised.

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### Exemption Requests for a reduced Safety Margin

For borderline cases (i.e. the safety margin is only just under the minimum requirement), or where availability of higher rated equipment is an issue, it may be possible to plan a job with a smaller safety margin by using the exemption process and showing in the exemption that at least one of the four factors described in Section 3.2.6.1 Uncertainties and Contingencies in the MPWHP or MPP Calculation can be reduced or discounted and that there is a high degree of certainty or control over the pressures which will be reached at surface. This would be by documenting any of the following:

1. Documented certain or accurately measured reservoir pressure. (for example in an existing production or injection well).
2. Known fluids used for the pressure gradient, or the use of the Methane Gas “worst case scenario”.
3. No Lubricator Valve or EZ-Valve in the string, no SenTREE 3 at a depth of less than 400 ft, and no large bore SenTREE in the string at a depth of less than 2,500 ft.

Potential Severity: Light
Potential Loss: Information
**Caution** Hazard Category: Pressure

A reduction in the safety margin can only be considered in a case where it can be demonstrated through calculations that the MPWHP or MPP, plus the reduced safety margin, will never in any case, including during bullheading, or other pumping operations, exceed the WP of the equipment.

If a job is to be planned with **a safety margin** which is **between 20% and 10%** of the equipment working pressure rating, the **exemption** must be **approved by the Geomarket Testing Operations Manager** before the job planning is finalized.

The exemption submitted must include:

- A HARC analysing risks such as the degree of uncertainty on the pressures and temperatures which will be encountered, the properties of the fluids which will be produced, the effect of string manipulations, killing procedure, etc. and the possibilities of mechanical failure along with assessment of the actions to be taken in the event of their occurrence. The worse case scenarios shall always be considered.
- Documentation which supports the basis on which any calculations have been made. (Such as MDT data, Pressure and Temperature logs, information about previous jobs performed in the same reservoir, etc).
- Details of the string design including Pressure and Temperature ratings of all components and minimum tensile load ratings.
- The RITE History Cards of the equipment to be used.
- The exemption must also address the requirements for the Well Site Pressure Test. See sections 4.5.1: Basic Wellsite Pressure Test (WPT), 5.7.1: Basic Wellsite Pressure Test Rules and 6.5.1: Basic Pressure Test Rules.

If a job is to be planned with **a safety margin** which is **below 10%** of the equipment working pressure rating, the **exemption** described above must also be **approved by the Testing Services Area VP** before the job planning is finalized.

If the exemption for a safety margin which is less than 10% of the equipment Working Pressure is approved, DST and Subsea equipment to be run in the string must also undergo a Q-Check prior to load out and SWT equipment require pre job maintenance called an Integrity Test, which is detailed below.

---

**Warning** Potential Severity: Serious
Potential Loss: Information
Hazard Category: Pressure

Any exemption for a job where the safety margin between the MPWHP or MPP and the equipment Working Pressure rating is planned at less than 500 psi will not be approved.

---

### Surface Testing Wellhead Equipment Integrity Test Requirements:

The Integrity Test shall include the following steps:

- Replacement of all seals and consumables including fittings.
- Inspection of all sealing areas.
- Inspection of the thread and sealing areas of all fittings points (NPT /Autoclave).
- NDT inspection of the load bearing threads and any below flowhead crossovers.
- Thickness test at critical points to confirm there is no abnormal erosion of the equipment.
- Body pressure test to 1.1 x WP of the equipment.

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**Warning** Potential Severity: Serious
Potential Loss: Information
Hazard Category: Pressure

Pressure tests above WP of Subsea or surface well testing equipment must only be carried out in a Pressure test bay meeting the requirements of to this POM. DST equipment WP and TP are the same and shall never be tested above WP. Pressure tests at the wellsite must never exceed the WP of the lowest rated piece of equipment undergoing the test. It is strongly recommended that any pressure test above 80% of the WP at the wellsite should have at least 2 separate calibrated means of recording the test for redundancy.

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- Operating test at Working Pressure.
- Review of Quality File (to confirm it fully represents the equipment being maintained).
- The RITE record of the assets involved must be updated with this additional maintenance, and the history cards from RITE attached to the exemption.

If the equipment for the job has been unused since manufacture, has had a reception test performed within the last 6 months and recorded in RITE, and since the reception test been properly stored to avoid corrosion, then the requirement for the Integrity test is waived, but the routine pre job FIT and pressure tests must still be performed and the RITE history card must still be attached to the exemption request.

If the equipment for the job has undergone a major survey (for Surface Testing equipment) or a Q-check (for subsea and DST equipment) within the last 6 months which is fully recorded in RITE, no jobs have been performed with it since, and it has been properly stored to avoid corrosion, then the requirement for the Integrity test or a new Q-Check is waived, but the routine pre job FIT and pressure tests must still be performed and the RITE history card must still be attached to the exemption request.

**Warning**
Potential Severity: Serious
Potential Loss: Information
Hazard Category: Pressure

In order to minimize the risk of internal corrosion, pressure test fluids must be properly drained from the equipment on completion of the test and the equipment stored, with any valves in the open position, in a dry, well ventilated area, and ideally under a high roof.

## Summary of MPWHP or MPP versus Equipment Working Pressure Rating

**Table 3-2: MPP Versus Equipment Working Pressure Rating**

| Summary of MPWHP or MPP versus Equipment Working Pressure | | | | |
|---|---|---|---|---|
| **Exemption Level** | **Equipment Working Pressure** | | | |
| | **5 kpsi** | **10 kpsi** | **15 kpsi** | **20 kpsi** |
| No exemption will be granted when: | MPWHP or MPP > 4500 psi | MPWHP or MPP > 9500 psi | MPWHP or MPP > 14,500 psi | MPWHP or MPP > 19,500 psi |
| Exemption approved by the Testing Services Area VP is required and an integrity test for SWT or Q check for DST & Subsea equipment must be performed when: | no exemption allowed for MPWHP or MPP > 4500 psi | 9,500 psi > = MPWHP or MPP > 9,000 psi | 14,500 psi > = MPWHP or MPP > 13,500 psi | 19,500 psi > = MPWHP or MPP > 18,000 psi |
| Exemption approved by the Geomarket Testing Operations manager is required when: | 4,500 psi > = MPWHP or MPP > 4,000 psi | 9,000 psi > = MPWHP or MPP > 8,000 psi | 13,500 psi > = MPWHP or MPP > 12,000 psi | 18,000 psi > = MPWHP or MPP > 16,000 psi |

| Summary of MPWHP or MPP versus Equipment Working Pressure | | | | |
|---|---|---|---|---|
| Exemption Level | Equipment Working Pressure | | | |
| | 5 kpsi | 10 kpsi | 15 kpsi | 20 kpsi |
| Exemption approved by the Geomarket Testing Operations manager is required **if an EZ-Valve is in the string** and when: | MPWHP > 1,500 psi (EZ-Valve not recommended) | MPWHP > 6,500 psi | MPWHP > 11,500 psi | n/a |

*MPWHP = Maximum Potential Wellhead Pressure
* MPP = Maximum Potential Pressure.

### Comparison Example 1 MPWHP:

There are two wells. They have the same expected reservoir pressures, fluids, and vertical depth. The MPWHP is calculated as being 3,420 psi for both of them, and there is no $H_2S$. However, one well is onshore, and one well is offshore and drilled by a jack-up.

From Table 4-5: Number of Valves versus Well Parameters in section 4.4.2 an EZ-Valve or SCSSV is mandatory for the offshore well, but optional for the land well.

The Offshore well is therefore planned with the EZ-Valve in the string, but for the land well, the client opts to run the string without one.

For the Offshore well, because of the EZ-Valve, it would be necessary to have an exemption approved by the Geomarket Testing Operations manager before a well test with 5 kpsi rated surface testing wellhead equipment can be planned because the MPWHP is above the 1,500 psi shown in the table. However, the job can be planned with 10 kpsi, 15 kpsi or 20 kpsi rated surface testing wellhead equipment without any exemption.

For the onshore well, there is no EZ-Valve, so the well test can be planned with 5 kpsi (or 10 kpsi, 15 kpsi or 20 kpsi) rated surface testing wellhead equipment without the need for any exemption because the MPWHP is below 4,000 psi.

### Comparison Example 2 MPWHP:

There are two wells. Both are exploration wells offshore in deep water and will be tested from Semi submersible rigs. Because, in both cases, the SenTREE 3 will be at a depth of more than 400 ft, the pressure at surface which would be required to pump through them can be ignored.

The MPWHP for the first well is calculated using client supplied estimates of reservoir pressure and fluid properties and the result is a maximum pressure of 8,500 psi. This is above the 8,000 psi figure where an exemption is required before planning the job with 10 kpsi rated equipment, so it means that unless it can be confirmed, either by measurements or some other method, that the clients estimates of the reservoir pressures and produced fluids are precise, and in which case an exemption could be justified, the job must be planned with 15 kpsi or 20 kpsi rated surface testing wellhead equipment.

The MPWHP for the second well is calculated using an estimate of reservoir pressure based on pressures obtained while drilling other wells in the area, and the worst case scenario of a Methane gradient to surface. This results in a, MPWHP of 9,100 psi. In this case it can be demonstrated that the calculated MPWHP will be very close to, or even higher than the pressure which will be encountered. There is therefore justification for an exemption to be approved by the Testing Services Area VP which would allow 10 kpsi rated surface testing wellhead equipment to be planned for the job. However, if it is, then the surface welltest equipment must also undergo an Integrity test during the job preparation phase.

### Example #3 MPP:

Example of Maximum Possible Pressure (MPP) calculation with the following conditions:

- Formation Pressure = 6600 psia.
- Well Head Shut In Pressure = 5300 psia.
- Sentree depth = 650 ft.
- Fluid gradient inside tubing with gas = 0.1 psi/ft.
- Kill fluid = 10.8 #/gl.
- Valve pump through pressure if required = 1200 psi.

A maximum surface pressure of 5300 psi is known, so it will be necessary to find the pressure at the Sentree level. Pressure at the Sentree level = 5300 psi + (0.1 psi/ft gas gradient x 650 ft landing string = 65 psi) = 5365 psi.

In the worst case scenario, the hydraulic control is lost and the ball closes. To kill the well, pumping through the ball will be necessary. It is known that the pressure below the Sentree valve is 5365 psi so adding 1200 psi pump through pressure gives a total of 6565 psi at the Sentree level.

The MPP in this case would be 6565 psi. The tells us that the 10 kpsi WP can be used with an MPP up to 8 kpsi without any exemption so 10 kpsi equipment will be used in this case.

**Note**

In case of project specific equipment with Working Pressure not shown in , check that WP is at least equal to MPP times 1.2 safety margin. If not, an exemption and eventually a pre-job Integrity test or Q-check might be required.

## 3.3 Validation and Acceptance of Well Barriers

On arrival at the wellsite, Testing Services supplied well Barrier Elements must be physically checked for length, OD, ID, and operating specification before use.

Once the Well Barrier Envelope has been constructed and installed, its integrity and function shall be verified by means of:

- Leak or inflow testing by application of a differential pressure. Whenever possible this should be performed in the direction of the flow. Leak testing must be carried out prior to the elements' first exposure to pressurized well fluids. It must also be performed after replacement of any of the pressure retaining elements of the Well Barrier, or when there is suspicion of a leak. It will also be required routinely during operations, such as when performing multiple well interventions with Coiled Tubing, Electric Line, or Slickline due to the need to verify the integrity of the WHE after each make up. Any leak or inflow test must subject the barrier envelope to a differential pressure which at least equals that to which it will be subjected when exposed to well fluids or gasses, and be performed for a minimum duration of 5 minutes of stabilized recorded pressure.
- Function testing of well barrier elements which require activation. Function testing must be carried out prior to the elements' first exposure to pressurized well fluids. It should also be performed after replacement of any of the pressure retaining elements of the Well Barrier, or when there is suspicion of a leak. It may also be required routinely, such as when performing multiple well interventions with Coiled Tubing, Wire, or Slickline due to the need to verify the integrity of the WHE after each make up.
- Verification by other specified methods which may be defined in the individual Well Barrier Element Acceptance Criteria (WBEAC) documents.

Documented reports of Barrier Testing shall be signed and retained in the job files. Details of the barrier element(s) or envelope being tested, along with the date, time and location must be given. Any pressure testing of barriers shall be recorded by using a hard copy device, either a circular plot from a pressure recorder or a hard copy log from a computer device. One axis shall be scaled in pressure units and the other shall be scaled in time. If a chart recorder is used, it shall be fitted with a clock rotation speed appropriate for the duration of the test. Two- to four-hour clocks are recommended for the standard 5 to 15 min hydrostatic tests.

### 3.3.1 Additional Validation and Acceptance Criteria for Subsea Operations

Specifically for Subsea operations, the BOP stack dimensions used for the design of the space out must also be re-checked.

In the case of SenTREE 3 operations it will normally be necessary to perform a "dummy run" with an assembly to verify the BOP ram closure position(s) on the slick joint. Refer to the relevant Subsea Operations and Maintenance manuals for further details of the requirements and processes.

For operations involving large bore SenTREE equipment, an onshore acceptance test, witnessed and signed by a client representative or a client appointed 3$^{rd}$ party, is considered as being an integral part of the validation process. Upon receipt of the equipment offshore, the crew must confirm, piece by piece, that what has been received is the same equipment as was used for the onshore acceptance test.

### 3.3.2 Additional Validation and Acceptance Criteria for DST Operations

When an underbalanced DST is planned:

- Once the production packer is set in the liner, an inflow test of the production liner lap (if installed) shall be done with the minimum possible hydrostatic column of fluid in the well in order to put the maximum possible differential across the liner lap. The production string shall also be leak tested to the maximum expected pressure with the annulus fluid to be used for the test already in place.
- Kill fluid should be readily available in tanks for displacement of the entire well volume.

## 3.4 Monitoring Well Barriers

All parameters relevant for the condition and status of elements intended to prevent uncontrolled flow from the well shall be monitored.

Installed barrier elements shall be monitored during well activity to the maximum extent possible in order to verify the elements status. This should be done using one or more of the following methods:

- Through pressure observation on the elements downstream side.
- Through visual observation.
- Through recording of pressures and volumes (where gains or losses would indicate a possible leak).
- Through pressure and/or temperature trend analysis (To ensure that the specification of any of the Well Barrier Elements will not be exceeded).
- Through repeat pressure testing at predefined points.

Typically the monitoring requirements will be:

| Method | Tool Type | | |
|---|---|---|---|
| | **Flowhead** | **Sub Sea** | **DST Tools** |
| | | | |
| Pressure observation on the downstream side | | ✓* | V* |
| Visual observation | ✓ | | |
| Recording of pressures and volumes | | ✓ | ✓ |
| Pressure and/or temperature trend analysis | ✓ | ✓ | ✓ |
| Repeat pressure testing at predefined points | ✓ | ✓ | |

* Only applicable when the valves are closed.

Methods and frequency for verifying the condition of the well barrier envelope and/or well barrier elements shall be defined and described in the job operating procedures, with documented records of their status and condition being created or updated at the time of verification and kept in the job files.

All instrumentation used for required monitoring of parameters shall be frequently checked and calibrated in accordance with the manufacturer's specifications. Calibration records for the instrumentation to be used must be available prior to commencing operations.

If a barrier element under the responsibility of Schlumberger fails, no operation shall continue other than those which have the objective of re-establishing the barrier in which the element has failed, or activating an alternative barrier.

In the event of a failure or loss of a well barrier, immediate measures shall be taken in order to prevent escalation of the situation.

If a plan is made, or an instruction given to continue the operation with a lost barrier, there shall be an obligation on TS personnel to stop the job by initiating a Q-stop.

For potential incidents with likely occurrence or high consequence there should be contingency or well control preparedness plans made available and discussed as necessary prior to commencement of the activity. Such plans shall describe how an impaired or lost well barrier can be reinstated or an alternative well barrier can be established.

## 3.5 Re-establishing Well Barriers

When there is a barrier failure, no activities other than those required for the sole purpose of restoring the barrier or placing the well in a safe condition, if necessary using a previously redundant barrier to accomplish the work, shall be performed. Such work shall be subject to risk evaluation.

Activities and operations other than those required for the sole purpose of restoring the barrier or placing the well in a safe condition MUST also cease, when:

- A weakened or impaired well barrier envelope or element is identified.
- The hydrocarbon gas level in air exceeds the specified limit as applicable to any of the hazardous zoning definition and limits.
- There is a high probability for exceeding the allowable operating limits of well control equipment and other critical equipment.

In the event of the failure of a Well Barrier or Well Barrier Element during a DST, it is most likely that the installation or engagement of an alternative barrier will be needed to regain control, even as a temporary solution, prior to killing the well and pulling the string back to surface so that the failed Element(s) can be replaced. Contingency plans for the failure of a well barrier element or envelope should be included in the job programme.

### 3.5.1 Re-establishing Fluid Barriers

The methods for killing the well or re-establishing a fluid well barrier shall be defined and known prior to the execution of any activities where the fluid column is one of the well barriers, part of a Well Barrier or Well Barrier Element, or is defined to be a component in a contingency well barrier. These methods should be detailed in the job programme.

### 3.5.2 Re-establishing Mechanical Barriers

If a mechanical barrier is found to have failed, the following alternatives should be considered in the given order:

- Attempt to restore the barrier.
- Install or engage a different barrier.

## 3.6 CAT Verification and Well Integrity Check List

### 3.6.1 Compliance Audit Tool (CAT) Questions

CAT questions designated as LTO (License to Operate) are the highest category of questions in the Audit. If non compliance to any of the LTO questions is found it means that operations may be shut down until the issues are corrected.

3 of the LTO questions are directly related to Well Integrity. They are:

- "Is any machining/welding on any asset considered as Well Control Barrier (ref. TS Well Integrity standard, in TS Well Integrity InTouch content ID 5348424) carried out by a Schlumberger Product Center or by an approved workshop under a OneCAT RFQ process managed through a Schlumberger Product Center."

**Note**
listing of the Equipment Codes which are Testing Services Well Barrier Elements is available at InTouch content ID 5595702.

- "Is any tubular crossover (any crossover below flowhead) procured through a RFQ submitted to a Schlumberger Product Center ?"
- "Are the SenTREE components physically measured and matched with the stack-up drawing as signed off by the client prior to mobilization ?"

The first 2 of these 3 questions are about ensuring that traceability and certification are maintained for all Well Barrier elements in accordance with POM requirements.

The third question ensures that, on the information we have been given, the SenTREE will fit into the BOP stack and that the space out allows for BOP ram closure on the slick joint, and, in the event of a riser unlatch, either across the top of the SenTREE valve when the SenTREE latch has been unlatched and pulled back, or in the case of the need to shear the string at the shear sub, across the top of the latch. These requirements are essential to maintain Well Integrity.

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**Note**

Once on board the rig, the BOP dimensions should be re-confirmed as described in section 3.3: Validation and Acceptance of Well Barriers.

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There is also a CAT 1 question:

“Is the location tracking the serial number of all critical parts in Assets considered as Well Control Integrity Barriers? Is location strictly following preventative maintenance instructions as per O&M Manual for Assets listed as Well Control Integrity Barriers?”

For more information on “Critical Parts”and the Traceability (or tracking) requirements, please refer to sections 3.7.6: Critical parts of Manufactured Well Barrier Elements and 3.7.8: Traceability of this document.

## 3.6.2 Well Integrity Checklist

In order to verify that all the necessary steps have been taken to ensure that effective Well Barriers (see Figure 3-4: Well Barrier Elements) are in place, a job specific checklist must be created and added to the SDP. Below is an example of such a checklist.


**Figure 3-4: Well Barrier Elements**

*This example checklist is not for any specific job scenario and should only be used as a guide for the preparation of job specific ones.*

**Design:**

**General Design Points:**

- Is the Maximum Shut In Wellhead Pressure well defined?
- Is the Maximum allowable annulus surface pressure well defined?

- Is the Maximum Downhole Temperature defined?
- Are the Well fluid properties defined?
- If fluid is to be used as a barrier can it be monitored and maintained, and will a reserve of fluid be immediately available?
- Have environmental criteria for shutting down operations been defined, agreed with the client, and included in the job programme? (E.g. Wind, Sea conditions, ambient temperature, etc)
- Prepare a well barrier schematic illustration and identify the barrier elements that you are responsible for. Then list the other barrier elements in the schematic and denote the responsible parties.

**Primary Barrier Specific:**

- Are all primary barrier elements those elements which are in direct contact with the pressure source?
- Is the pressure burst rating of the primary barrier elements sufficient?
- Is the metallurgy of the primary barrier elements suitable for the environment?
- Where applicable are the thread types used on the primary barrier elements suitable for gas exposure?
- Has the barrier acceptance criteria been defined in writing and added to the job programme?
- For Subsea wells, have the SenTREE and marine riser unlatch criteria been defined, documented, agreed with the client, and included in the job programme?

**And Either:**

- If intervention is planned, is there sufficient height inside the riser / Lubricator sections to accommodate the proposed toolstrings above the (Upper) Lubricator Valve if a second Lubricator Valve, or an SSSV, SenTREE or DST tester valve is present below it?

  or

- If intervention is planned, is there sufficient height inside the riser / Lubricator sections to accommodate the proposed toolstrings above the Swab Valve if no Lubricator Valve is present in the string, or if no SSSV, SenTREE, or DST tester valve is present below the Lubricator Valve?

**Secondary Barrier Specific:**

- Are there any common barrier elements (consider all components from the wellhead connector and up)?

- Is the secondary barrier representing the last resort?
- Is there a need to prepare a documented contingency plan to describe the activation sequence of any alternative (or intermediate) barriers before you activate the ultimate secondary barrier?
- Is the secondary barrier closing in the well as close to the inflow source as possible?
- Is the pressure burst rating of the secondary barrier elements sufficient?
- Is the metallurgy of the secondary barrier elements suitable for the environment?
- Are the thread types of the secondary barrier elements suitable for gas exposure where applicable?
- Can the BOP shear rams cut the shear joint or tubing above the latch assembly?
- Have the criteria and procedures for shearing the tubing been defined, agreed with the client, and included in the test programme?
- Has the barrier acceptance criteria been defined in writing and added to the job programme?

**Preparation:**

- Are any elastomer seals suitable for the environment in which they are used?
- Has the Casing / Liner weight and ID been verified?
- Is the packer dressed for the correct Casing/Liner weight and ID?
- If Subsea equipment is to be used, has the client agreed to, and signed off on, the stack up drawing showing the position of the Ez-Valve or SenTREE in the BOP stack?

**Rig Up:**

- Are the BOP rams the correct size for the slick joint?
- For SenTREE 3: Has a dummy run been performed with the SenTREE to verify the space out?
- For SenTREE 7 & HP: Have all the parts been checked against the BOM of the onshore acceptance test?
- Have the SenTREE and Lubricator valves been function tested after installation in the string?
- Have all Schlumberger provided barrier elements been leak tested after installation in the well?

**Monitoring:**

- Annulus Pressure shall be monitored at all times.
- The volume of annulus fluid in the riser will be monitored at all times.
- The Tension held on the Flowhead will be monitored at all times.
- The surface wellhead pressure shall be recorded during all well activities.

# 3.7 Certification, Traceability and Maintenance

The manufacture, maintenance, transfer and implementation of Well Barrier elements shall be defined, documented, controlled, validated and recorded.

## 3.7.1 Procurement

Manufactured Well Barrier Elements must be procured in accordance with POM Section 2.3: Procurement (i.e. They may only be procured through a OneCAT RFQ, from SRPC External Sales, or direct from a Schlumberger Product Centre.)

## 3.7.2 Remanufacturing or Re-Cut of Threads

Any remanufacturing or re-cut of the threads on a tool joint, or crossover procured direct from, or supplied under the control of, a Schlumberger Product Centre, may only be performed after first having obtained documented permission from the Schlumberger Product Centre responsible for the tool or Crossover. The work must be performed either by the product centre itself, or under the Local Manufacturing, Repair and Procurement process described in Appendix C.

Any remanufacturing or re-cut of the threads on a crossover originally purchased through the Regional Manufacturing process may only be performed in accordance with the procedures detailed in Appendix C.

## 3.7.3 Rented Equipment

Where Well Barrier Elements are items of equipment rented by Schlumberger they must conform to the requirements of POM Section 2.3.2: Rented Equipment.

## 3.7.4 Client Supplied Equipment

Where Well Barrier Elements are items of equipment which are owned or supplied by the client, they must conform to POM section 2.3.3: Client Supplied Equipment.

## 3.7.5 Non Schlumberger Contracted Service Company Equipment

Where Well Barrier Elements are supplied by other service companies contracted directly by the client they must conform to POM section TBA.

## 3.7.6 Critical parts of Manufactured Well Barrier Elements

During the design of tools and equipment which may be used as Well Barrier Elements, components of the tool which are critical to its function, performance or integrity are identified. This is a mandatory requirement when designing tools to meet certain design codes, but optional for others.

The components of the tool which have been identified as critical may have their individual detail drawings listed separately on the equipment type approval certificate. They are ringed in Red on the following example:

DNV

# DET NORSKE VERITAS

# TYPE APPROVAL CERTIFICATE

**CERTIFICATE NO. D-3501**
This Certificate consists of 5 pages

*This is to certify that the*
**WELL TESTING EQUIPMENT**

*with type designation(s)*
**SENTREE 7, SUBSEA, LUBRICATOR VALVE**
**S7LV, P/N 100521129 REV. AD**

*Manufactured by*
**SCHLUMBERGER RESERVOIR COMPLETIONS**
**ROSHARON, TX - USA**

*is found to comply with*
DNV's Offshore Standard DNV-OS-E101 "Drilling Plant" October 2006

*and Det Norske Veritas' understanding of the implementation and interpretation of:*
PSA's "Regulations relating to the Design and Outfitting of Facilities etc. in the Petroleum Activities (the Facilities Regulations)," Chapter IV, Last Amended 20 December 2007

*Application*
See design limitations on page 2

*Place and date*
Houston, 2009-1-28
*for* DET NORSKE VERITAS (USA) INC.

Brandon Caraway
*Head of Section*

DET NORSKE VERITAS • 1864 •

*Local Office*
DNV Houston

*This Certificate is valid until*
2013-1-31

Andrea French
*Project Engineer*

**Notice: This Certificate is subject to terms and conditions overleaf. Any significant change in design or construction may render this Certificate invalid. The validity date relates to the Type Approval Certificate and not to the approval of equipment/systems installed.**

If any person suffers loss or damage which is proved to have been caused by any negligent act or omission of Det Norske Veritas, then Det Norske Veritas shall pay compensation to such person for his proved direct loss or damage. However, the compensation shall not exceed an amount equal to ten times the fee charged for the service in question, provided that the maximum compensation shall never exceed USD 2 million. In this provision "Det Norske Veritas" shall mean the Foundation Det Norske Veritas as well as all its subsidiaries, directors, officers, employees, agents and any other acting on behalf of Det Norske Veritas.

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Form No.: 20.90a Issue: January 98

Page 1 of 5

DNV

ID No.: 262.1-005903-12
Cert. No.: D-3501
File No.: 523.72
DNV Project No.: 47000069

**Product description**

- "LUBRICATOR VALVE ASSY, SENTREE 7, W CI END SUB"

**The following design codes/standards were used as references**

- API 6A, *Wellhead and Christmas Tree Equipment*, 19th Edition
- NACE MR0175/ISO 15156 2001: Material for use in H2S containing environments in oil and gas production. Parts 1-3.

**Application/Limitations**

| | | |
|---|---|---|
| - Minimum Design Temperature | : | -20 °F |
| - Maximum Design Temperature | : | 325 °F |
| - Maximum Working Pressure | : | 10,000 psi |
| - Maximum Testing Pressure | : | 15,000 psi |
| - Hanging Loads | : | 1,500,000 $lb_f$ at 0 psi |
| | : | 400,000 $lb_f$ at 10,000 psi |
| - Torque | : | 40,000 ft- $lb_f$ at 0 psi |
| - Service | : | Sour/ $H_2S$ |

**Type Approval documentation**

Drawings:

| Description | Part/Rev. | Dwg./Rev. | Material |
|---|---|---|---|
| - ASSEMBLY LUBRICATOR VALVE | 100521129/ AD | 100521129D / AD | Assy. |
| - MANDREL, LUBRICATOR VALVE | 100019623 / AB | 100019623 / AB | SH355317/ T6002116 |
| - RING, STOP, MANDREL,LUBRICATOR VALVE | H355431 / AL | H355431 / AL | SH355317 |
| - OPERATOR, LUBRICATOR VALVE | 100050589 / AC | 100050589 / AC | 100160002 |
| - RING, STOP, OPERATOR - LUBRICATOR VALVE | 100050586 / AD | 100050586 / AD | 100160002 |
| - RETAINER, SEAL, BALL VALVE | 100121727 / AA | 100121727 / AA | CMS-Z1KGK.0 |
| - BALL, VALVE, CLOSED, 7.38 BORE | 100067000 / AC | 100067000 / AC | 100237403 |
| - KEY TORQUE, LUBRICATOR VALVE | T6001102 / AD | T6001102 / AD | SH355317/ T6002116 |

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Form No.: 20.90a Issue: January 98 Page 2 of 5

| | |
|---|---|
| ID No.: | 262.1-005903-12 |
| Cert. No.: | D-3501 |
| File No.: | 523.72 |
| DNV Project No.: | 47000069 |

| Description | Part/Rev. | Dwg./Rev. | Material |
|---|---|---|---|
| - PIN, LEFT HAND LUBRICATOR VALVE OPERATOR | T6001771 / AD | T6001771 / AD | CMS-Z1R1J.0 |
| - PIN, RIGHT HAND LUBRICATOR VALVE OPERATOR | T6001772 / AD | T6001772 / AD | CMS-Z1R1J.0 |
| - MATCH DRILL S7LV VALVE SENTREE 7 | 100521146 / AA | 100521146 / AA | SH355317/ T6002116 |
| - SUB, CAP, END, LUBRICATOR VALVE | H355422 / AP | H355422 / AP | SH355317/ T6002116 |
| - SUB, CHEMICAL INJECTION-LUBRICATOR VALVE | 100065016 / AD | 100065016D/ AD | SH355317/ T6002116 |
| - HOUSING, LUBRICATOR VALVE | 100521176 / AB | 100521176D/ AB | 100463728 |

Material Specifications:

| Material | Rev. | Description |
|---|---|---|
| - SH355317 | AP | AISI 4130/4140, NACE 80K YIELD |
| - T6002116 | AE | 8630 Modified, 80K yield |
| - CMS-Z1KGK.0 | AJ | 925, 110 KSI MIN YS, 30-38 HRC |
| - CMS-Z1R1J.0 | AD | CMS-Z1R1J.0, ALLOY 725, ANNEALED AND AGED 140 KSI MIN YIELD STRENGTH (35-43 HRC) |
| - 100160002 | AE | 17-4 PH SS (UNS S17400) H-DOUBLE 1150 105 KSI MIN YIELD STRENGTH |
| - 100237403 | AB | 718 (UNS NO7718) Annealed & Aged, 120 KSI Min Yield |
| - 100463728 | AB | CMS-Z28GN.0, 2-1/4 Cr-1Mo, 90 KSI YS (ASTM A182, F 22 mod.) |

| Material | Min. Yield | Avg. Charpy @ -20 °F | Surface NDE | Volumetric NDE | Max. Hardness Rc |
|---|---|---|---|---|---|
| - SH355317 | 80,000 psi | 31 ft-lb$_f$ | 100 % | 100 % | 22 |
| - T6002116 | 80,000 psi | 31 ft-lb$_f$ | 100 % | 100 % | 22 |
| - CMS-Z1KGK.0 | 110,000 psi | 31 ft-lb$_f$ | 100 % | 100 % | 38 |
| - CMS-Z1R1J.0 | 140,000 psi | 31 ft-lb$_f$ | 100 % | 100 % | 43 |
| - 100160002 | 105,000 psi | 31 ft-lb$_f$ | 100 % | 100 % | 33 |
| - 100237403 | 120, 000 psi | 31 ft-lb$_f$ | 100 % | 100 % | 40 |
| - 100463728 | 90,000 psi | 31 ft-lb$_f$ | 100 % | 100 % | 22 |

Calculations:

- 100575161 Rev. AB, CALCULATIONS, SenTREE 7, LUBRICATOR VALVE ASSY WITH

ID No.: 262.1-005903-12
Cert. No.: D-3501
File No.: 523.72
DNV Project No.: 47000069

END SUB, P/N 100521129

**Fabrication Procedures**

Test Procedures:

1. Hydrostatic pressure testing to be conducted at test pressure for duration of 3 minutes and 15 minutes
2. Test according to SENTREE 7 LUBRICATOR VALVE FACTORY ACCEPTANCE TEST PROCEDURE, 100525951 Rev. AB

NDE Procedures:

3. API 6A "Specification for Wellhead and Christmas Tree Equipment", 19th Edition. PSL 3

Welding Procedures:

4. N. A.

Schlumberger Specifications:

| Doc. No. | Rev. | Title |
|---|---|---|
| SH355254 | AN | Final Inspection for Subsea Critical Pressure Containing or Load Bearing Parts |
| SH710505 | AE | Marking of Parts for Identification |
| SH355632 | AH | Quality System for Subsea Products |

**Prototype testing**

N.A

**Marking of product**

For traceability to this Type Approval Certificate the products are as a minimum to be marked as follows:

1. "NV D-3501"
2. Serial Number
3. Manufacturer's name and trademark
4. Safe Operating Loads

**Certificate retention survey**

N.A.

ID No.: 262.1-005903-12
Cert. No.: D-3501
File No.: 523.72
DNV Project No.: 47000069

DNV

**Documentation to be accompanied with each product/delivery**

1. Data book index
2. Equipment name, number, purchaser, etc.
3. Manufacturer's statement of compliance
4. Assembly drawing
5. Actual material certificates as purchased and Charpy impact test records as applicable
6. Heat treatment records/charts when applicable
7. Load, pressure and performance test reports
8. DNV Product Certificate
9. DNV Type Approval Certificate

**Other conditions/comments**

N.A.

END OF CERTIFICATE

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Form No.: 20.90a Issue: January 98 Page 5 of 5

They are also flagged in the engineering database, and field users are able to view which components are critical for any given tool by looking at the Bill of Materials (BOM) in OneCAT, where critical items are flagged with a check mark in the column headed “Barrier Equipment Key Component”.


**Figure 3-5: Barrier Equipment Key Component**

A summary listing of the critical components or parts may also appear in the equipment Quality file and act as an index for the certification documentation of the items concerned.

For example:

| **PART NUMBER: 100521129** | **SERIAL NUMBER:** S7LV-CA_111012 |
|---|---|

| CERT. # | Description | PART # | Trace Number | MATERIAL | MATERIAL SPEC. |
|---|---|---|---|---|---|
| A. | MANDREL, LUBRICATOR VALVE | 100019623 | 6CA01656-1-3 | ENS, AISI 4130/4140 | SH355317 |
| B. | RING, STOP, OPERATOR - LUBRICATOR VALVE | 100050586 | 6CA01567-3-1 | 17-4PH (UNS S17400 or AISI 630),H Double 1150, 105 KSI Min Yield Strength | 100160002 |
| C. | OPERATOR, LUBRICATOR VALVE | 100050589 | 6CA00737-1 | 17-4PH (UNS S17400 or AISI 630),H Double 1150, 105 KSI Min Yield Strength | 100160002 |
| D. | BALL, VALVE, CLOSED, 7.38 BORE | 100067000 | 6CA01708-1-5 | 718 (UNS NO7718) Annealed & Aged, 120 KSI Min Yield | 100237403 |
| E. | RETAINER, SEAL, BALL VALVE | 100121727 | 6CA01119-5-2 | CMS-Z1KGK.0, 925, 110 KSI MIN YS, 30-38 HRC | CMS-Z1KGK.0 |
| | MATCH DRILL S7LV | | | CMS-Z28GN.0, 2-1/4 | |

**Figure 3-6: Summary Listing**

Should any of the critical components or parts listed be replaced during the life of the tool or equipment, then the certification documentation of the new item should be added to the Quality file, along with a written record of when it was replaced, and by whom, and reference made to the number of the RITE Work Order under which the replacement was performed.

The details to be entered on the RITE Work Order are described in section 3.7.9: RITE Equipment Record of this document within the paragraphs being added POM section 2.5: Asset Maintenance - RITE.

## 3.7.7 Quality File and Initial Certification

All manufactured Well Barrier Elements must be accompanied by a Quality file in accordance with POM section 1.10.1: Quality File.

Additionally, the Quality file will contain the items which are applicable from the listing given in POM Section .

The Quality file of any Subsea equipment which is designated as a Well Barrier Element must also meet the requirements of POM sections 5.9.1: Quality File and 5.9.2: Certification by Manufacturer and Certification Agencies.

The Quality file of any Downhole Tools which are designated as a Well Barrier Elements must also meet the requirements of POM section 6.7.1: Asset Quality File.

## 3.7.8 Traceability

All manufactured Well Barrier Elements must have component traceability as described in POM section 1.10.3: Traceability.

Listings of critical parts requiring traceability are available in InTouch contents:

- For Flowheads, InTouch content ID 5684476.
- For SubSea Landing Strings, InTouch content ID: 5452895.
- For DST tools, InTouch content ID: 5684641.

For each critical part listed the date when serialization or batch numbering started, and therefore traceability began, is given.

### 3.7.9 RITE Equipment Record

Manufactured Well Barrier Elements will have a RITE Equipment record, created by the product centre responsible for its manufacture, as described in POM section 2.4.4: Reception Control. Manufactured Well Barrier Elements will also undergo a reception control as detailed in that section.

Equipment which is designated as being a Well Barrier Element has a check mark in the relevant box on the RITE Equipment Card.


**Figure 3-7: Well Barrier Elements**

### 3.7.10 Job Exposure Tracking

All tools and equipment designated as Well Barrier Elements must have a complete job exposure history recorded by means of RITE Service Reports, as specified in POM section 2.5.2: RITE Service Report (Utilization Records) (Utilisation Records).

### 3.7.11 Well Barrier Element Maintenance Requirements

The Maintenance requirements for tools or equipment designated as being Well Barrier Elements are set out in the appropriate Operations and Maintenance Manuals, and all tools and equipment must follow the RITE methodology set out in POM section 2.5: Asset Maintenance - RITE and The Testing services maintenance standard is at InTouch Content ID 4742288.

## 3.8 Training Curriculum

All Testing Services personnel working directly or indirectly on wells, or with well Barrier elements, shall ensure that they complete the QUEST SLB-QHSE-S022 (Well Integrity) level 1 training.

Testing Services personnel who are involved with the design or supervision of jobs where Well Barrier Elements are utilized are required to complete Well Integrity Level 2 training.

Further requirements for Training, knowledge, and competency are set out in POM section 9: Testing Services Personnel Qualification and Administration.

## 3.9 Acceptance Criteria Data Sheets (WBEAC)

Schlumberger produced Well Barrier Elements are assigned to various Segments which have been nominated as the element “Owner”, and who are responsible for preparation and maintenance of the individual elements as well as for the creation and maintenance of the WBEAC Data sheets.

The tabulated listing below differentiates between:

1. Well Barrier Elements for which Testing Services are responsible, and
2. Well Barrier Elements which are the responsibility of other Segments, but which Testing Services personnel should know well.

Responsible for Compliance” means that a Testing Services employee is responsible for provision or installation of the defined Well Barrier Element. This implies that the person responsible needs to have a good understanding of specifying, verifying and use/activation of the element, as well as a good understanding of the components failure modes.

Knowledge required” means that the Well Barrier Element is used by, or could be activated during operation to affect Testing Services activity. This implies that the possible failure modes of the element should be known.

Table bellow gives a listing of Well Barrier Elements and the Responsibility or Knowledge requirements and links to the appropriate Acceptance Criteria documents.

| Well Barriers Description | Owner | Testing Services Responsibility or Knowledge | Link to WBEAC Data Sheets |
|---|---|---|---|
| Fluid Column | MI | Knowledge Required | TBD |
| Lower Riser Package/Emergency disconnect | IPM | Knowledge Required (*) | IPM WBEAC's |
| Drilling BOP | IPM | Knowledge Required | |
| Stab in safety valve/Drill string safety valve | IPM | Knowledge Required | |
| Suspension packers (Storm/Hurricane packer) | Cementing | Knowledge Required | TBD |
| Wellhead | IPM | Knowledge Required | IPM WBEAC's |
| Casing | IPM | Knowledge Required | |
| Liner Top Packer | IPM | Knowledge Required | |
| Tie-back packer | IPM | Knowledge Required | |
| Cement Plug Cementing | Cementing | Knowledge Required (*) | TBD |
| Shoe track Cementing | Cementing | Knowledge Required (*) | TBD |
| Surface Production Tree IPM | IPM | Knowledge Required (*) | IPM WBEAC's |
| Deep Set Tubing Plug Completion | Completion | Knowledge Required (*) | TBD |
| Mechanical Tubular Plugs Cementing | Cementing | Knowledge Required(*) | TBD |
| Surface Test Tree/Surface testing flowhead | Testing Services | Responsible for Compliance | InTouch Content ID 5386661 "Well Barrier Element Acceptance Criteria (WBEAC) Data Sheet for Surface Test Tree" |
| Tubular Crossover | Testing Services | Responsible for Compliance | Crossover |
| Surface controlled subsurface safety valve EZV | Testing Services | Responsible for Compliance | EZV |
| Subsea Lubricator Valve for Well Testing | Testing Services | Responsible for Compliance | InTouch Content ID 5389481 "Well Barrier Element Acceptance Criteria (WBEAC) Data Sheet for LUBV-CC" |
| SenTREE 3, EZTM | Testing Services | Responsible for Compliance | SenTREE3, EZTM |
| SenTREE 3, EZTM + RETV | Testing Services | Responsible for Compliance | SenTREE3, EZTM +RETV |

| | | | |
|---|---|---|---|
| SenTREE HP | Testing Services | Responsible for Compliance | SenTREE HP |
| SenTREE 7 | Testing Services | Responsible for Compliance | SenTREE7 |
| Well Test String | IPM | Responsible for Compliance | IPM WBEAC's |
| Downhole slip joints | Testing Services | Responsible for Compliance | Slip Joint |
| Downhole circulating valve - Single shot | Testing Services | Responsible for Compliance | SHRV |
| Downhole circulating valve - Multi cycle | Testing Services | Responsible for Compliance | MCCV |
| Downhole tubing test valve - single shot | Testing Services | Responsible for Compliance | TFTV/PTV |
| Downhole Test Valve, multi cycle | Testing Services | Responsible for Compliance | PCT InTouch Content ID 5379427 "Well Barrier Element Acceptance Criteria (WBEAC) Data Sheet for PCT |
| Downhole safety valve - Single shot | Testing Services | Responsible for Compliance | SBSV/PFSU |
| Downhole carrier, gauge or sampler | Testing Services | Responsible for Compliance | DGA/RCAR / SCAR |
| Downhole jar | Testing Services | Responsible for Compliance | JAR |
| Downhole safety joint | Testing Services | Responsible for Compliance | SJB |
| Well Test Packer | Testing Services | Responsible for Compliance | PIPK/PSPK/FLXP HPPK |
| CIRP | Testing Services | Responsible for Compliance | InTouch Content ID 5669126 "Well Barrier Element Acceptance Criteria (WBEAC) Data Sheet for CIRP deployment surface equipment" |
| Gate Valves | Testing Services | Responsible for Compliance | WBEAC |
| Slickline stackable guns | Testing Services | Responsible for Compliance | WBEAC |
| POUV/ FLUP | Testing Services | Responsible for Compliance | WBEAC |

| | | | |
|---|---|---|---|
| Packoff | Wireline | Knowledge Required (**) | WBEAC In Touch Content ID 5402617, (Well Barrier Acceptance Criteria (WBEAC) Data Sheet for Wireline Pressure Containing Equipment). |
| Shear / Seal Rams | Wireline | Knowledge Required (**) | WBEAC In Touch Content ID 5402617, (Well Barrier Acceptance Criteria (WBEAC) Data Sheet for Wireline Pressure Containing Equipment). |
| Wireline BOP | Wireline | Knowledge Required (**) | WBEAC In Touch Content ID 5402617, (Well Barrier Acceptance Criteria (WBEAC) Data Sheet for Wireline Pressure Containing Equipment). |
| Wireline Lubricator | Wireline | Knowledge Required (**) | WBEAC In Touch Content ID 5402617, (Well Barrier Acceptance Criteria (WBEAC) Data Sheet for Wireline Pressure Containing Equipment). |
| Wireline stuffing box/grease inject i on head | Wireline | Knowledge Required (**) | WBEAC In Touch Content ID 5402617, (Well Barrier Acceptance Criteria (WBEAC) Data Sheet for Wireline Pressure Containing Equipment). |

(*) when relevant equipment being used.

(**) sometimes run as a responsibility service.

## 3.10 Section 3 Revision History

For more details see Appendix F.

---

**Warning**

Potential Severity: Serious
Potential Loss: Security
Hazard Category: Human

The controlled source document of this manual is stored in the InTouch Content ID 3045666. Any paper version of this standard is uncontrolled and should be compared with the source document at time of use to ensure it is up to date.

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# Surface Equipment

# 4 Surface Equipment

This section covers the use of all Surface Testing Equipment, containing and controlling pressure and flow (from flowhead or wellhead to burner or flare). Surface equipment belongs to Category 1.2 (high-pressure section, from the flowhead to the choke manifold or heat exchanger choke) or Category 2.1 (low-pressure section from the choke manifold or heat exchanger choke to the burner).

## 4.1 Overview

All surface pressure-bearing or pressure-containing equipment used by Testing Services shall be pressure rated. The rating is expressed as a Working Pressure (WP) and a Test Pressure (TP).

Testing Services can assign a lower rating than the manufacturer to meet more stringent requirements. In all cases, the Testing Services-assigned Working Pressure rating (WP) must be used.

It is forbidden to submit any piece of surface testing equipment to a pressure higher than its WP rating during operations.

The Working Pressure rating is valid for a given temperature range. If the temperature is outside of the equipment specifications, the WP rating will be reduced. In an assembly of different components, the WP of the weakest component at the operating temperature gives the overall Working Pressure rating of the system.

### 4.1.1 Test Pressure

Test Pressure for surface equipment is usually as follows:

**Table 4-1: Test Pressure for Surface Testing Equipment**

| Working Pressure (psi) | Multiplier | Test Pressure (psi) | Remarks |
|---|---|---|---|
| 20,000 | x 1.5 | 30,000 | Manifolds/Spools/Valve bodies as per API 6A spec. |
| 15,000 | x 1.5 | 22,500 | Manifolds/Spools/Valve bodies as per API 6A spec. |
| 10,000 | x 1.5 | 15,000 | Manifolds/Spools/Valve bodies as per API 6A spec. |

| Working Pressure (psi) | Multiplier | Test Pressure (psi) | Remarks |
|---|---|---|---|
| 5000 | x 1.5 | 7500 | Manifolds/Spools/Valve bodies as per API 6A spec.[1] |
| Various | x 1.5 | | Piping as per ASME B31.3 spec. |
| Various | x 1.5 | | Steam exchanger and heater coils as per API 12k |
| Various | x 1.5 | | Large vessels: separators, heat exchanger, tanks as per ASME |
| All ranges | x 1.0 | | Valve seat test |

[1] API 6A/ISO 10423 was updated to the 19th Edition effective February 1, 2005. Within this 19th Edition the Test Pressure for 5000 psi Working Pressure equipment was reduced from 2 times to 1.5 times the Working Pressure.

**Warning**
Potential Severity: Serious
Potential Loss: Assets, Personnel, Process
Hazard Category: Pressure

Do not exceed the manufacturers Test Pressure rating of any component(s) of any surface equipment assemblies. In the 19th edition of API 6A, Specification for Wellhead and Christmas Tree Equipment, the ratio of TP to WP was reduced from 2 to 1.5 and it must be considered that some legacy documentation may not reflect this reduction of Test Pressure for 5000 psi Working Pressure equipment

*eg* **Example**

If a valve body is replaced on an existing 5000 psi WP choke manifold, the valve body may have a Test Pressure rating of only 1.5 times the WP or 7500 psi while the other legacy sub-components of the choke manifold may have a manufacturer’s TP rating of 2 times the WP or 10,000 psi. In cases like this, the new Test Pressure rating of the choke manifold assembly shall not exceed any sub-component manufacturer’s Test Pressure rating and must be reduced to 1.5 times the Working Pressure, in this example - 7500 psi.

## 4.1.2 Service Category

The Service Categories (as defined in Section 1.7: Categories of Pressure-Containing Equipment) can be defined by the following parameters for Surface Well Testing Equipment.

### 4.1.2.1 Surface Well Testing Equipment

**Table 4-2: Minimum Design Temperature**

| | | |
|---|---|---|
| Standard Temperature: | 32°F [0°C]<br>-20°F [-29°C] | Category 2.1<br>Category 1.2 |
| Low Temperature: | -4°F [-20°C] | Category 2.1 |
| Arctic Conditions: | < -4°F [< -20°C] | To be fit for purpose, refer to section 4.6.3 (ASME, API, ASTM). |

**Note**
The cooling effect of gas expansion at chokes and restrictions must be taken into consideration when determining the Minimum Design Temperatures of the equipment.

**Table 4-3: Maximum Operating Temperature**

| | | |
|---|---|---|
| Defined for each equipment | | |
| Category 1.2 | Standard Temperature Service | = 250°F [120°C] |
| | High Temperature Service | = 350°F [175°C] |
| Category 2.1 | Standard Temperature Service | = 212°F [100°C] |
| | High Temperature Service | = 300°F [approximately 150°C] |

**Table 4-4: Service Types**

| | |
|---|---|
| Standard Service | Category 1.2, Category 2.1 |
| $H_2S$ Service | Category 1.2, Category 2.1 |
| Hostile Service ($H_2S$ Service + high temperature/pressure) | Category 1.2, Category 2.1 |

See Section 4.2.2: General Testing Services Specifications for additional guidelines.

**PSL:** Product Specification Level for API 6A\ISO 10423 components. See Section 4.2.2: General Testing Services Specifications for additional guidelines.

## 4.2 Standards and Specifications

The following general standards and Testing Services specifications apply to all Surface Equipment. Local authorities may issue additional regulations, which relate to well testing operations, such as:

- Det Norske Veritas rules for mobile offshore units: Offshore Standard DNV-OS-E101, Drilling Plant.
- UK Statutory Instruments SI 913 "Design and Construction Regulations" (Replace SI 289) and HSE Guidance Notes.
- NPD regulations for drilling, etc., for petroleum in Norwegian internal waters.

## *4.2.1* General Standards

Surface Equipment used by Schlumberger shall comply with the following standards:

- API Specification 6A for Flowheads, Surface Safety Valves, Choke Manifolds upstream heat exchangers chokes. The API 6A introduced the introduced the “Product Specification Level” (PSL) concept with the publication of API 6A, $15^{th}$ Edition, effective April 1, 1986. The PSL system applies a tiered level of material qualification testing and non-destructive testing to equipment as specified by the user/buyer and allows reference to standard procedures to apply continuously higher standards for higher risk equipment applications. PSL’s have number designations, as PSL 1, PSL 2, PSL 3, PSL 3G, and PSL 4, representing a progression from lowest risk to highest risk applications,
- ASME B31.3 and API 6A (design), API RP 14E (installation) for “high pressure” flowlines upstream of heat exchangers chokes,
- API RP 14E and/or ASME B31.3 for “low pressure” flowlines downstream of heat exchangers,
- API Specification 12K for Heaters and Steam Exchangers,
- API RP 14C for Surface Safety Systems,
- API Specification 14A and 14D for Surface Safety Shutdown Valves and ESD systems,
- API 16A Specification for Drill Through Equipment (Includes API Hubs),
- ASME Boiler and Pressure Vessel Code Section VIII Division 1 for Pressure Vessels,
- NACE MR-0175 for all $H_2S$ Service Equipment,
- API RP 520 and API RP 521 Pressure Relief Systems.

## *4.2.2* General Testing Services Specifications

Equipment supplied by Testing Services Technology Centers conforms to the following general specifications:

Minimum specifications shall be as follows:

**1.** Standard Service:
- API 6A Product Specification Levels: PSL1 up to 5000 psi, PSL2 up to 10,000 psi.
- Design temperature: -20 degF to 250 degF, API 6A\ISO 10423 temperature Class P + U.
- API 6A Material Class AA.

**2.** $H_2S$ Service:
- NACE MR0175.
- Design temperature: -20 degF to 250 degF, API 6A\ISO 10423 temperature Class P + U.
- API 6A Product Specification Levels: PSL2 for 5000 psi WP, PSL3/3G* to PSL4 for 10,000 psi WP and PSL3/3G* to PSL4 for 15,000 psi WP.
- API 6A Material Class DD.

**3.** Hostile Service: ($H_2S$ Service + high temperature/high pressure):
- NACE MR0175.
- Design temperature: -20 degF to 350 degF, API 6A\ISO 10423 temperature Class P + X.
- API 6A Product Specification Levels: PSL2 for 5000 psi WP, PSL3/3G for 10,000 and 15,000 psi WP and PSL4 for 20,000 psi WP.
- API 6A Material Class DD.

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**Note**

Although PSL-3 has proved, by means of an extensive track record, to be sufficient for Testing Services operations, it has been decided to move to PSL-3G for newly manufactured Flowheads as they are designated as being a Well Barrier Element (Refer to POM Section 3: Well Integrity for the detailed explanation of the term "Well Barrier Element" and related requirements, however the only Surface Testing equipment which is classed as a Well Barrier Element is the Flowhead).

Certification of Testing Pressure Equipment to PSL 3G requires at the time of manufacture a pressure test to WP with inert gas. Should the location requires to maintain PSL-3G level at Major re-certification, this test will have to be performed again (this is not a customer requirement for most of the Testing Operations).

Testing Pressure Equipment built following API 6A specification PSL-3 may be upgraded to PSL-3G under specific conditions as detailed on the InTouch Content ID 6262090 "Frequently Asked Questions on API Spec 6A - PSL-3G".

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**Note**

As defined in NACE, conformity to NACE Material Requirements applies to all components of equipment exposed to sour environments.

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Equipment sold to Schlumberger locations operating within the European Community shall comply with the latest directives providing for CE marking and be in compliance with ATEX latest directive whenever required.

Pressure Vessels for use in the USA will be manufactured in accordance with the requirements of the ASME Boiler and Pressure Vessel Codes by a manufacturer who is authorised by ASME to provide a U-Stamp.

## 4.2.3 Client Specific Standards

In addition to Government or local legislation and Industry wide or Testing Services Standards and Guidelines, there may also be client specific requirements which are applicable to any particular job.

There is an InTouch Content ID 4998375 Reference page "Worldwide Client Specific Guidelines and Standards" where these client specific requirements may be referenced.

## 4.2.4 Job Design and Well Integrity

Maintaining the integrity of a well is paramount in delivering a safe, high quality, service to our clients. In addition to following all the measures required to maintain the integrity of individual tools (such as maintenance, certification and traceability of critical parts), at the wellsite the overall Well Barrier Envelope must be established and maintained, and in order to do this all surface testing jobs must be designed and planned in accordance with POM section 3.2: Job Design, and Planning Well Barriers. The roles and responsibilities of each member of the crew must also be assigned, and this must take into consideration their levels of training and competence.

# 4.3 Surface Testing Equipment General Rules

## 4.3.1 Equipment Pressure Rating

All surface pressure and flow control equipment used upstream of and up to the choke manifold must have a minimum WP rating of 5000 psi. New equipment upstream of and up to the choke manifold shall be 5000, 10,000, 15,000 or 20,000 psi.

# 4.4 Surface Testing Equipment Configuration

Each section of the testing equipment between pressure reducing elements shall be assigned a wellsite Working Pressure rating, equal to the Working Pressure rating of the weakest component. Sections not rated to withstand the full maximum Wellhead Pressure shall be protected by a pressure-relieving device. All components used shall have a valid annual survey. Equipment lacking a current test record shall not be used.

## 4.4.1 Surface Pressure Barriers

This definition of the term “pressure barrier” must not be mixed or confused with other definitions used by customers or other Schlumberger Business segments. Nor must it be confused with the terms "Well Barrier" or "Well Barrier Element" which are defined in POM section 3: Well Integrity. The term pressure “barrier” does not mean that it must be in effect at all times. It must however be operational, installed in the initial equipment rig-up, pressure tested in the direction of flow, and ready to be activated at any time (eg SSV).

When not required for access, pressure caps such as on the flowhead or choke box must be in place and made up.

A minimum of two primary pressure barriers shall be used in the flow path. Surface pressure barriers are defined as the wellhead valves controlling the well flow. They include the master valve, flowline valve and surface safety valve. The recommended setup of a test string should be according to Table 4-5: Number of Valves versus Well Parameters.

The surface safety valve (SSV) shall be a normally closed (NC) valve located on the flowline. It should be part of the wellhead (X-mas tree) or located as close to the wellhead as possible. The valve should be connected to an Emergency Shut-Down (ESD) system, actuated by pressure sensors installed on each flowline section with different Working Pressure as well as manual push buttons.

Above 12,000 psi potential wellhead pressure (MPWHP), a production string with a production packer is recommended. Above 15,000 psi, a flanged-up X-tree shall be used.

If performing a surface shut in, it is recommended that the downstream choke valves be closed as well as the upstream ones, and the pressure between the two monitored to verify the integrity of the upstream valves. However, this assumes that the downstream valves have the same pressure rating as the upstream valves.

On HP/HT jobs it is mandatory that all pressure monitoring, sample and injection points are fitted with double isolation. This is also strongly recommended for all other jobs.

### 4.4.2 Type of Valves for Category 1 Equipment

Sliding Gate valves shall be exclusively used for all primary surface pressure barrier applications above 5000 psi or when $H_2S$ is present.

Plug valves are tolerated for Standard Service applications below 5000 psi wellhead pressure and when a downhole DST valve is present. Hydraulically actuated safety valves, with a ball valve sealing mechanism, can be used above 5000 psi when backed up by at least one gate valve.

Above 12,000-psi potential wellhead pressure (MPWHP), a production string with a production packer is recommended. Above 15,000 psi, a flanged-up X-tree shall be used.

**Table 4-5: Number of Valves versus Well Parameters**

<table>
<tr><th rowspan="2">Flowrate and/or Shut-in Wellhead Pressure (psi)</th><th colspan="4">Nature of Fluid</th></tr>
<tr><th>Oil</th><th>Gas</th><th>Oil $H_2S$</th><th>Gas $H_2S$</th></tr>
<tr><td rowspan="3">High Flow Rate Gas ≥ 30 MMSCF/D<br>Liquid ≥ 8000 bpd</td><td>$S_2$ + ESD</td><td colspan="3">$S_3$ + ESD</td></tr>
<tr><td>$SS_1$</td><td colspan="3">$SS_1$</td></tr>
<tr><td>$D_1$</td><td colspan="3">$D_2$</td></tr>
<tr><td rowspan="3">< 3000</td><td colspan="2">$S_2$</td><td colspan="2">$S_2$ + ESD</td></tr>
<tr><td colspan="2">$SS_0$</td><td colspan="2">$SS_0$</td></tr>
<tr><td colspan="2">$D_1$</td><td colspan="2">$D_2$</td></tr>
<tr><td rowspan="3">3000 < < 5000</td><td colspan="2">$S_2$</td><td colspan="2">$S_2$ + ESD</td></tr>
<tr><td colspan="2">$SS_0$</td><td colspan="2">$SS_1$</td></tr>
<tr><td colspan="2">$D_1$</td><td colspan="2">$D_2$</td></tr>
<tr><td rowspan="3">5000 < < 10,000</td><td>$S_2$ + ESD</td><td colspan="3">$S_3$ + ESD</td></tr>
<tr><td>$SS_1$</td><td colspan="3">$SS_1$</td></tr>
<tr><td>$D_1$</td><td colspan="3">$D_2$</td></tr>
<tr><td rowspan="3">10,000 < < 15,000</td><td colspan="4">$S_3$ + ESD</td></tr>
<tr><td colspan="4">$SS_1$</td></tr>
<tr><td colspan="4">$D_2$</td></tr>
<tr><td rowspan="4">> 15,000</td><td colspan="4">Production String Mandatory</td></tr>
<tr><td colspan="4">$S_3$ + ESD</td></tr>
<tr><td colspan="4">SCSSV</td></tr>
<tr><td colspan="4">$D_0$</td></tr>
<tr><td rowspan="9">Legend</td><td colspan="4">$S_2$= Master Valve + Flowline Valve</td></tr>
<tr><td colspan="4">$S_3$ = Master Valve + Flowline Valve + Surface Safety Valve (SSV)</td></tr>
<tr><td colspan="4">$SS_o$= Subsurface Valve (EZ valve, SCSSV, etc..) not mandatory (except for floating rigs where a SubSurface Test Tree is needed).</td></tr>
<tr><td colspan="4">$SS_1$ = E-Z Valve or Subsea Tree or SCSSV</td></tr>
<tr><td colspan="4">$D_1$ = DST Valve</td></tr>
<tr><td colspan="4">$D_2$ * = DST Valve + DST Safety Valve</td></tr>
<tr><td colspan="4">$D_0$ = Downhole Valve not mandatory with production string</td></tr>
<tr><td colspan="4">High Flow Rate = flow rate ≥ 30 MMSCF/D gas and/or ≥ 8000 bpd liquid</td></tr>
<tr><td colspan="4">The above valve configurations are understood as a minimum recommended setup and may be upgraded at customer's discretion.</td></tr>
</table>

* Exception to this recommendation is acceptable for:

1. Ultra HPHT operations using the "J" string, due to the single shot nature of these tools. There is a high reliability of single shot tools and the importance of keeping the string as simple as possible justifies this exception.
2. Large Bore strings where a large bore DST safety valve does not exist. In this case an E-Z Valve or Subsea Tree or SCSSV is strongly recommended for all wells where it is not already mandatory in the above table and a HARC must be developed to mitigate any safety concerns.
3. If WHP < 3,000 psi and there is an E-Z Valve or Subsea Tree or SCSSV in the string, then the requirement is relaxed to D1 only.

The Subsea Tree, E-Z Valve and SCSSV are safety valves and shall not be used as lubricator valves.

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**Note**

The advantage of the HiPAck (HPPK) is that it is single trip set and release alternative to permanent packers. A key feature of the HiPAck is the Below Packer Circulating Valve (BPCV), however this is not compatible with a DST safety valve such as a PFSV as it will be impossible to reverse through the BPCV once the PFSV is activated.

If the BPCV function is not going to be used, then the HPPK should be run with a blank BPCV sub.

However, if the job design requires the use of the BPCV feature, and the well conditions require the use of a DST safety valve (ie D2 in the table above), then a HARC shall be performed and an exemption raised in QUEST following the process in SLB-QHSE Standard #10 with approval at Area level for the removal of the safety valve from the string.

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## 4.4.3 Flowhead or Production Tree

All well test configurations should have separate kill line and flowline connections to the wellhead, downstream of the master valve.

The Flowhead is the only item of Surface Testing equipment which is considered to be a Well Barrier Element. (Refer to POM Section 3 for the detailed explanation of the term "Well Barrier Element" and related requirements).
5 kpsi WP $H_2S$ service Flowheads which are in the field have been certified to a minimum of API 6A / ISO 10423:2009 (Modified) Production Service Level (PSL) 2, and $H_2S$ service Flowheads with a WP of 10 K and above have been certified to a minimum of PSL-3.

Starting in 2012, $H_2S$ service Flowheads with a WP of 10 kpsi or above will be certified at the time of manufacture to PSL-3G. The 3G is a recently introduced API 6A / ISO 10423:2009 (Modified) PSL. Although PSL-3 has proved, by means of an extensive track record, to be sufficient for Testing Services operations, it has been decided to move to the higher specification PSL-3G for certain items of equipment which will be used as a Well Barrier Element.

Certification to PSL-3G requires an additional pressure test with gas to WP at the time of manufacture to further prove the tolerances and fit of the assembled item, over and above the hydrostatic test to TP, on the basis that gas may find a means of escape which the hydrostatic fluid will not. Testing with gas in locations is not required in order to maintain the PSL-3G certification provided that only Product Centre supplied Original Equipment Manufacturer (OEM) replacement parts have been used for maintenance or repair.

### *4.4.3.1* Flow Line

The flowline valve is usually operated by hydraulic actuator allowing remote or automatic closure and connection to an Emergency Shutdown System (ESD).

### *4.4.3.2* Kill Line

It is mandatory to use a check valve between the Kill Line hose or piping and the Flowhead or Production Tree on all operations. All location have until the 01st January 2014 to procure the check valves through the Product Center, in the meantime all operations done without check valve shall be supported by a HARC. The check valve must be mounted as close as possible to the Flowhead or Production tree. Due to reliability issue, lock open type check valve shall not be used unless specifically required by the customer in which case an exemption will be required.

### *4.4.3.3* Swivel

When the flowhead includes a swivel, or if some other device including a swivel is used between the string and the flowline, the swivel must be located downstream of the master valve unless dual lubricator valves are included in the string, and the distance between the top lubricator valve and the swivel is a maximum of 100 ft.

**Danger**
Potential Severity: Catastrophic
Potential Loss: Assets, Personnel
Hazard Category: Explosives, Fire flammable, Pressure

If running any guns or tools through the flowhead or production tree via Wireline or Coiled Tubing, especially when the flowhead block has a 45 deg angle between the production bore and the flow and kill lines, the following steps must be taken.

1. Performing intervention runs through the flowhead must be included in the job specific HARC.
2. If intervention was not initially planned, a Management of Change (MOC) must be created and approved in Quest.
3. The flowhead or production tree flow and kill line valves must be closed before any tool passes through the flowhead. (They may be opened again once the toolstring is safely below the rotary table).
4. Ensure that the Wireline Engineer or Well Services Supervisor for the job are aware about the possibility of the guns/tools going down the flowline or kill line if specific conditions exist.
5. The Testing Services Supervisor or Crew Leader must be involved when any tool is run through the Flowhead.

## 4.4.4 Emergency Shutdown System

For high flow rates (Gas > 30 MMSCF/D, or Liquid > 8000 bpd), or when the maximum possible wellhead pressure exceeds 5000 psi, or at any time $H_2S$ is present, an emergency shutdown system (ESD) shall be used. It is also recommended to use a basic ESD on all other well test operations.

The ESD system (pneumatic or electric) consists of a remotely actuated valve on the flowhead or a stand-alone remotely actuated isolation valve on the wellhead. At any time an ESD is used, a minimum of two remote control stations shall be set up; one at the separator and one in an area away from all equipment containing well pressure and flow. ESD shall be function-tested before the start of each job and the shut-in time confirmed.

The following guidelines are recommended for HPHT/HQ applications:

1. Basic 3-stage architecture of the safety systems with:
   a. Well parameters (pressure, temperature, flow rate, $H_2S$ content, etc.) monitored continuously with redundant electronic and manual systems; measured parameters compared with the “operating envelope” parameters defined for the well test design.

b. Emergency shutdown systems controlling wellhead valve, subsea safety valve and flowline valve, activated by manual control, Lo/Hi pressure pilots or fusible loops and temperature sensors.

The above measures provide safety redundancy at any stage with sufficient segregation of operations to prevent system failure due to any component breakdown.

2. Total protection at surface:
   a. On a semi-submersible rig, incorporate the Subsea-Tree (SenTREE) into the ESD system.
   b. On a jack-up or land rig, run an E-Z Valve linked to the ESD.
   c. Wellhead valve closure and shutdown of test equipment if well parameters exceed the operating envelope, the pilots are actuated or surface equipment essential to well control fails creating a safety or environmental hazard; closure at Subsea safety valve in case of catastrophic failure.
   d. Bypass of the automatic ESD controls in a) and b) whenever wireline or coil tubing is in the well; only manual actuation allowed.
   e. Operating time of the safety system shall be less than 10 sec to full closure of the surface safety valves when operated manually or by the slowest pilot device. In order to achieve closure in this time frame it may be required to add air and/or hydraulic quick exhaust (dump) devices to the ESD control systems.

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**Note**

The above guidelines are only a summary and not all points may apply in all situations. The relevant technical documentation must be consulted, and after a HARC has been carried out, a specific detailed design for the ESD system should be produced for each high pressure/high temperature/high flowrate job.

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## 4.4.5 Flexible Test Lines

Coflexip or similar hoses shall be chosen in accordance to temperature, pressure and fluid type expected. Refer to manufacturers specifications for examples of commonly used hoses. See Table 4-6: COFLEXIP/Coflon and Black Eagle Data.

Black Eagle hoses are not certified for upstream applications and are therefore not allowed between the Flowhead or Wellhead and the choke manifold. They are to be used for kill line applications or downstream of the choke manifold only.

Non $H_2S$ Hoses (such as Black Eagle) shall not be purchased or transferred to any location with $H_2S$. All Non $H_2S$ flexible must be clearly identified by a visible metallic band stating “STANDARD SERVICE ONLY / NON $H_2S$”. See Table 4-6: COFLEXIP/Coflon and Black Eagle Data.

Maximum working temperature versus exposure time limits and minimum bending radius specifications must be respected. Hoses exposed to temperature above normal continuous rating shall be removed from service upon completion of work in progress.

Accurate records of $CO_2$, $H_2S$, Acid, pressure and especially temperature exposure versus time must be maintained and recorded in RITE in service reports, and hoses retired from service according to manufacturer’s recommendations. Prior to a major survey being carried out the Job history records must be reviewed to ensure that the recertification is justified based on the exposure history of the hose as well as its physical condition and recommended service life. The likely future job exposure should also be taken into consideration.

Hoses without exposure histories for all jobs performed become subject to the following conditions:

- For the hose to be retained in service, a documented assessment of past exposure to erosive or corrosive substances (including $H_2S$), high flow rates, or high pressures and temperatures must be made. The assessment, along with the COC of the hose (which will give the date of manufacture) must then be attached to a QUEST exemption for continued use of the hose with approvals at both Area and Segment level. If the hose is kept in service a printed copy of the assessment and the approved exemption must be filed in the hose Quality File. Rejection of the exemption request means that the hose must be junked.
- They must not be transferred or loaned between locations.
- They must not be used for HP/HT or High flowrate jobs.
- Prior to each Q-Check (Annual Survey) the RITE history card of the hose, updated with the jobs performed since the previous Q-Check, along with the original assessment of previous exposure and the COC, must be attached to a QUEST exemption requesting further use of the hose. The exemption must be approved at Area level.

Testing Services strongly recommends that Coflexip hoses be procured with API or Grayloc hub connections, as these do not have the same angular rotation restrictions which bolted API flanges have.

Further information on maintenance and handling of Coflexip hoses can be found in and in the Coflexip operations and maintenance manuals.

**Table 4-6: COFLEXIP/Coflon and Black Eagle Data**

| Item | Standard (non $H_2S$) Black Eagle | Standard | High Temperature | High Temperature | High Temperature |
|---|---|---|---|---|---|
| Lining | Polyamide (PA11) | Rilsan | PVDF Coflon | PVDF Coflon | PVDF Coflon |
| Applications | Non $H_2S$ | DST, extended Test (PTL) | DST, Extended test (PTL) | DST, Extended test (PTL) | DST, Extended test (PTL) |
| Nominal size | 2-in. bore 45 or 60 ft | 2-in. or 3-in. bore 45 or 60 ft long | 2-in. or 3-in. bore 45, 60, or 70 ft long | 2-in. 3-in. or 4-in. bore 45, 60 or 75 ft long | 2-in. 3-in or 4-in. bore 45 or 60 ft long |
| Pressure rating | 10,000 psi WP 15,000 psi TP | 10,000 psi WP 15,000 psi TP | 5,000 psi WP 7,500 psi TP | 10,000 psi WP 15,000 psi TP | 15,000 psi WP 22,500 psi TP |
| Temperature rating | -10 degC to 70 degC, continuous | -20 degC to 100 degC, continuous | -20 degC to 130 degC, Continuous Up to 160 degC, 1 hour PTL only - Up to 145 degC, 1 month (cumul.) | -20 degC to 130 degC, continuous Up to 160 degC, 1 hour PTL only - Up to 145 degC, 1 month (cumul.) | -20 degC to 130 degC, continuous Up to 160 degC, 1 hour PTL only - Up to 145 degC, 1 month (cumul.) |
| Connections | 2-in. 1502 Hammer Union | 2-in. or 3-in. 1502 Hammer Union | 3-in. 1002 Hammer Union, 2-in or 3-in API flange | 2-in. 3-in. or 4-in. 1502 Hammer Union API Hub or Flange | Grayloc C25, API Hub or Flange |
| Limits of use | Not allowed between the Flowhead or Wellhead and the choke manifold, Non-acidified effluent only. No heavy metallic salts (Zinc, calcium bromides, etc.) at high temperature. | Non-acidified effluent only. No heavy metallic salts (Zinc, calcium bromides, etc.) | No concentrated acids at high temperature | No concentrated acids at high temperature | No concentrated acids at high temperature |

This is a generic summary table only, not all of the hoses are available with all of the alternatives as routine options.

Refer to the In Time catalogue for the current commonly available options, or contact SRPC External Sales for special requirements.

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**Note**

The use of any type of low pressure flexible hose (see Section for details), unless clearly specified by a product center, is only permitted for the transfer of dead well effluent (pump suction and transfer from tank to tank), for diesel fuel supply, or for utility supply of air, water etc.

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**Note**

Coflexip hoses with a Rilsan lining should no longer be purchased and have been removed from the In Time Catalogue. Existing Rilsan lined hoses may be used up to the end of their natural life without being changed.

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## 4.4.6 Data Header

The Data header is a short sub or pipe with threaded ports which can be used for pressure gauges or sensors, thermowells, and sampling or injection points. The data header comes in a variety of connections (hammer union, hub or flange) and is typically connected to the pipework upstream of the choke manifold.

Data headers shall be considered as being the same as piping, and undergo the maintenance requirements as set out in section , with the additional steps for an annual or major survey of magnetic particle inspection on the weld of any threadolets, and gauging of the threadolet internal threads to ensure they are fit for purpose.

## 4.4.7 Chokes and Choke Manifolds

Only one choke is used, it should be located near the wellhead. The downstream flow passage should be free of abrupt changes of diameter or direction within a distance equal to ten nominal flow passages. Adjustable testing chokes shall have integral stems with solid carbide tips. Two-piece stems/tips shall not be used.

All choke manifolds shall have upstream choke and downstream choke valves with the same pressure rating.

**Note**

in case of HPHT/HQ the adjustable choke seat should have a tungsten carbide sleeve running the complete length of the seat and not just as a ring on the face. This is to reduce the possibility of the seat being eroded by the combination of the action of the adjustable stem tip and the high flow rate.

## 4.4.8 Surface Relief Facilities

### 4.4.8.1 PRV/PSV Operation

Surface relief facilities shall generally comply with API RP 520 and API RP 521.

When selecting the in-line Pressure Safety Valve (PSV) or Pressure Relief Valve (PRV), preference should be given to spring loaded safety valve with balanced bellows if the back pressure allows. This type of valve is less sensitive to start-up transient and dirty service. However, in some cases, a Pilot Operated will have to be used.

For detailed information, please refer to the Balanced Bellow PRV operating and maintenance manual In Touch Content 6071992 and the Pilot Operated PRV operating and maintenance manual InTouch Content 5859575.

Since the PRV is a critical safety device which can be sensitive to dirt and debris, if a Pilot Operated Pressure Relief Valve has to be used, it must be fitted with the following mandatory accessories:

- Dome spring suitable for $H_2S$.
- Non-flowing, modulating pilot.
- Pilot supply filter.
- Field test connection.
- Back flow preventer.
- A shuttle valve (Backflow preventer) between the pitot tube and the pilot supply filter.

the below points should be taken into consideration during job planning and design.

1. InLine PRV's must be installed downstream of a change of the process system pressure rating, and be mounted as closely as possible after a distance equal to ten pipe diameters downstream from any equipment inducing a variation of flow cross-section. For example; to protect a line

downstream of a 3" Choke Manifold where the line has a lower WP than the Choke Manifold itself, the inLine PRV should be installed at a distance of 30 inches (1 meter) downstream of the choke manifold outlet.

**2.** InLine PRV's should always be installed in a vertically upright position as recommended in API RP 520. This means that the PRV will be mounted on the vertical branch of a pipework tee which is at right angles to the normal flow of the well fluids. Inlet piping to the pressure relief valve should be sized to minimize the pressure loss and configured to avoid accumulation of foreign matter.

**3.** InLine PRV's and its outlet need to be well supported and restrained to reduce shock to/vibration to the PRV whilst the outlet connection is being made up, and also to minimize any bending moment acting on the vertical pipe and connections below the PRV if it operates.

**4.** For Pilot Operated InLine PRV's, the Nitrogen supply circuit/bottles must be independent from any other high consumption N2 circuit to avoid running out of Nitrogen or getting unstable pressure.

**5.** For all types of PRV, the ID of the inlet piping must be at least equal to the PRV inlet flange size, and no reducers or Crossovers to smaller diameter piping than that which is on the PRV outlet is allowed.

### *4.4.8.2* PRV/PSV Calibration

As per section 4.7.2: Regular Inspection and Annual Surveys all Pressure safety valves (PSV) or Pressure relief valves (PRV) shall be inspected, maintained and recalibrated every 12 months. Maintenance and recalibration shall be carried out by an agent who is approved by the PSV manufacturer, or by a SLB person who has attended a training course run by the manufacturer. Where the approved agent carries out the calibration they shall issue a recalibration certificate. Where the recalibration was carried out by a trained SLB representative the calibration shall be witnessed and the certificate stamped and verified by a independent third party inspector.

## *4.4.9* Pipework

Technical information relating to pipework is contained in Appendix B.

The Testing Services assigned Working Pressure (WP) ratings for pipework assemblies with hammer unions, shown in Figure B-1: Standard Pressure Hammer Union Pipework Table, Figure B-2: High Pressure Hammer Union Pipework Table.

The working pressure ratings for the pipework assemblies with GRAYLOC connectors are shown in Figure B-3: Schlumberger Rating for “Grayloc” Clamp Connector Pipework.

The working pressure ratings for the pipework assemblies with ASME flange connectors are shown in Figure B-4: Low Pressure ASME Flanged Pipework Table.

It is not permitted to down-rate pipework from its original assigned Working Pressure rating.

To ensure conformance to original Working Pressure rating, a minimum wall thickness has been defined in Figure B-1: Standard Pressure Hammer Union Pipework Table, Figure B-2: High Pressure Hammer Union Pipework Table, Figure B-3: Schlumberger Rating for “Grayloc” Clamp Connector Pipework and Figure B-4: Low Pressure ASME Flanged Pipework Table for use as the rejection criteria during pipework maintenance.

For any pipework, it is of vital importance to understand that:

- The pressure rating of the hammer unions does not give the rating of the pipe assembly.
- The pressure rating of any assembled pipework system is not determined by the end connection or the pipe itself, but by the lowest rated section.
- It is forbidden to use hammer unions where the male or female sub of the union has internal threads for attachment to the pipe body for any pipework applications. NPST Connections are not allowed in Well Testing operations.

Articulated Piping with swivels are forbidden in surface testing operations except under the conditions given in Section Appendix B.2.3.9: Use of Articulated Pipework.

All pipework connections to be assembled on the wellsite shall have unions with replaceable seals, either elastomer lip-seals or metal-to-metal seal rings.

It is mandatory to use premium seal connections (metal-to-metal seals such as API Specification 6A flanges or Hub connectors, or Grayloc) for High Pressure - High operating Temperature pipework applications. (> 10 kpsi and > 250 degF) and strongly recommended for applications flowing high concentrations of $H_2S/CO_2$. This is because in high-pressure applications, especially when flowing gas, the hammer union elastomer lip seal is not capable of withstanding pressure cycling, and "explosive decompression" will occur.

**Note**

Flowback of acid can also be aggressive for well test piping elastomer lip seals if not properly chosen to resist acid and any additives that may be present. Careful seal selection is required to ensure all conditions can be met.

A tie-down or Line Securing / Restraint system must be in place prior to any surface testing operations commencing. (See section 4.4.9.3: Tie-Down or Line Securing Systems).

**Note**

When rigging up temporary pipework the effects of thermal expansion must be taken into consideration. In order to reduce stress on the piping and the connections to the equipment it may become necessary to add a loop or bridge of elbows and pipe to compensate for expansion and contraction.

If using piping sections when connecting to the flowhead or well head, be aware that thermal movement affects the tubing and /or casing and can compromise the flow line if compensation for thermal movement is not allowed for in the rig up.

It has been recorded during long duration and high flow rate jobs the well head had moved up by one meter.

Additionally, movement in the flowlines may create twisting of the pipe which in the case of Hammer Unions may cause the connections to slacken.

**Danger**

Potential Severity: Catastrophic
Potential Loss: Personnel
Hazard Category: Pressure

Tightening or slackening of connections, moving the pipework, or similar operations while the pipework contains pressure shall not be performed under any circumstances.

## 4.4.9.1 Pipework Sizing

The Pipework must be sized based on flow velocity, pressure drop, and erosive and corrosive effects as simulated in Architest.

A “surge factor” of at least 20% should be added to the anticipated maximum flow. API RP14E recommended erosion velocity limitations may be exceeded for temporary well test installations, provided pipework is inspected at frequent intervals which do not exceed 2 hours between measurements. Pipework shall be thickness checked before each job if high velocities and/or sand production are expected.

It is recommended for high flowrate jobs (greater than 30MM scf or 8000 BPD) to:

- Check critical piping thicknesses before, during and after each job. If not already performed as part of the TRIM following the previous job that the pipe performed, it must be thickness checked and the results recorded in RITE. These measurements should then be used as a reference during the job to confirm the rate of erosion. While flowing the well, the wall thickness of the pipe and equipment most vunerable to erosion must be checked at least once every two hours.
- Use targeted flanges or cushion elbows.

## 4.4.9.2 Relief Valve Discharge Piping

The discharge piping shall be designed to minimize back-pressure. The maximum back pressure allowed on the pressure relief valve under maximum flow conditions (i.e., the outlet(s) blocked in the section protected by the PSV) is dependent on the specific type (pilot or balanced bellows) and size of PSV used, so it is vitally important to know what the manufacturer recommendations are for it.

As a general guide:

- For a Pilot Operated Pressure Relief Valve, the maximum back-pressure must be at least 1 bar (14.5 psi) less than the set pressure of the valve.
- For a Balanced Bellows Pressure Relief Valve, the maximum pressure that the bellows can withstand may be as little as 13% of the set pressure for a 3" x 4" 100 bar PSV.

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**Note**
This value is substantially less than the 50% commonly quoted.

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Architest must be used to determine the size of discharge piping required, but in any case no reducers or crossovers to a smaller diameter than the PRV outlet are allowed at any point in the relief line.

Where more than one PSV discharges into a relief line, the back-pressure effect on all of the PSV's from just one of them lifting must be taken into consideration. While PSV's outlets can be Teed together, it is a good working practice to avoid teeing PSV's which protect different sections of the rig up, but which have similar set pressures (for example the PSV protecting the line between the choke and the separator, and the PSV's on the Separator itself) together, as under certain conditions they may try and relieve at the same time and the back pressure from one will affect the operation of the other, with the possibility that a harmonic interaction will also take place.

Piping must be configured to minimize the reaction forces on the pressure relief valve during discharge and be secured to avoid whipping.

## *4.4.9.3* Tie-Down or Line Securing Systems

**Pipework Restraint Systems**

A wellsite pipework restraint system is the final measure in the series of prevention and mitigation measures (such as regular inspections, and pressure testing etc.) which are in place to protect personnel, equipment, and the environment from the consequences of a failure under well or pump pressure.

If a pipe fails during a pressure test the explosive force of such a failure can cause significant damage and risk of injury, however the pressure of the fluid within the pipe is quickly dissipated at the moment of failure unless energized by entrained air or gas. If the fluids inside the pipe are energized, then they will continue to exert dynamic forces until such time that they are exhausted. If failure of a pipe occurs while flowing from a well (or pumping into one at high flow rates) then the fluids will continue to exert dynamic forces up to the point at which the reservoir can be isolated (or the pump shut down).

Studies have led to the conclusion that the dynamic force acting on pipework containing an energized fluid, should a failure occur, can be represented by the formula:

$Fd = k * d^2 * P$

Where:

Fd = The dynamic force in metric Tonnes

k = A constant, equal to 0.000516

d = The internal diameter of the pipe in inches

P = The pressure of the fluids inside the pipe in psig

Applying this formula to the Schlumberger Testing approved pipework sizes at specific pressures gives the following results:

**Note**

The columns below each pressure give the force in both metric Tonnes (mtf), and kilo lbs force (klbf).

**Table 4-7: Pipework Dynamic Loading @ Internal Pressure**

| Pipework Dynamic Loading @ Internal Pressure | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 750 psi | | 1500 psi | | 2300 psi | | 5000 psi | | 10000 psi | | 15000 psi | |
| | mtf | klbf | mtf | klbf | mtf | klbf | mtf | klbf | mtf | klbf | mtf | klbf |
| 6" 206 | 14.6 | 32.2 | 29.2 | 64.4 | | | | | | | | |
| 3" 602 | 3.7 | 8.1 | 7.4 | 16.2 | 11.3 | 24.9 | | | | | | |
| 4" 602 | 6.2 | 13.7 | 12.4 | 27.4 | 19.0 | 42.0 | | | | | | |
| 3" GR 27 | 3.7 | 8.1 | 7.4 | 16.2 | 11.3 | 24.9 | | | | | | |
| 3" 1002 | 2.8 | 6.2 | 5.7 | 12.5 | 8.7 | 19.1 | 18.9 | 41.6 | | | | |
| 4" 1002 | 4.7 | 10.3 | 9.4 | 20.6 | 14.4 | 31.7 | 31.2 | 68.8 | | | | |
| 6" 1002 | 10.1 | 22.4 | 20.3 | 44.7 | 31.1 | 68.6 | 67.6 | 149.1 | | | | |
| 3" GR 23 | 2.8 | 6.2 | 5.7 | 12.5 | 8.7 | 19.1 | 18.9 | 41.6 | | | | |
| 4" GR 34 | 4.7 | 10.3 | 9.4 | 20.6 | 14.4 | 31.7 | 31.2 | 68.8 | | | | |
| 6" GR 52 | 12.1 | 26.7 | 24.2 | 53.3 | 37.1 | 81.7 | 80.6 | 177.7 | | | | |
| 2" 1502 | 1.3 | 3.0 | 2.7 | 5.9 | 4.1 | 9.1 | 9.0 | 19.8 | 18.0 | 39.7 | | |
| 3" 1502 | 2.9 | 6.5 | 5.9 | 12.9 | 9.0 | 19.8 | 19.5 | 43.1 | 39.1 | 86.2 | | |
| 4" 1502 | 4.8 | 10.7 | 9.7 | 21.4 | 14.9 | 32.8 | 32.3 | 71.2 | 64.6 | 142.4 | | |
| 4" D 31 | 4.8 | 10.7 | 9.7 | 21.4 | 14.9 | 32.8 | 32.3 | 71.2 | 64.6 | 142.4 | | |
| 6" G 52 | 10.9 | 24.0 | 21.8 | 48.0 | 33.4 | 73.7 | 72.6 | 160.2 | 145.3 | 320.3 | | |
| 3" C 25 | 3.2 | 7.1 | 6.4 | 14.1 | 9.8 | 21.6 | 21.3 | 47.0 | 42.7 | 94.0 | 64.0 | 141.1 |
| 4" C 25 | 3.4 | 7.5 | 6.8 | 15.0 | 10.4 | 23.0 | 22.7 | 50.0 | 45.3 | 100.0 | 68.0 | 149.9 |

In addition to the forces shown in the table above, any piping restraint system should be tightened so that in the event of failure additional force is not generated by movement of the failed parts creating momentum and subsequent shock loading. Having slack in the restraint system will increase the forces shown in the table by a significant factor.

The use of Polyester Roundslings for pipework restraint systems is already required by certain clients and is strongly recommended for the others. **Their use is mandatory on all Testing Services jobs**.

They will also become mandatory for any pressure test carried out outside a pressure test bay at the same date. This does not change the existing requirements set out in Section Appendix A.8: Pressure Tests Outside a Test Bay.

A Polyester roundsling is a continuous loop of parallel polyester yarns, encased in an outer cover. (Similar to the inner tube of a tyre). Thus manufacturers generally give two different lengths for each sling – an overall, or circumferential length, and an “effective length” which is the length of the sling when stretched between two points. (ie the Effective length is half the circumferential length).

There are two different standards to which polyester Roundslings are manufactured. ASME B30.9 and EN 1492-2. Only slings which are in accordance with one of these standards may be used.

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**Note**
There is also a standard EN 1492-**1** which covers Flat woven webbing slings. These slings are **NOT suitable** for use in pipework restraint systems.)

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Roundslings are manufactured for general purpose use and in common with all lifting devices have a high factor of safety. The factor of safety is 5 for slings manufactured to ASME B30.9 and 7 for slings manufactured to EN 1492-2. When used for pipework restraint systems the factors of safety are removed and the sling can be used up to its full design strength, however an alternative allowance has to be built in to allow for strength reductions due to the additional stresses caused by hitching or knotting the sling to the pipework or to anchor points.

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**Note**
Slings which are used for pipework restraint systems must NEVER be used for lifting purposes.

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Slings manufactured to EN 1492-2 are rated in whole metric tonne capacities and are colour coded up to 10 Tonnes. (All slings of 10 Tonnes capacity or more are coloured Orange).

Slings manufactured to ASME B30.9 are rated in Lbf capacities which do not directly correspond to a whole long Ton or whole Metric Tonne figure and are identified by a Tag number. There is no colour coding scheme defined in the ASME standard, however individual manufacturers may define their own.

**Danger**

Potential Severity: Catastrophic
Potential Loss: Personnel
Hazard Category: Pressure

As roundslings manufactured to ASME B30.9 do not have a colour coding defined in the standard, it is possible that different manufacturers may apply different colour schemes to designate the rated capacities. Always use the tag number to identify the correct rated capacity of the roundsling, and be especially careful if slings manufactured to both EN 1492-2 and ASME B30.9 are available in the same location – it is recommended that locations should purchase roundslings which are in accordance with only one of the standards to avoid possible confusion.

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Where shackles are utilized to join slings together or attach the restraint system to an anchor point they must have the same or greater strength than the sling that they are attached to.

Figure 4-1: Polyester Roundsling Application Chart shows the colour code or tag number of the roundsling required for given sizes of pipework and operating pressures.

A strength reduction allowance for the use of reef knots to join or secure the roundslings has already been built into the colour codes and tag numbers shown in the table.

**Polyester Roundsling Application Chart**

| | 750 psi | | 1500 psi | | 2300 psi | | 5000 psi | | 10000 psi | | 15000 psi | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Colour (EN 1492-2) | Tag No. (ASME B30.9) | Colour (EN 1492-2) | Tag No. (ASME B30.9) | Colour (EN 1492-2) | Tag No. (ASME B30.9) | Colour (EN 1492-2) | Tag No. (ASME B30.9) | Colour (EN 1492-2) | Tag No. (ASME B30.9) | Colour (EN 1492-2) | Tag No. (ASME B30.9) |
| 6" 206 | Red | 5 | Orange 10 | 9 | | | | | | | | |
| 3" 602 | Green | 2 | Yellow | 3 | Gray | 4 | | | | | | |
| 4" 602 | Green | 3 | Gray | 5 | Brown | 6 | | | | | | |
| 3" GR 27 | Green | 2 | Yellow | 3 | Gray | 4 | | | | | | |
| 3" 1002 | Green | 2 | Green | 2 | Yellow | 3 | Brown | 6 | | | | |
| 4" 1002 | Green | 2 | Yellow | 3 | Red | 5 | Orange 10 | 9 | | | | |
| 6" 1002 | Yellow | 4 | Brown | 7 | Orange 10 | 9 | 2 x Orange 10 | 2 x 9 | | | | |
| 3" GR 23 | Green | 2 | Green | 2 | Yellow | 3 | Brown | 6 | | | | |
| 4" GR 34 | Green | 2 | Yellow | 3 | Red | 5 | Orange 10 | 9 | | | | |
| 6" GR 52 | Gray | 5 | Blue | 7 | Orange 12 | 10 | 2 x Orange 12 | 2 x 10 | | | | |
| 2" 1502 | Green | 2 | Green | 2 | Green | 2 | Yellow | 3 | Brown | 6 | | |
| 3" 1502 | Green | 2 | Green | 2 | Yellow | 3 | Brown | 7 | Orange 12 | 10 | | |
| 4" 1502 | Green | 2 | Yellow | 3 | Red | 5 | Orange 10 | 9 | 2 x Orange 10 | 2 x 9 | | |
| 4" D 31 | Green | 2 | Yellow | 3 | Red | 5 | Orange 10 | 9 | 2 x Orange 10 | 2 x 9 | | |
| 6" G 52 | Gray | 4 | Blue | 7 | Orange 10 | 9 | 2 x Orange 10 | 2 x 10 | 4 x Orange 12 | 4 x 10 | | |
| 3" C 25 | Green | 2 | Green | 3 | Yellow | 4 | Blue | 7 | 2 x Blue | 10 | 2 x Orange 10 | 2 x 9 |
| 4" C 25 | Green | 2 | Green | 3 | Yellow | 4 | Blue | 7 | 2 x Blue | 10 | 2 x Orange 10 | 2 x 9 |

The slings shown are the minimum requirement for the given pipe size and pressure.
Where the colour Orange is shown, it is followed by the metric tonne rating of the sliding concerned.
Where multiple slings are shown, it assumes an even loading between them. To obtain this, the multiple slings must be evently distributed around the pipe.
On jobs where the surface temperature of the pipe is expected to go above 194 degF (90 degC) then a roundsling which is one load rating size higher than that shown in the table must be used. (For example, if a Red roundsling is shown in the application table above, a Brown one must must be used instead).The sling strength progression for slings made to EN 1492-2 is Green / Yellow / Grey / Red / Brown / Blue / Orange. (Orange roundslings are available in several different strengths). ASME B30.9 Slings - Strength progression goes with Tag Number (2, 3, 4 etc.) where the higher the number, the higher the rated strength.
If the surface temperature of the pipework is expected to go above 250 degF (121 degC) then thermal insulation should be used between pipework and rounslings to limit potential for damaging the roundslings.
If the outside temperature is expected to go between 32 degF (0 degC) down to -40 degF (-40 degC) then the rounslings should be perfectly dry otherwise ice may appear and can act as cutting and abrasive instrument which can cause internal damage to the sling and therefore reduce dramatically its performance as restraint system.

**Figure 4-1: Polyester Roundsling Application Chart**

At the end of a restraint line the roundsling must be anchored to a fixed point or to a heavy piece of equipment such as a separator. Note that the fixed point or piece of equipment should be strong or heavy enough that the dynamic force which could act on the sling will not break or pull it. Remember that in the case of moveable equipment which is not welded down, while a co-efficient of friction with the surface it is resting on will apply, items will slide with less force than would be needed to lift them – for example a 14 Tonne Separator may only need 7 Tonnes of force to drag it across the deck of a rig. The restraint system anchorage points must be considered during the job design phase and re-assessed during the rig up.

Post job the slings must be inspected to see if they are suitable for re-use. Any of the following damage is considered as a cause to remove and dispose of a Roundsling:

- Absence of an identification tag or part of the tag torn off or unreadable.
- Damage / chafing / cuts to the cover sleeve of the Roundsling which exposes the inner yarns (which are generally white in colour).
- Crush damage from hammer blows or loads having been set down on the roundsling.
- Signs of the Roundsling having been subject to any loading (Or knowledge of the restraint system having been subjected to loading of any sort).
- Chemical attack (exhibited by damage or discoloration of the cover sleeve).
- Heat damage. Evidenced by the jacket having a glassy appearance or hardening / stiffening. (Check especially any Roundslings which have been used on high temperature jobs or which may have been exposed to radiant heat from the burner, for this).
- Spatter damage from welding or grinding operations which have taken place close to the sling.
- Knots in the sling which cannot be untied.

Re-certification of Roundslings which are used for pipework restraint systems is not required.

## *4.4.10* Pipework Check Valves

In addition to the check valves which are integral parts of larger items of equipment (for example at the inlet of the Separator vessel, or in the Surge Tank Gas line outlet), stand alone pipework check valves may also be mandatory or required at other points in a Surface Well Test rig up (for example, in the line between the transfer pump and the oil diverter manifold, or on the flowhead kill line inlet). Usually these are a simple flapper and seat design, and although the flapper is spring operated, care should be taken when rigging up to make sure that the check valve body is positioned so that gravity is acting to close the flapper on the seat. The maintenance requirements for pipework check valves are given in Appendix B.4: Pipework Check Valve Maintenance and Certification.

## 4.4.11 API Threads

API threaded connections (e.g. EUE, Line Pipe) employ the threads as the sealing element. The potential danger with this seal is the exposure of the effluents directly on the threads. API threaded connections cannot be used in the presence of $H_2S$ as embrittlement will occur with exposure. This can cause the threads to fail and shear, thereby creating a potential for equipment failure.

API threaded connections are only permitted for single crossover applications from Testing Services to Client equipment, as long as the operating pressure is less than 3000 psi and the well effluents contain no $H_2S$. When testing on land API tubing may be used for open-ended flare lines and crossovers from a hammer union connection to the tubing thread will be required. For this situation an exception to the single crossover rule is allowed, and one crossover per line is permissible.

Any API threaded crossover required by Schlumberger Testing Services must be ordered via product centre and be maintained and certified as detailed in Section 2.5.1: RITE Maintenance and Tracking Definitions and in Section Appendix B.3: Pipework Maintenance and Certification. It is highly recommended to use a premium tubing thread rather than API EUE.

Crossover adapters from Hammer union to API or Non API tubing thread connections are non weight bearing.

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**Note**
When using tubing as flare lines, sufficient piping must be employed to clear the test area before crossing over to the tubing. Adequate securing and pressure testing of these lines is necessary and all risks associated with this type of operations should be covered in a HARC.

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## 4.4.12 Fittings

There are numerous types, styles, and specifications of fitting used in Testing Services. The fittings which are in contact with Well Fluids when used must be $H_2S$ Service. Other fittings, such as those used only for hydraulic control lines need not be $H_2S$ rated. Careful selection of fittings is required to ensure that the male and female parts are matched and that the assembled fitting is fit for purpose. Never mix fittings and never use them outside their intended application or WP range other than in a pressure test bay for the sole purpose of sealing off ports on equipment which is undergoing a test to Test Pressure for a Major Survey or Re-certification.

Schlumberger Testing also apply WP and maximum size limits for fittings.

| WP Range (Psi) | Thread Type | Maximum Size | Service |
|---|---|---|---|
| 0 – 285 | LPT | 4” | Standard |
| 0 – 2,160 ** | NPT | 1 1/2” | $H_2S$ |
| 0 – 3,705 ** | NPT | 1” | $H_2S$ |
| 0 – 6170 ** | NPT | 3/4" | $H_2S$ |
| 0 – 10,000 | NPT | 1/2” | $H_2S$ |
| 0 – 20,000 | Autoclave Medium Pressure | 1 | Standard |
| 0 – 20,000 | Autoclave High Pressure Sour service | 9/16” | $H_2S$ |
| 0 – 60,000 | Autoclave High Pressure | 9/16” | Standard |
| Check Fitting | Various – see list* | 1/2” | $H_2S$ |
| Check Fitting | Various – see list* | 1/2” | Standard |

* Fitting types include: BSP, JIC, Snap-Tite (a number of different series designations), Swageloc and Type “M”. The type and WP of each individual fitting MUST be verified before use.

** Some specific clients (Shell, for instance) mandate NPT fittings bigger than 1/2" being kept for WP only up to 285psi; this needs to be considered carefully during the job preparation and discussed with the client (ie: separator uses 3/4" NPT port)

Only forged stainless steel or better (e.g., Inconel) fittings which have been manufactured in compliance with internationally recognised standards, such as those defined by API, ASME, BS or EN may be used.

Check fittings – even if they are new - before use for any signs of poor quality manufacture (be especially aware of using counterfeit fittings or valves), damage, or stress.

Whenever possible the use of 3/8 or 9/16 Autoclave Medium Pressure is recommended for any application approaching 10,000 psi.

With the exception of 9/16 Autoclave, any fitting to be used at a WP of 10,000 psi or greater must be ½" or smaller.

Fittings for use with well fluids at 10,000 psi or greater must conform to API 6A specification.

As a minimum, all fittings should bear manufacturers markings which enable the WP of the fitting to be identified (either directly or by part number). Never exceed the manufacturer's rated working pressure. Never use components with no markings or traceability.

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**Warning**

Potential Severity: Serious
Potential Loss: Personnel
Hazard Category: Pressure

Be careful never to exceed the manufacturer's rated Working Pressure of any fitting during operations. For example many NPT threaded connections are not rated to 10,000 psi. Consult manufacturer for information on appropriate Working Pressure rating if it is not clearly marked.

---

**eg Example**

Example 1: if a manufacturer's Working Pressure rating of a 1/2 in. NPT fitting is 7800 psi, then the maximum allowed WP rating of the fitting is 7800 psi.

Example 2: if a manufacturer's Working Pressure rating of a 1/2 in. NPT fitting is 11,800 psi, then the maximum allowed WP rating of the fitting is 10,000 psi.

---

**Danger**

Potential Severity: Catastrophic
Potential Loss: Environmental, Personnel
Hazard Category: Fire flammable, Pressure

The installation of a needle valve, or of a fitting upstream of the needle valve, which has a lower WP than the WP of the equipment on which it is installed lowers the WP of the equipment to that of the valve or fitting. It is recommended good working practice to install valves or fittings which have a WP equal to, or greater than, the WP of the equipment even if it is not required for the job which is being performed. If a valve or fitting which has a lower WP than the equipment on which it is installed is used, it must be clearly identified with a tag and changed for one of a suitable WP at the earliest opportunity. Locations are strongly encouraged to standardise on 10 kpsi rated NPT needle valves and fittings for all applications other than those where Autoclave is required.

---

Fittings with the potential to be exposed to $H_2S$ must be compliant with NACE MR-0175.

Proprietary connection types such as Swagelok, A-lok pipe compression fittings should not be mixed even though some manufacturers claim interchangeability.

Never tighten/slacken fittings when a system is pressurized.

Never bleed system pressure by slackening fittings or connections. Use a bleed valve in the system.

Avoid combining or mixing fitting components from different manufacturers e.g. tubing, ferrules, nuts and fittings bodies.

---

**Warning**

Potential Severity: Serious
Potential Loss: Personnel
Hazard Category: Pressure

Ensure correct body positioning and hand placement when working with fittings. Bleedholes on pressure fittings, valve blocks, gauges etc. have the potential to eject high pressure jets of fluid (well fluids, water/glycol, nitrogen etc.).
These jets can inject fluid through the skin and into the soft tissues of the body. Entry point wounds may look insignificant however internal dispersal of fluids may be widespread through the body tissues.
**Immediate specialist medical attention must be sought in all cases** for specialized treatment to ensure all wounds are thoroughly treated and cleaned. If left untreated, these injuries can develop very serious medical complications.

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**Note**

It is acceptable to have 10,000 psi WP field equipment fitted with 1/4 inch or 1/2 inch NPT fitting as this equipment is only taken up to 15,000 psi Test Pressure inside a pressure test bay.

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## 4.4.12.1 Line pipe (NPT) threaded fittings

NPT fittings up to 1/2 in. nominal diameter may be used up to a maximum of 10,000 psi WP provided the manufacturer's Working Pressure rating is not exceeded. This is probably the most common type of fitting in Testing Services. Details on inspection and maintenance of this type of fitting are as follows:

**NPT Thread Gauging**

NPT threads must be gauged as part of the normal maintenance process to confirm they are fit for purpose. Below is the recommended method used to gauge both internal and external threads.

Gauges can be purchased via SRPC external sales.

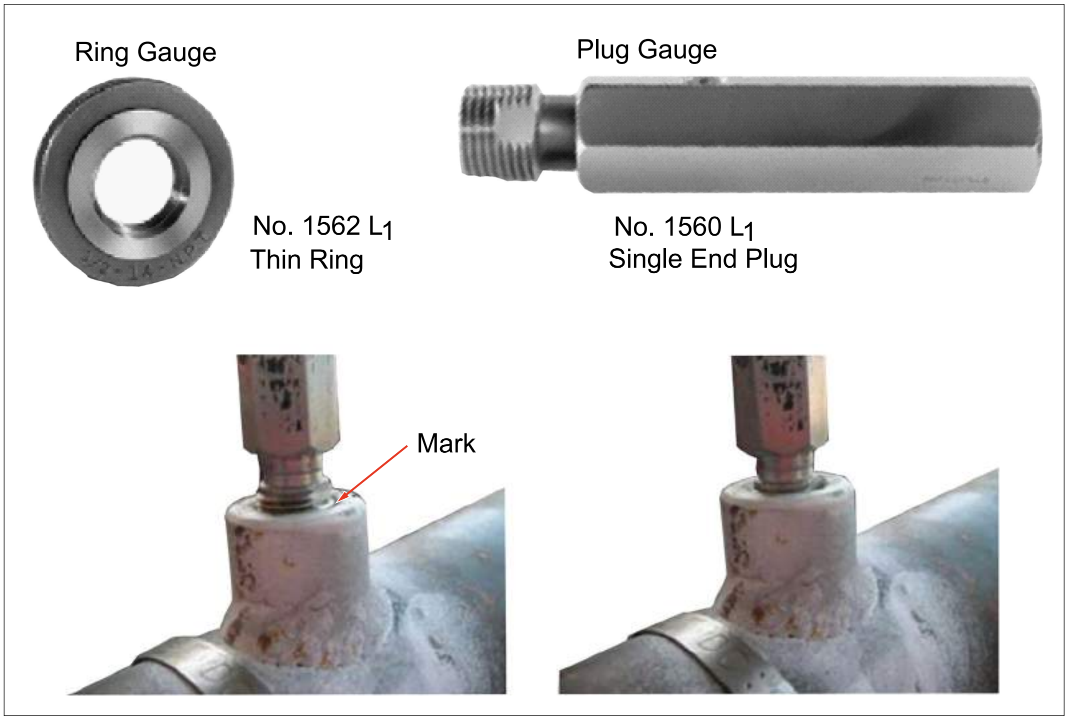


**Figure 4-2: Ring and Plug Gauge**

## ID and OD NPT gauging

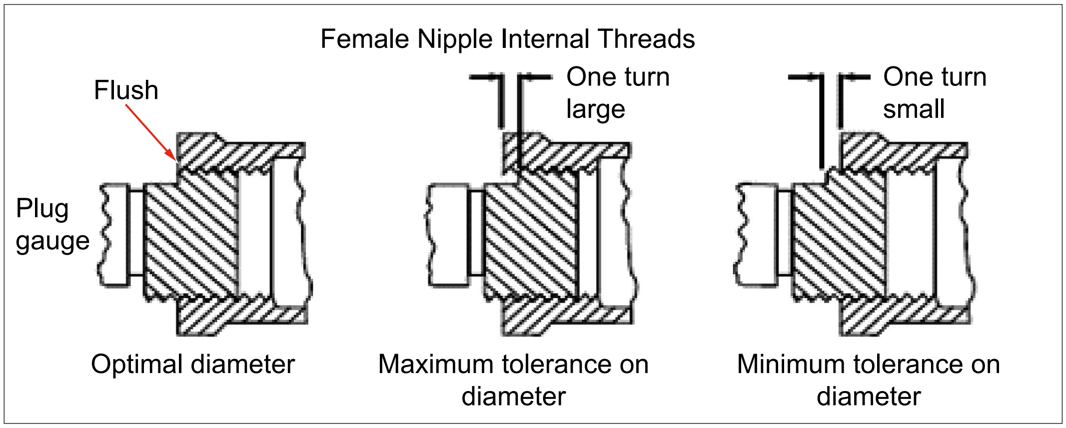


**Figure 4-3: Female Nipple Internal Threads**

For gauging internal taper threads, the plug gage is screwed up tight by hand into the internal thread of the product. The thread is within the permissible tolerance when the gauging notch of the working plug gage is not more than 1 turn, large or small, from being flush with the end of the thread.

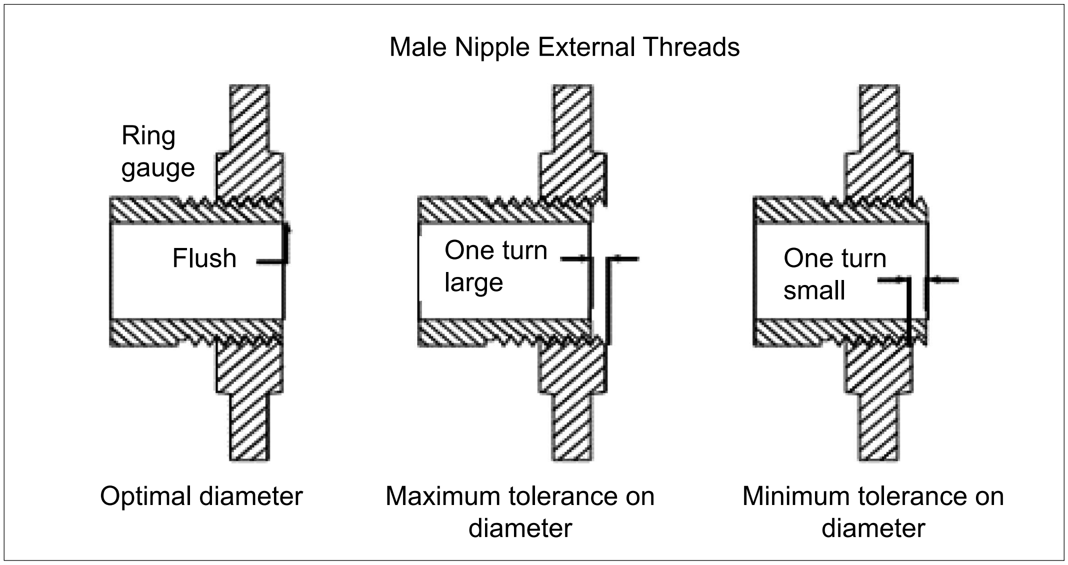


**Figure 4-4: Male Nipple External Threads**

In gauging external taper threads, the ring gage is screwed up tight by hand on external thread of the product. The thread is within the permissible tolerance when the gauging face of the working ring gage is not more than 1 turn, large or small, from being flush with the end of the thread.

## NPT Engagement Tolerances

**Table 4-8: NPT ASME (B1.20.1)**

| Nominal Size (in.) | Pipe OD | | Threads/ inches | Hand-tight engagement | Wrench-tight make-up |
|---|---|---|---|---|---|
| | in. | mm | | Threads/ Turns | Threads/ Turns |
| 1/16 | 0.31 | 7.9 | 27 | 4.3 | $2^{3/4}$ - 3 |
| 1/8 | 0.4 | 10.2 | 27 | 4.3 | $2^{3/4}$ - 3 |
| 1/4 | 0.54 | 13.7 | 18 | 4.1 | 3 - 3.1 |
| 3/8 | 0.67 | 17 | 18 | 4.3 | 3 |
| 1/2 | 0.84 | 21.3 | 14 | 4.3 | 3 |

**Note**

Included in the standards for NPT threads are the number of threads for correct engagement in both hand tight and wrenched up states. For example a 1/4 inch NPT fitting should screw in 4.1 threads until finger tight and 3 further threads for makeup with a wrench. As a general guideline for sizes up to ½ inch, after hand-tight engagment tighten a further 2 ¾ - 3 full turns for full make up.

## 4.4.12.2 Needle Valves

Needles valves are used on a wide variety of Testing Services equipment, including Flowheads, Data Headers, Choke Manifolds, and Separators. All needle valves must be $H_2S$ service. Thread size and WP limits of needle valves are the same as for general fittings.

**Danger**

Potential Severity: Catastrophic
Potential Loss: Environmental, Personnel
Hazard Category: Fire flammable, Pressure

The installation of a needle valve, or of a fitting upstream of the needle valve, which has a lower WP than the WP of the equipment on which it is installed lowers the WP of the equipment to that of the valve or fitting. It is recommended good working practice to install valves or fittings which have a WP equal to, or greater than, the WP of the equipment even if it is not required for the job which is being performed. If a valve or fitting which has a lower WP than the equipment on which it is installed is used, it must be clearly identified with a tag and changed for one of a suitable WP at the earliest opportunity. Locations are strongly encouraged to standardize on 10 kpsi rated NPT needle valves and fittings for all applications other than those where Autoclave is required.

## 4.4.12.3 Manifolds made from Fittings

Manifolds made up from fittings may consist of a mixture of valves, gauges, crossover or tee pieces and other fittings. Since the manifold is made from various components, the WP of the manifold as a whole is equal to the WP of the lowest rated component which is exposed to pressure. Numerous such manifolds exist within Testing Services operations - DST and SubSea pressure and function test manifolds, FSA sample manifolds and bottle pressure testing manifolds, SWT instrumentation manifolds or injection/sample point manifolds, pressure test manifolds, etc.

Because the majority of manifolds are locally made, they are sometimes cannibalized in order to make use of their individual components for other applications. This practice is counter productive and should be avoided. It is strongly recommended to keep the manifolds in a complete state, dedicated to a specific activity, and even assigned to one particular piece of equipment or toolset. The addition of a locally added identity tag with a serial number, WP, and application, will help in identification and tracking.

The component parts of each manifold should be inspected before use to ensure all the components of it are fit for purpose and that the stamped WP ratings match, or exceed, the Working Pressure rating of the equipment onto which it will be fitted. Manifold parts which do not have the original manufacturer marking or stamping for WP rating should be removed and junked.

## *4.4.13* Chemical Injection

It is mandatory for all Jobs where chemical injection is planned to perform a HARC. The possible effects of injecting the chemicals as well as the handling, storage, pumping, protective clothing, and environmental considerations must be addressed. The injection of any Oxidizing agent into the TS equipment is strictly forbidden.

Consult InTouchSupport.com for assistance especially when planning to inject highly flammable or poisonous chemicals.

### *4.4.13.1* Chemical Injection Lines

Chemical Injection connections to pipework or equipment must have a maximum nominal bore of 1/2 in. If two isolation valves are used, one check valve shall be included. If only a single isolation valve is used then **either** a close-coupled check valve **or** two check valves shall be included. Associated liners or piping should be stainless steel tubing or premium material compatible with the chemical injected. Steel liners or piping must be protected and secured to avoid whipping.

The pressure rating of liners depends on size, material and thickness and should be manufactured as per industry standards ASME, ASTM and API . Liner's pressure rating should be easily identified by proper marking. Refer to section 7.7.3: Metal Liners/Piping/Tubing Rules.

## 4.4.14 Transfer Pumps

A transfer pump is used to empty Gauge or Surge tanks, it can empty one compartment while the other is being filled. Pumps can also be used for pressure boosting when there is insufficient pressure to achieve atomization at the burner.

There are numerous types of transfer pumps in service, air operated diaphragm type and electrical or diesel driven centrifugal or screw types being the ones which are most frequently used. A common factor is that they are typically rated only for low pressure - generally 300 psi or less.

The installation of a check valve (or back pressure valve) is therefore mandatory between the pump and the oil manifold to ensure that at no time can the pump be subject to pressures greater than its working pressure.

## 4.4.15 Tanks

Flowing to and from tanks can be one of the most hazardous operations during well testing. The selection of a tank is dependent on location (on/offshore) as well as the expected flow rate and well effluent properties.

In all cases, and whichever type of tank is selected, the tank(s) must be grounded to eliminate static electricity, and resistivity measurements must be taken to check that the grounding is effective.

Gas or vent lines from any tanks must be run clear of the well test area. If the gas is not flared but cold vented, then a wind sock must be provided in clear view of the well test area so that the direction of the wind can be monitored. Based on this information, plus an estimation of the amount of gas coming from the tank, a continuous assessment of the position and size of the venting gas cloud can be made. If there is a risk of the gas cloud enveloping the wellsite, camp / accommodation, or any nearby settlement, operations must STOP and possible corrective actions reviewed.

### 4.4.15.1 Surge Tanks

Where $H_2S$ is expected only pressurized tanks (Surge Tanks) shall be used. During the job preparation phase it must be verified that the surge tank gas line is capable of accommodating the expected flow of gas from the tank, and the line must always have a suitable type of flame arrester installed. (See section 4.4.16: Flame Arresters).

It is also strongly recommended to install a flow restrictor upstream of the surge tank and downstream of the oil manifold. This will protect the tank in the event of gas blow by, and help maintain a constant oil line back pressure thus making separator level control easier.

Air should not be allowed to enter the tank as this may create an explosive mixture. This issue must be overcome by the use of nitrogen or separator gas to pressurize the tank while the pump is running. It is strongly recommended to perform a HARC so all potential risks are addressed and the best method for each particular job found. The nitrogen bottles or separator gas can be connected to the tank via liners and suitable pressure step down regulators. The purity of Nitrogen in each bottle to be used must be checked before use with a calibrated oxygen analyzer. The safe upper limit of oxygen concentration in the Nitrogen is 0.5%.

**Caution**
Potential Severity: Light
Potential Loss: Assets
Hazard Category: Machinery equipment hand tools

Use of external plastic tubing filled with liquid to monitor tank levels rather than rely on the magnetic level indicator is forbidden as it de-rates the tank pressure specification.

## 4.4.15.2 Gauge Tanks

Where $H_2S$ is expected, the use of a gauge tank to process reservoir fluids is forbidden and only pressurized tanks (surge tanks) shall be used. Gauge tanks are also forbidden for the processing reservoir fluids on offshore jobs.

Therefore to process reservoir fluids, they may only be used on land and if no $H_2S$ is present.

It is also strongly recommended to install a flow restrictor upstream of the gauge tank and downstream of the oil manifold. This will protect the tank in the event of gas blow by, and help maintain a constant oil line back pressure thus making separator level control easier.

Due to the possible introduction of oxygen into the Gauge Tanks which highly increases the risk of combustion reactions, Gauge Tanks vent lines must NOT be connected to a gas flare. Any deviation from this rule will require to have an exemption approved by Testing Services Headquarter. The detonation flame arrestors fitted on the gauge tanks are only for mitigation in case the cold vented is accidently flared. Although the Gauge Tanks have these detonation flame arresters permanently fitted on the tank roofs, whenever vent lines are to be extended, the optional flame end-arresters kits connected at the end of the vent hoses must be used to ensure low flame velocities protection by complying with the detonation flame arrester installation rule (distance from potential ignition point less than 50 times vent line diameter).

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**Note**

Gauge tanks are NOT DNV 2.7.1 certified.

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The hatches on top of a gauge tank, including those on the gauging (dipstick) ports, must remain firmly closed at all times, otherwise any gas inside the tank will escape through them, by-passing the vent system and flame arrestors, accumulating around the tank area, and increasing the risks of explosion and fire. It is strongly recommended that no liquid levels are taken via the gauging ports on the tank roof while hydrocarbons are in the tank. If this practice is necessary then a HARC must be performed and a specific procedure for dipping the tank put in place. The procedure must include an assessment of the wind speed and direction prior to each measurement and what will happen to any gas escaping from the tank through the open port. Ports MUST remain closed when not in use.

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**Note**

Although they operate at atmospheric pressure, gauge tanks are considered to be pressure containing devices and must only be purchased from a Schlumberger Product Centre.

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## 4.4.15.3 Frac Flowback (Trash) Tanks

Although not official Testing Services equipment, a number of locations use open top "Trash" tanks for FRAC flowback or sand clean out work to flow the returned Frac fluids, propant, or sand into. This is only acceptable for inert substances, and the flow of hydrocarbons from any TS surface equipment into any open top tank is banned. If a clean up flow from such an operation is required, the flowback to an open tank shall be limited to the point at which hydrocarbons reach surface. As soon as any hydrocarbons are detected, flow MUST be switched to an enclosed tank or be directed to a flare line, although flushing the contents of pressure rated solids separating equipment to an open top tank is still allowed.

All operations with open top tanks must have a windsock visible from the well test area for the purposes described in section 4.4.15: Tanks.

Storage of hydrocarbons or any other flammable liquid exceeding 10 liters in volume within open top tanks is banned.

## *4.4.16* Flame Arresters

Any ignition source creates an explosive opportunity for flame fronts to propogate back through the lines, destroying equipment and causing personnel injury. A flame arrester is a passive safety device designed to disperse any flame front and prevent it from traveling further along the line. There are two principle types of flame arrester, the detonation flame arrester and the deflagration flame arrester. It is the deflagration type of flame arrester which is supplied on boom lines and Gauge Tanks.

**Detonation Flame Arrester:**

Detonation flame arresters are designed to be located in the process line (with piping on both sides of them), normally at a distance which is more than 50 times the nominal diameter of the line from the potential source of ignition. The potential source of ignition is considered to be the point at which the gas exits the line. They offer protection against high flame velocities, where the velocity has become supersonic and is accompanied by a shock wave.

**Deflagration Flame Arrester:**

Deflagration flame arresters are available for both end of line and in line applications.

End of line deflagration flame arresters are located at the end of the pipe (with no piping after them) and are designed for protection against unconfined deflagrations. This style of deflagration flame arrester can also be supplied endurance burn proof and this is often used on storage tanks where long filling and thermal breathing can be present and the flow of the flammable mixture cannot be stopped.

In line deflagration flame arresters offer protection against low flame front velocities (subsonic speeds), and are located within the process line (with piping on both sides of them). This type of arrester must be installed in the line at a distance which is less than 50 times the nominal diameter of the line from the potential source of ignition, and the nominal diameter of the arrester must not be less than the nominal diameter of the line. The point at which the gas exits to atmosphere is considered to be the potential source (or point) of ignition.

## 4.4.17 Hazardous Areas and Zones

### 4.4.17.1 Hazardous Areas

A new zoning guideline based on API-505 using engineering & operational judgement, but also considering ventilation, is available on the latest Field Operating Handbook released under the InTouch Content ID 3916699 and must be followed accordingly.

The installation environment must be analyzed and classified as part of the risk assessment procedure. The wellsite is classified into zones, based on the likelyhood of ignitable concentrations of flammable gas or vapor under normal operating conditions.

The rig area classification must be discussed between Schlumberger and the rig supervisor during the site rig visit and prior to issuing the Surface Equipment Layout drawings. It is the rig supervisor's responsibility to provide zone classification depending on rig equipment, air intakes, living quarters, etc.

Table 4-9: Hazardous Area Characteristics provides values derived from the API standard that can be used as references for zoning classification under normal operating conditions.InTouch Content ID 3916699.

**Table 4-9: Hazardous Area Characteristics**

| | Hazardous Area Characteristics | Hydrocarbons Presence | |
|---|---|---|---|
| | | hours/year | %/year |
| **Zone 0** | A hazardous atmosphere is highly likely to be present and may be present for long periods of time | > 1,000 | > 10 |
| **Zone 1** | A hazardous atmosphere is possible, but unlikely to be present for long periods of time | 1,000 > 10 | 10 > 0.1 |
| **Zone 2** | A hazardous atmosphere is not likely to be present in normal operation or is present infrequently and for short periods of time | 10 > 1 | 0.1 > 0.01 |
| **Unclassified** | None – except abnormal condition | < 1 | 0.01 |

## *4.4.17.2* Non-Hazardous Area

Is defined as an area in which an explosive gas atmosphere is not expected to be present in quantities such as to require special precautions for the construction, installation and use of apparatus.

Testing operations will typically take place in an area which includes all 3 hazardous zones, and it may also include non hazardous areas. Care must be taken when designing the surface equipment layout, and also when rigging up, to make sure that the hazardous zones created by the rig equipment are compatible with the positioning of the Testing equipment, and vice-versa.

# *4.4.18* Fire Risk

In addition to pressure risks, it must be remembered that the risk of fire is always present during well testing operations, whether from stored chemicals, chemical injection or from flowing or venting hydrocarbons. Any time a piece of equipment is open to atmosphere for choke, filter or orifice plate change as well as sampling or flow check, the risk of fire increases.

Zoning philosophy needs to be respected and all sections of the process equipment should be evaluated for the risk of fire as well as pressure and $H_2S$, and documented in a HARC, with procedures implemented to reduce the risk of fire.

Depending of the location (off/on shore), and the spacing between the equipment, the following are some points to consider with regard to the risk of fire. This is not an exhaustive list, only a sample of pointers for consideration.

- Remember that Condensate or light oil has a greater fire risk than a heavy oil due to its increased volatility and lower flash point.

- Increase distances between equipment.
- Rig up with predominant wind in mind.
- Use blowers to disperse vapor or gasses where potential explosive mixtures exist.
- Vent lines must not end close to the rig air intake or hot surfaces (such as exhausts from engines).
- Shut down any welding, cutting or grinding operations during flow or sampling.
- Think about radiated heat from flare or burners.
- Consider the handling, storage, and fire detection of chemicals on the site.
- Review the storage of produced hydrocarbons (both small quantities like discarded BS&W samples, and large ones such as a Gauge Tank).
- Be careful of static electricity and equipment grounding,
- Use explosion proof electrical equipment (including hand held flashlights).
- Verify the presence and condition of spark and flame arresters on vent lines and gas lines.

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**Danger**

Potential Severity: Catastrophic
Potential Loss: Assets, Personnel, Process
Hazard Category: Fire flammable

Whenever performing flaring operations including on land jobs, a reliable and remotely operated pilot ignition system MUST BE installed and fully functional.

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### 4.4.19 Elastomers

The properties of the well effluent can have an effect on the durability of the elastomer seal fitted to the surface equipment. A number of different elastomer compounds are available and an elastomer seal which is suitable for the anticipated job conditions must always be used. More details on seal selection are given the SWT FOH at InTouch Content ID 3916699.

## 4.5 Wellsite Equipment Pressure Testing

Whenever surface-testing equipment is used at the wellsite, it must be pressure tested after it has been completely rigged up, before opening the well.

The pressure test should be considered successful if it meets the following criteria:

- no visible leaks,
- pressure is stabilized and holds steady within +/- 2.5% of the specified pressure for at least 3 minutes.

If the pressure decreases from the initial pressure and stabilizes, the pressure can be increased only one time to reach the required specified wellsite pressure.

In normal conditions, routing well flow through any section of surface testing equipment not pressure tested at the wellsite should be avoided.

If any component of the surface testing setup cannot be tested, an exemption request must be raised as per the Management of Change and Exemption Standard, SLB-QHSE-S010.

In case of partial rig down, as a minimum the connections broken and the critical pressure barriers must be retested.

## *4.5.1* Basic Wellsite Pressure Test (WPT)

Unless covered by an exemption, the Wellsite Pressure Test of the surface equipment upstream of the choke manifold shall be performed at a minimum of 1.2 times the MPWHP, but must never exceed either the Schlumberger equipment WP rating or the WP rating of the lowest rated tool or string component. The pressure tests of the surface equipment which is downstream of the choke manifold should be conducted at pressures which are in excess of the anticipated job operating pressures, but should not excede a pressure which is greater than 90% of the set pressure of any PSV, or the WP of any piece of equipment, in the section of the rig up which is being tested.

**Warning**
Potential Severity: Serious
Potential Loss: Information
Hazard Category: Pressure

The MPWHP is defined as being the maximum pressure, flowing or shut in, that the surface testing wellhead equipment could be subjected to during operations. It is determined by calculations in conjunction with the client and it is the greater of either:

- The maximum undisturbed reservoir pressure minus the pressure of a fluid hydrostatic column between the reservoir and the surface, where the pressure gradient of the fluid column may be based on the expected reservoir fluid properties, or if a worst case scenario is assumed, the pressure gradient of Methane gas. (0.1 psi/ft).

  or

- The maximum pressure which will be applied or created at surface during Bullheading, Fracturing, or other pumping operations.

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The Maximum Allowable Operating Pressures (MAOP's) on any given job are the pressures at which the Wellsite Pressure Tests were performed. Under no circumstances should the equipment be exposed to well fluid or dynamic pressures higher than the its' MAOP. For example, if equipment with a WP of 10 kpsi was pressure tested at 6 kpsi, the MAOP is 6K psi. If this is found to be insufficient for the operations being performed, it can be re-tested at a higher pressure, provided that this higher pressure is less than the equipment WP, and, for the equipment which is upstream of the choke manifold, the requirement for the pressure test to be a minimum of 1.2 times the MPWHP must also be respected unless the exemption process detailed in section is / has been followed.

ie. For surface equipment which is upstream of the choke manifold:

**MAOP = Wellsite Pressure Test Value = 1.2 MPWHP (unless covered by exemption), which must be less than or equal to WP.**

and for equipment downstream of the choke manifold:

MAOP = Wellsite Pressure Test Value, which must be less than or equal to WP (or less than or equal to 90% of the set pressure of any PSV in the tested section of the rig up).

Even if no wellhead pressure is expected, the equipment rig-up shall be tested at a minimum of 25% of its WP.

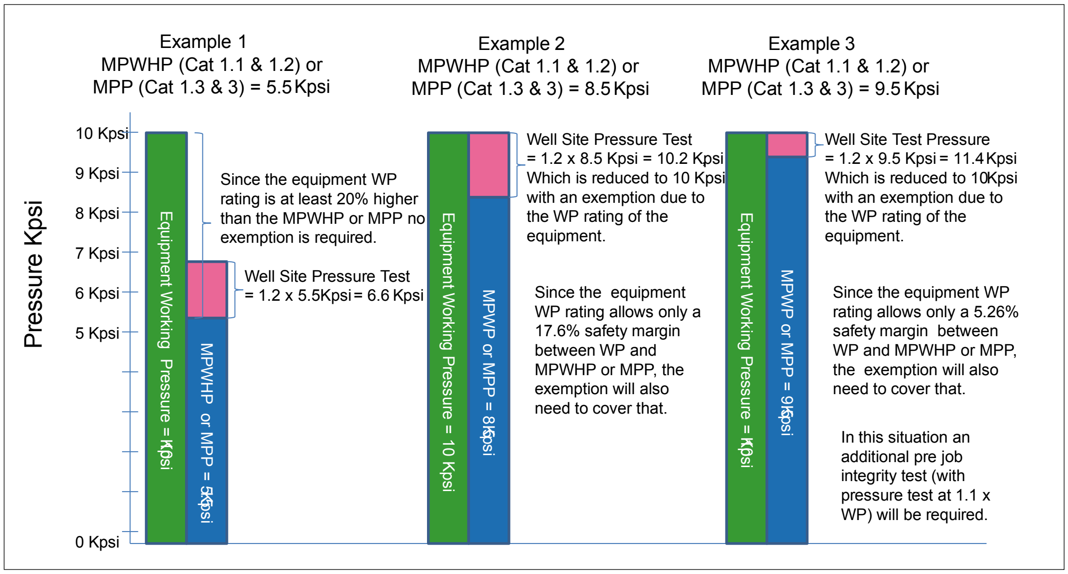


**Figure 4-5: Examples of the Wellsite Pressure Test for 10 Kpsi Equipment**

- See POM Section 1.7: Categories of Pressure-Containing Equipment for explanation of categories.

When pressure testing, any lower pressure lines than those being tested shall be kept open ended or vented to atmosphere to prevent over-pressuring in case of a leak. For elements protected by a pressure-relieving device or a pilot, the test pressure shall be limited to 90% of the PSV or HI-pilot setting or the pressure-relieving device shall be isolated or removed.

Pressure testing shall be carried out with a nonvolatile, non-compressible liquid such as ethylene glycol water based fluid. Refer to Section 1.9.2: Pressure Testing with Liquid: (Hydrostatic Tests).

The wellsite pressure test shall be recorded and noted on the service report.

Since wellsite pressure test naturally takes place in an open area (i.e. not in a pressure test bay), the area must be adequately secured by using warning signs, barrier tape and clearing the area from all unnecessary personnel while pressure testing is in progress. Refer to Section A.8 Pressure Tests Outside a Test Bay for further details and procedures.

When pressure testing the assembled process system (Surface equipment and pipelines), first fill the assembled equipment with the appropriate test liquid; making sure all air is bled from the system. The pressure testing shall start with a body test of the whole system and an initial low-pressure (~200-300 psi if practicable) test should be made for a duration of at least 3 min or the entire time needed to verify that there are no obvious leaks.

On completion of a successful low-pressure test, the test pressure shall be brought up slowly until the final test pressure is reached. The final test pressure shall be held, as a minimum, for 10 minutes. Unexplained pressure drops shall be sufficient reason for the test to be repeated. Retests shall apply the same procedure as the original test.

Valves should be operationally tested.

Detailed procedures for wellsite pressure testing are to be found in maintenance manuals or field operations manuals.

The Testing Services Supervisor or Chief Operator must be present during wellsite pressure tests conducted by a third party pump unit. Testing Services personnel leading the pressure test must be pressure certified to at least level 2 for pressures up to 10K, and level 3 for pressures above 10K.

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**Danger**

Potential Severity: Major
Potential Loss: Personnel
Hazard Category: Pressure

Never attempt to closely inspect or repair any leak while equipment is under pressure. Tightening or slackening of connections, moving the pipework, or similar operations while the pipework contains pressure shall not be performed under any circumstances.

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## 4.6 Special Operations

### 4.6.1 $H_2S$ Operations

Table 4-10: $H_2S$ Equipment Rating is to be used to determine if $H_2S$-rated equipment is required for an operation:

**Table 4-10: $H_2S$ Equipment Rating**

| Concentration of $H_2S$ (ppm) | Unknown | $H_2S$ S≤770 | 770< $H_2S$ ≤150,000 | |
|---|---|---|---|---|
| Equipment Service | $H_2S$ Equipment | $H_2S$ Equipment if PP > 0.05 or Job > 24 hr | $H_2S$ Equipment if WHP > 65 psi or Job > 24 hr | $H_2S$ Equipment |

**Note**

$H_2S$ Partial Pressure (PP) = Total Pressure (WHP) (psia) x $H_2S$ concentration (ppm) x 1/1,000,000

The following additional rules apply to operations where $H_2S$ is expected or suspected:

- $H_2S$-rated equipment shall be used on all wells having the potential to produce $H_2S$ in unknown concentrations. If the $H_2S$ concentration is known, $H_2S$ service equipment is to be used according to NACE MR-0175. Refer to Appendix D.
- $H_2S$ operating safety rules, as per Wireline and Testing $H_2S$ manual, are to be followed on any job where presence of $H_2S$ is expected. All personnel must be $H_2S$ qualified. $H_2S$ monitoring equipment must be installed and operative.
- All $H_2S$-rated equipment must conform to NACE MR-0175. Flow-through threaded connections (where the seal is done on the threads) exposed to well fluids are not acceptable except as outlined in 4.4.11: API Threads.
- Any piece of equipment which cannot be positively identified as $H_2S$-rated shall be considered not suitable for $H_2S$ Service.
- Repairs and modifications to $H_2S$-rated equipment can only be carried out in qualified shops, approved by a Schlumberger Testing Services Technology Center. Welding must conform to NACE rules (refer to Appendix C local manufacturing and repairs).
- The use of gauge tank is forbidden where $H_2S$ is expected. Only pressurized tanks (surge tanks) shall be used. The surge tank vent line shall always be fitted with a detonation arrestor.
- If $H_2S$ is present, the use of produced gas to supply any equipment (including instrumentation) is forbidden.
- Windsocks must be strategically placed to allow viewing from operating areas.

## 4.6.2 Nighttime Operations

The following recommendations apply to nighttime operations in areas where a normal day/night cycle takes place in a 24 hr period:

1. No nighttime testing job should be initiated by a crew that has had less than 8 hr rest in the last 24 hr.
2. No first-time flow (Hydrocarbons) through surface equipment shall be initiated after dark.

   Exceptions to this rule must be approved by Geomarket Operations Manager.

3. Jobs with established pressure (well cleaned-up and stabilized) may be continued after dark provided adequate lighting is available to illuminate all possible areas in which leaks could develop, all areas where remote controls are located and suitable escape paths away from the wellhead. Local procedures for such jobs must be agreed beforehand with the customer representatives and additional lighting procured as required.
4. Production tests or other workover operations with no permanent installations or drilling rigs are forbidden during darkness hours. Location Operations Manager can approve an exempt provided a risk evaluation with proper HARC was completed. For high-latitude operations where daylight periods may be very short or nonexistent, a specific procedure must be established by the concerned GeoMarket, based on the “adequate lighting “principle.

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**Note**

Painting the lever type valve handles on the separator and diverter manifolds in bright colours or neon paint will help to identify the valve position when the lighting or visibility is marginal.

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## 4.6.3 Operations in or with Extreme Cold

Extreme cold can either be generated by the operations themselves (for example by the Joule-Thomson effect as a fluid passes through a choke and expands) or can be climate related. In either case the operating conditions are frequently refered to as "Arctic Operations". These operations shall be evaluated to ensure that the temperatures do not fall below the design range of the metallic and polymer components.

Arctic operations are carried out usually down to -40°F [-40°C] ambient temperature and sometimes as low as -70°F [-57°C]. Operations in sub-freezing weather require special precautions with respect to equipment, procedures and personnel safety. There is no officially accepted definition of cold weather/ extreme cold /arctic environment, but a widely used one is when temperature goes below -20°F [-29°C].

**Danger**

Potential Severity: Catastrophic
Potential Loss: Assets
Hazard Category: Pressure

Particular care is needed when operating equipment in Arctic Operations as all materials become brittle at low temperatures. The rapid cooling produced by the Joule-Thomson effect can also create additional stresses in the material due to uneven cooling - for example the choke box on a choke manifold will cool much more quickly than the rest of the manifold. Avoid hammering heavily on the choke box cap or any hammer union pipework if Arctic conditions are being experienced.

Detailed arctic operations guidelines are outside the scope of this document, however the following general recommendations apply:

The following recommendations apply to cold weather/arctic operations:

1. **Materials performance in extreme cold**

   The minimum Design Temperature of Standard Surface equipment is -20°F [-29°C] according to API, ASME and ANSI construction codes.

   **Note**
   Some clients and some regulatory authorities (e.g., NPD in Norway) have requirements in excess of what is stated in the reference construction codes.

   Special equipment and materials specially treated and qualified shall be used below -20°F.

   For Arctic operations, the equipment specification and the local certification requirements shall be carefully reviewed to verify the specifications are adequate for environment and comply with local regulations.

   Standard elastomers become hard and brittle. Arctic specification O'rings that can energize down to -70°F and arctic specification hoses for hydraulics and chemical injection are available for arctic environment.

2. **Problems with hydrates or icing at low temperatures**

   The very low ambient temperatures increase the probability of plugging through icing and/or hydrates. Even in low GOR wells, gas can segregate during shut-in periods and produce plugging hydrates when coming in contact with untreated water. Any water used for pressure testing or otherwise pumped into the test string, must be mixed with ethylene glycol or other antifreeze compound in suitable proportions for the minimum temperature expected. Injection ports and suitable injection pumps for hydrates/ice inhibitors shall be available in several locations on the flow path (starting at the Subsea-Tree when available). Common antifreeze compounds are methanol and ethylene glycol. Methanol is more efficient in eliminating already formed ice/hydrate plugs. Every effort must be made to maintain the effluent at a temperature above freezing or hydrate formation points.

Whenever possible, the well test process equipment should be located indoors. Ventilation and safety system must be designed accordingly. If the equipment is located outdoors, thermal insulation, heat tracing of pipes with steam and steam coils in separators and tanks must be planned. Additional steam hoses should be available to cope with unforeseen freezing areas.

All lines must have drain valves installed at their lowest point and nipples to enable purging. Pressure gauges must be installed between each piece of equipment in the process system to allow early detection of plugging conditions.

Temperature behavior across choke manifold, heater and separator must be closely monitored and maintained above hydrate freeze temperature. Pressure must be dropped in stages by using the heat exchanger adjustable choke in addition to the choke manifold, while taking care to maintain critical flow.

Nitrogen should be available to flush lines to the flare.

Hydraulic oils in hydraulic actuators must be chosen so that their viscosity remains in a workable range at low temperatures. Avoid small diameter hydraulic hoses on shutdown systems.

Additional condensate traps must be installed on the air supply and methanol injection considered if there are indications that the rig air supply is not totally dry.

## *4.6.4* HPHT / HQ Operation

HPHT operations are defined as any operation above 8000 psi MPWHP and/or above 250 deg F MPWHT.

HQ High Flowrate operations are defined as any operation above 8000 BPD and/or 30 MMSCF/D.

Usage of ArchiTest for such test design is mandatory.

HAZOP shall be used for all HPHT/HQ operation.

For high pressure/high temperature (i.e. above 8000 psi and/or above 250 deg F) and/or high rate well tests, a HAZOP and a well test design review must be carried out for each test. The well test design review shall be based on the safety analysis techniques defined in API RP 14C and emergency shutdown systems designed accordingly.

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**Note**

During HPHT or HQ operations, it is advisable to remove the thermowells or any other intrusive probe from the flow stream to reduce the risk of wash out and venting hydrocarbons to atmosphere.

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## *4.6.5* Solids Production

Production of solids can be detremental to the equipment condition. In addition to causing plugging of the choke, sample points, or instrumention liners, it can also erode the inside of the pipework, manifolds, and larger items of equipment. The abrasive force of the solids in the well effluent will increase with the velocity of the fluids. The places most likely to errode are therefore pipework elbows and Tees, bypass and diverter manifolds which are downstream of the choke manifold. If the well produces solids, the wall thicknesses of the pipe and equipment most vulnerable to erosion shall be checked at least once every 2 hours irrespective of whether or not a sand filter is being used.

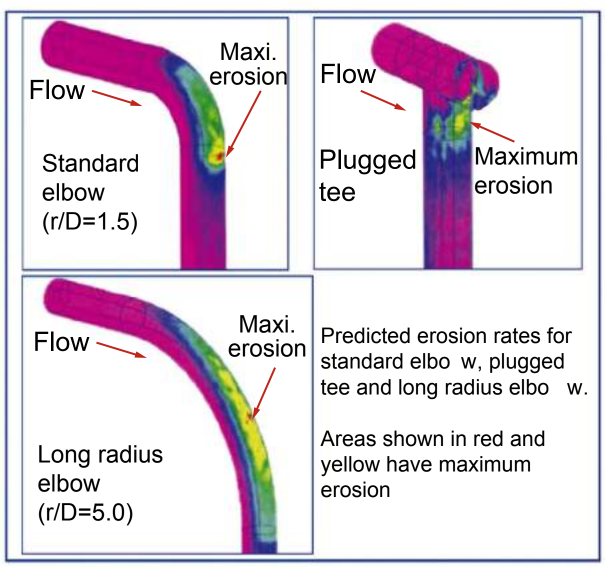


**Figure 4-6: Erosion**

Architest should be used to determine the erosive effects of solids production on the pipework rig up for the job and to help determine the frequency at which thickness checks should be made.

A number of third party companies can supply sand detection equipment. Please refer to InTouch Content ID 5958396 for selection and guidelines.

# 4.7 Safety Certification, Shop Maintenance and Quality Control

In case of subcontracting (such as Schlumberger Technology Centers decentralized manufacturing), the responsibility to ensure availability of documentation (i.e. material traceability and Quality file) rests with the main vendor (i.e., the Technology Center).

## 4.7.1 Major Re-Certification

All pressure-containing and pressure-controlling Surface Equipment shall undergo a Major Re-Certification after five years in service.

Re-Certification means a detailed survey and performance verification conducted by (or under control of) a certification agency, leading to re-certification.

Table 4-11: Major Re-Certification Requirements for Surface Well Test Equipment and Table 4-12: Major Re-Certification Requirements for Surface Well Test Equipment give examples of Major Re-Certification requirements for surface well test equipment.

Refer to maintenance manuals and certifying authority or local regulations for more detailed and complete procedures and requirements. In any case where a conflict exists between requirements given in different documentation, the most stringent requirements shall be followed.

**Table 4-11: Major Re-Certification Requirements for Surface Well Test Equipment**

| Item | Flowhead | Surface Safety Valve | Choke Manifold | Pipework* Crossovers | Gas & Oil Flowlines |
|---|---|---|---|---|---|
| Visual inspection | √ | √ | √ | √ | √ |
| Wall thickness random checks | √ | √ | √ | √ | √ |
| Hydrostatic test at Test Pressure | √ | √ | √ | √ | √ |
| Hydrostatic test at Working Pressure | √ | √ | √ | NA | NA |
| Operational test at Working Pressure | √ | √ | √ | NA | NA |

| Item | Flowhead | Surface Safety Valve | Choke Manifold | Pipework* Crossovers | Gas & Oil Flowlines |
|---|---|---|---|---|---|
| NDT test of load bearing threads | √ | NA | NA | NA | NA |
| NDT test of pad eyes | If Applicable | √ | √ | NA | NA |
| Lifting proof load test | NA | √ | √ | NA | NA |
| Review of Quality File | √ | √ | √ | √ | √ |

* For detailed instructions, refer to Appendix B: Surface Well Testing Pipework and Flexible Hoses.

**Table 4-12: Major Re-Certification Requirements for Surface Well Test Equipment**

| Item | Heat Exchanger | Separator | Surge Tank | Burners | Burner Boom | Baskets and Containers |
|---|---|---|---|---|---|---|
| Visual inspection | √ | √ | √ | √ | √ | |
| Wall thickness checks of vessel and pipework | Including coil | √ | √ | | Water and oil lines | |
| Hydrostatic test at Test Pressure | Coil, shell and pipework | √ | √ | √ | √ | |
| Hydrostatic test at Working Pressure | √ | √ | √ | | | |
| NDT crack test of pad eyes | √ | √ | √ | √ | All structural welds | √ |
| Lifting proof load test | √ | √ | √ | √ | √ | √ |
| Review of Quality File | √ | √ | √ | √ | √ | √ |

## 4.7.1.1 Equipment Obsolescence

Surface testing equipment shall be retired before a 4$^{th}$ Major Survey is required, this is typically after 20 years of service. The exception being burners where the retirement age is 15 years. Any deviation from this must be approved through an exemption in QUEST, approved at Area level, with a strong justification as to why the asset should not be retired.

Quality files (Equipment manufacturing pack) retained at the product centre for surface well testing equipment shall be disposed of when greater than 20 year of age.

## 4.7.2 Regular Inspection and Annual Surveys

Testing Services owned Surface Testing Equipment must be initially qualified by an inspection and hydrostatic test at reception. This must be done according to TRIM check procedure and qualified for use by Annual Surveys.

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**Note**

For Surface Testing Equipment, the verification procedure shall be carried out after every job (TRIM) where the equipment has been submitted to extraordinary conditions, rough handling (bending, accidental drops, corrosive fluids, large $H_2S$ or $CO_2$ concentrations) or after replacement of pressure-containing or pressure-controlling parts. All erosion prone components must be inspected after every job where sand was produced.

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The Annual Survey must be recorded in the Quality File, following the rules set forth in Section 2.5: Asset Maintenance - RITE and a band or plate giving the date of last test attached to each individual piece of equipment.

Detailed Survey instructions are contained in the maintenance manuals. Piping shall follow the Mandatory Piping Colour coding for Annual Survey set out in Section .

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**Note**

Having a certifying authority witness the annual survey is not required by this standard but may be required to meet local regulations or customer requirements.

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Annual Survey general procedures are as follows:

- Thoroughly clean all components.
- All threads and sealing surfaces shall be cleaned with wire brush or fine emery cloth.
- All threads and sealing surfaces shall be checked for damage.
- All valves shall be disassembled, to inspect all parts for damage or corrosion. All damaged parts shall be replaced.
- All rupture disks shall be replaced.

- All inlet and outlet tees, elbow, etc., where maximum erosion is to be expected, are to be checked for thickness loss. Limits of ID are given in .
- All Hammer unions (either piping or attached to main assets) shall be inspected following procedures set out in Section .
- Fixed separator and surge tank piping must go through annual survey in accordance with the same requirements in respect of thickness testing and inspection as surface piping, but the pressure test to should be to the same value as the WP of the vessel to which it is attached. This means that the fixed piping does not need to be disconnected from the vessel and the whole assemply can be pressure tested at the same time.
- For large vessel inspections, refer to appropriate maintenance manual and to API Standard 510: Pressure Vessel Inspection Code.
- All elements shall be visually inspected for signs of damage, stress and surface defects. If any defect is observed the equipment shall be replaced and set aside for full NDT inspection and, if required, subsequent remanufacturing where certified repair facilities are available (refer to Appendix C) or be junked.
- All pressure safety valves (PSV) shall be inspected and recalibrated every 12 months.
- More frequent inspection and re-calibration of the PSV might be required due to job exposure or local regulations. Re-calibration must be certified by Third Party .
- After inspection and reassembly, the equipment shall undergo a hydrostatic body test and an operating seat test.
- Hydrostatic Body and seat tests for valves and operating tests shall be conducted at rated Working Pressure (WP). The exception is piping, it shall be pressure tested to Test Pressure (TP) during the annual survey.

## 4.7.3 General Pressure Test Procedures are as follows

- Detailed procedures for pressure testing are covered in the maintenance manual.
- Qualified personnel shall carry out pressure tests exclusively in specially designed pressure test bays. It is acceptable to subcontract routine testing to reputable contractors or certifying agencies.
- All adapters, flanges, etc., must be tested. Valves must be in the partially open position during the body test. Test plugs with a pressure rating equal to or higher than the equipment being tested must be used to cap open-ended components.

- Relief valves, rupture discs and all accessories not designed to withstand test pressure must be blanked off or removed and replaced by suitable plugs. (i.e., separators level troll floaters must be removed).
- Unless there is a specific requirement for a pressure test with gas, pressure tests should be performed with a nonvolatile, nonflammable, low compressibility liquid such as water or ethylene glycol.
- All air must be bled from the system.
- Test pressure must be introduced slowly, and held for a minimum of 3 min (primary holding period) after the pressure has stabilized at TP value and the equipment and pressure gauges have been isolated from the source of pressure.
- Test pressure is bled to 0 psi.
- Test pressure is reintroduced and held for a minimum of 15 min (secondary holding period).
- Test pressure is bled to 0 psi again.
- After the hydrostatic body test, all equipment with moving parts shall be tested again at rated Working Pressure and operated a minimum of two times to ensure that it functions properly.
- Each bi-directional valve seat must be tested from both sides at rated Working Pressure, with one side open to the atmosphere.
- If equipment has to be gas tested, it must first be pressure tested to at least 1.2 times the pressure required for the gas test with a non-compressible (Hydrostatic) fluid. In no case, can the pressure test with gas exceed the rated WP of the equipment being tested. Gas tests have an inherent higher level of risk and safety precautions must be increased accordingly.
- In certain areas (e.g., North Sea), certifying authorities demand a low-pressure gas test across the seals of **Category 1** equipment valves. In this case, the test shall consist of two 15 min holding periods, the first at rated Working Pressure, the second at 300 psi. Valve bodies shall be completely immersed in a water bath during the test.

## *4.7.4* Major Repairs/Remanufacture

Refer to Appendix C.

## *4.7.5* Equipment Identification

Each individual subassembly of surface testing equipment shall be identified as per Section 2.4: Asset Management.

# 4.8 Equipment Procurement Guidelines

## 4.8.1 Purchase of New Equipment

All pressure-containing and pressure-controlling equipment including crossovers and surface piping shall be purchased exclusively through Schlumberger Product Centers.

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**Note**

Although they operate at atmospheric pressure, gauge tanks are considered to be pressure containing devices and must only be purchased from a Schlumberger Product Centre.

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Other surface equipment bought directly from approved vendors, must comply with Standards listed in Section 4.2.1: General Standards and specifications set by Schlumberger Technology Centers.

Special adapters and connections can be purchased from TC approved vendors. Testing Services Rapid Response must approve purpose-built systems necessary to comply with special client requirements prior to committing to a purchase. The request for approval must include complete purchasing specifications.

The location purchasing the equipment is responsible for checking and identifying all local certification requirements and specifically requesting the necessary certifications at time of ordering.

Requests for special lifting / handling subs such as flowhead lifting/handling sub must always be entered through OneCAT to Rapid Response.

The design and standard shall always ensure the same or better mechanical caracteristics than the original lifting sub (pressure, temperature, tensile, API6A, PSL3, PR2, Fluid class, Temp Class, NACE, etc...)

## 4.8.2 Rented Testing Equipment

Surface equipment may be rented from a rental agency if the policy in Section 2.3.2: Rented Equipment is respected.

### 4.8.3 Client-Supplied Equipment

Particular attention must be given to rig-installed piping sometimes owned by the drilling contractor. Rig-installed piping shall have a valid inspection and pressure test certificate proving compliance to Schlumberger standards. If the equipment does not conform to these guidelines, client shall be made aware of the reasons for non-conformance.

## 4.9 Personnel Certification

### 4.9.1 Surface Testing Crew

All well testing operations shall be performed exclusively by pressure-qualified crews. This applies to each shift when 24 hr manning is required.

A crew operating surface testing equipment is qualified if the crew has a valid pressure certification as prescribed in Section 9: Testing Services Personnel Qualification and Administration.

Surface testing pressure certifications are:

- **Pressure Level 2 Surface Welltest Certification** - Pressure certification for SWT (equipment operation) for all operations below HPHT / HQ limits.
- **Pressure Level 3 Surface Welltest Certification** - Pressure Certification for SWT (job design and equipment operation) for HPHT / HQ operations. Replaces the “Advanced Surface Welltest” certificate.

Additional details on certification procedures are given in Section 9: Testing Services Personnel Qualification and Administration.

In addition to the above, operators must be $H_2S$ certified, as per the $H_2S$ manual, for any operation where $H_2S$ is expected.

4.10 # Section 4 Revision History

For more details see Appendix F.

**Warning** Potential Severity: Serious
Potential Loss: Security
Hazard Category: Human

The controlled source document of this manual is stored in the InTouch Content ID 3045666. Any paper version of this standard is uncontrolled and should be compared with the source document at time of use to ensure it is up to date.

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# Subsea Safety Equipment

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# 5 Subsea Safety Equipment

This section covers the policies and guidelines pertaining to the use of Subsea Safety Equipment, falling into Category 1.3.

All Schlumberger Testing Services-operated equipment used for containing and controlling well pressure and well flow during production, from the seafloor level to the flowhead, is covered under this definition. The flowhead is covered under Section 4: Surface Equipment. This section covers the E-Z Valves, SenTREEs, Retainer Valves, Lubricator Valves and associated equipment, such as slick joints, fluted hangers, crossovers, etc.

## 5.1 Overview

All Subsea safety equipment used by Schlumberger shall be pressure rated. Being part of a pipe string (i.e., load bearing), Subsea safety equipment shall also have a tensile rating (pulling load). The total combined load (tensile and pressure) must always be considered.

The pressure rating is expressed as a Working Pressure (WP) and a Test Pressure (TP). WP is defined for a given temperature range (e.g., 38 °F to +325 °F) and for a given pulling load. It is forbidden to submit any piece of Subsea safety equipment to a pressure higher than its WP rating during operations.

The maximum allowable pulling load is a function of both pressure and temperature. It is given at 0 psi and at ambient temperature and must be de-rated taking into account actual operating internal pressure and temperature. Refer to the appropriate equipment manual.

It is recommended for the landing string (from the surface flowhead to the major string) to be analyzed as a system to identify the overall weak point and to confirm system compatibility with worst-case combinations of tensile and axial loading with respect to maximum potential pressures. At a minimum, it must be confirmed that the client has conducted this analysis.

In a system assembly of different components, the WP of the weakest component gives the overall Working Pressure rating of the system and the element with the lowest tensile rating gives the maximum overall pulling load.

**Note**

Schlumberger Subsea safety equipment tensile rating is defined with respect to the minimum yield stress. Some manufacturers' published ratings are based on ultimate tensile strength, giving an optimistic figure.

## 5.1.1 Test Pressure

During manufacturing, All Subsea equipment (excluding equipment designed to 5CT) is subjected to a 1.5 times maximum WP hydrostatic. Proof-test at the Schlumberger Testing Services Technological Center or at original supplier. This test is conducted with all valves open. Valves are only tested at WP as per API Specification 6A. All pressure tests after the original proof tests are to be conducted as per Table 5-1: Maximum Recommended Test Pressure for Subsea Safety Equipment. Crossovers to landing string tubulars are not designed and tested to this standard. Refer to Section 5.6: Tool Joints and Crossovers.

**Table 5-1: Maximum Recommended Test Pressure for Subsea Safety Equipment**

| | Major Survey (Hydrostatic) | Annual Survey | TRIM Checks | Fit Checks |
|---|---|---|---|---|
| **Bore Test with all Valves Open** | 1.2 × WP | 1.1 × WP | WP | WP |
| **Pressure across Valves** | WP | WP | WP | WP |
| **Equipment Designed to 5CT** | FAT Test Press. | WP | WP | WP |

Pressure Testing at major survey of assets in accordance with original FAT procedure and pressure test values are to be done as detailed in GeMS document 100282338.

Maintenance guidelines for Subsea equipment follow the RITE methodology of FIT, TRIM, Q-check, etc. Subsea assets and the associated maintenance must be tracked in RITE. Specific maintenance details are given in relevant maintenance or operations manuals.

The maximum Working Pressure (WP) rating of a system is defined by the lowest WP rating of any component within the system. For example, in the SenTREE 7 assembly it is common for a project specific component such as the latch mandrel to have a lower WP rating than some of the other components. In this case, the maximum WP rating of the SenTREE 7 system assembly will be the same as the WP rating of the latch mandrel.

### 5.1.2 Service Type

Typically Subsea Safety Equipment assets manufactured by Schlumberger Testing Services is designed for $H_2S$ service as per NACE MR-0175, for a minimum design handling temperature of -20 °F and for a maximum operating temperature as specified per tool.

Non-NACE job specific components, such as crossovers, spacer subs and slick joints, can be supplied if the reservoir is known to be free of $H_2S$.

## 5.2 Standards and Specifications

Subsea safety equipment used by Schlumberger Testing Services complies with one or more of the following standards:

- API 5CT.
- API Specification 6A / ISO 10423:2009 (Modified).
- API Specification 14A5.
- API Specification 17G / ISO 13628-7.
- NACE MR-0175.

All equipment designed by Schlumberger Testing Services Technological Centers after 1990 conforms to:

- UK Statutory Instruments SI 913 “Design and Construction regulations” (replacing SI 289) and HSE Guidance Notes.
- DNV: rules for classifications of mobile offshore units, “Offshore Standard DNV-OS-E101, Drilling Plant”.

All Subsea Test Tree Valves shall be built and tested to a minimum of API Specification 6A / ISO 10423:2009 (Modified) PSL-3.

## 5.3 Job Design and Well Integrity

Maintaining the integrity of a well is paramount in delivering a safe, high quality, service to our clients. In addition to following all the measures required to maintain the integrity of individual tools (such as maintenance, certification and traceability of critical parts), at the wellsite the overall Well Barrier Envelope must be established and maintained, and in order to do this all jobs performed with Subsea equipment must be designed and planned in accordance with

POM section 3.2: Job Design, and Planning Well Barriers. The roles and responsibilities of each member of the crew must also be assigned, and this must take into consideration their levels of training and competence.

## 5.4 Subsea Safety Equipment General Rules

A Subsea Test Tree shall be used on Subsea wells being tested or flowed to surface for any reason. Any variation must be approved through the QUEST exemption process (SLB-QHSE Standard 10).

Two testable pressure barriers between reservoir and the environment should be maintained during all phases of planned and contingent operations. This should be the case for both the annulus and also the tubular wellbore.

Two annular pressure barriers should be considered with respect to all Subsea wells. This is commonly provided by dual BOP ram closure on the slick joint for SenTREE3 operations. For SenTREE7/HP Completion operations, it should be considered that when the TH (Tubing Hanger) is set, the annulus isolation sleeve seals and TH seals, plus the AAV (Annulus Access Valve) and XOV (Crossover Valve) in the HXT (Horizontal Christmas Tree) are the primary annulus barrier, and the pipe rams which are closed on the PSJ (Ported Slick Joint) are considered to be the secondary annulus barrier. At least one barrier test must be conducted in the well prior to any lifting or flowing the well.

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**Note**
Annular preventers are not considered as well barriers.

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A fluid is considered a barrier if the hydrostatic head of the fluid is greater than reservoir pressure and the height of the column can be monitored, with a reserve of fluid available for immediate use should it be required in order to maintain the height of the column. A job or project specific Hazard Analysis and Risk Control should be performed to identify and mitigate risks, particularly the risks associated with barriers for the annulus and the tubular wellbore.

Any variations from the two pressure barrier policy must be reviewed with the Client and operational management during a Hazardous Operation Review. Contingent operations must be clearly identified; rig personnel trained to comply with contingency plans and measures must be taken to mitigate any risk.

It is recommended to contact InTouchSupport.com if assistance is needed with hazardous operations planning.

### 5.4.1 Use of a Retainer Valve

Having a subsea Retainer Valve in the landing string is Mandatory in any of the following cases:

- HPHT conditions.
- High Flowrate (Gas > 30MMSCF/D, liquid > 8,000 bbl/d).
- $H_2S$ expected.
- Whenever a DWCS system is deployed.
- Water depth > 500 ft.
- Where the Maximum Possible Pressure (MPP) inside the landing string at the SenTREE is greater than the hydrostatic annulus pressure at the same point. Any deviation must be approved through the QUEST exemption process (SLB-QHSE-S010).

## 5.5 Hydraulic Controls and Injection Systems

### 5.5.1 Fittings

Please refer to Section 4.4.12: Fittings for information on fittings.

### 5.5.2 Flexible Lines

#### 5.5.2.1 Utility Supply Hoses

All utility supply (Air & Water) hoses, or any other hoses which are rated at 285 psi or below, used on Subsea jobs shall comply with POM section Appendix B.6: Low Pressure Flexible Hoses.

#### 5.5.2.2 Umbilicals and Injection Lines

Assembled lines (hoses and end connections) used in Subsea activities for hydraulic control and chemical injection shall generally conform to the requirements of POM section Appendix B.7: Medium and High Pressure Flexible Hoses and Liners except for the Annual Survey pressure test being to a value of 1.1 * WP instead of 1.5 * WP, and not all hoses currently in the field will necessarily have been supplied with a COC. Specifically hoses used in Subsea activities must conform to the following minimum specifications:

1. Hose material according to SAE codes for the appropriate fluids: synthetic oil, mineral oils, water-based control fluids or methanol/glycol injection fluids.
2. Design Safety Factor in accordance with burst pressure = 4 x Working Pressure up to 12,500 psi ratings and burst pressure = 3.5 working pressure for pressures above 12,500 psi.
3. End fittings shall be stainless steel machined in a single piece (no cast fittings allowed for Subsea applications) or assembled with threads. No braised connections are allowed.
4. Each individual hose section shall be identified showing as a minimum the manufacturers part number and the Working Pressure.
5. A minimum collapse pressure rating must be specified for applications where the external pressure might collapse the hose or liner.
6. PVDF lined hoses are rated to a maximum temperature of 250 degF [120 degC]. Nylon 11 lined hoses are rated 160 degF [75 degC] for intermittent use and 120 degF [50 degC] for continuous use.
7. Each length of hose shall be flushed in order to get a cleanliness level corresponding to the type of utilization of the hose, reference operational manuals for correct procedure. Each end shall be plugged off by a stainless steel plug rated to same working pressure as the hose after flushing.
8. Each length of hose shall be pressure tested at original manufacturer to TP = 1.5 x WP and regularly tested to 1.1 x WP during surveys. Any leakage, damage or deformation of the hose assembly shall be cause for rejection/disposal. Reference operational manuals for testing procedure for any specific equipment.
9. Hoses shall be stored in a dark place when not in use. Never under any circumstances bend the hose below the minimum diameter of curvature (bending diameter) specified by the manufacturers.
10. Chemical injection points into the string shall be equipped with dual redundant inline check valves.
11. Re-swaging of hoses shall only be performed by trained personnel.

## 5.5.3 Rigid Hydraulic Lines

Rigid Hydraulic Lines are typically used below the Wellhead for chemical injection. Stainless 316, Inconel 625, Inconel 825 or Super Duplex 2507 seamless tubing is recommended for all rigid tubing applications. For applications with welded end fittings, all of the materials listed in this section are acceptable. The stress in the tubing must comply with ASME B31.3.

## 5.5.4 O'ring Seals

O'ring seals are essential components of all pressure-containing tools. Subsea products have several dynamic O'ring seals using back-up rings, designed to very tight tolerances.

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**Quality Note**

Only O'rings, back-up and anti-extrusion rings qualified by Schlumberger Testing Services Technological Centers for Subsea product applications shall be purchased for field use. No substitute shall be used at anytime.

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Also refer to the Downhole Testing Seal Selection Guidelines which are given in the document SH607414, attached to In Touch Content ID 3012741, the 15,000 psi PCT-F Field Operation Manual.

O'ring compounds deteriorate in the presence of ultraviolet light (sunlight), ozone, radiation, heat and moisture. O'rings must be stored in airtight opaque bags, in cool (less than 120 degF [48.88 degC]), dry locations.

The discard (ie disposal) date for a packet of unused O-rings should be printed on the packet label by the manufacturer. This date refers to a packet which remains sealed, and once the packet is opened the O-Rings must be used as soon as possible. The discard date printed on the packet will generally follow the schedule given in the table in section 2.5.7: Shelf Life of Elastomer O-Ring Seals and in any case must always be observed. Limits for the maximum shelf life of O-Rings which are stored in open packets is also given in Table 2-3: Shelf Life of Elastomer O-Ring Seals.

## 5.5.5 Hydraulic Accumulators (Control Pods)

Pre-charging the hydraulic accumulators with nitrogen must be done strictly in compliance with the operating manual of the equipment. All safety instructions must be followed.

The composition of the nitrogen must be checked for the oxygen content with a calibrated oxygen analyzer, which must be below 0.5%.

After the operation or tests and for shipping of the equipment, the nitrogen pressure must be bled off or to a specified safe level as indicated in the tool's service manual. Check with local transportation regulations for pressurized containers.

In the United States, the transportation regulation is stated, per 49 CFR Part 173.306 Section F, Item (1).

> *Accumulators installed in assembled machinery and designed and fabricated with a burst pressure of not less than five times their charged pressure at 70 degF [21.11 degC] when shipped are not subject to the requirements of this subchapter.*

Meaning, if the accumulators are charged to less than 20% of burst pressure rating, the accumulators can be shipped without bleeding off or completely bled off. Additional information is available via InTouchSupport.com.

### 5.5.6 Hydraulic Control Fluid

Water based control fluids:

- Castrol Transaqua HT (TA-HT).
- Castrol Transaqua EE1 (TA-EE-1).

Oil based control fluids:

- Brayco Micronic 864HT/200.
- Brayco Micronic SV/200.

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**Tip**

Contact SRC Subsea Engineering via InTouchSupport.com for specific job applications.

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## 5.6 Tool Joints and Crossovers

The top and bottom connections of each tool shall be defined. The specification shall include the thread description, weight, tensile strength, and working pressure. The recommended make up torque for tool assemblies should be defined at the time of tool design and documented in the operating and maintenance manuals.

Crossovers must have an equal or better specification than the string components to which they will be made up, and must be purchased either directly from a Schlumberger Product Centre or through the Regional Manufacturing process described in Appendix C by means of an RFQ.

The threads of tool joints or crossovers may be redressed (or chased) locally by an approved vendor without contacting a product centre.

**Note**

Redressing is limited to smoothing of the existing thread surfaces without altering the profile or pitch of the original thread.

However, any remanufacturing or re-cut of the threads on a tool joint, or crossover may only be performed after being given authorization through the RFQ process. The work must be performed either by the product centre responsible for the design of the tool or under the Local Manufacturing, Repair and Procurement process described in Appendix C.

# 5.7 Wellsite Pressure Testing

SenTREE retainer valves, lubricator valves and ancillary equipment are offshore safety devices. As such, utmost care must be taken with their functional testing and pressure integrity.

Whenever Subsea equipment is used at the wellsite, it shall be operationally tested (FIT) and pressure tested, before running in the hole. It is forbidden to route well flow through any section of subsurface safety testing equipment, which has not been function and pressure tested.

## 5.7.1 Basic Wellsite Pressure Test Rules

1. All pressure-containing and pressure-controlling components of the Subsea safety testing equipment used shall have a WP rating. All components to be used shall have a current Major Survey, current Annual Survey including a hydrostatic test to Test Pressure (TP) equal to 1.1 WP or WP for 5CT equipment, and have had an operational check since the date of the most recent annual survey. Equipment not complying with these conditions shall not be used.

2. Unless covered by an exemption, the Wellsite Pressure Test shall be performed at a minimum of 1.2 times the Maximum Potential Pressure (MPP) but must never exceed either the Schlumberger equipment WP rating or the WP rating of the lowest rated tool or string component.

   The Maximum Allowable Operating Pressure (MAOP) on any given job is the pressure at which the Wellsite Pressure Test was performed. Under no circumstances should the equipment be exposed to well fluid or dynamic pressures higher than the MAOP.

   The following protocol must always be respected: MAOP = Wellsite Pressure Test value = 1.2 MPP (Unless covered by exemption) ≤ WP @ current tensile load for the weakest component in the string at the time of the pressure test. If the MAOP is found to be insufficient, it can be increased, subject to the conditions in Section being met, by performing a new wellsite pressure test at a higher pressure.
   In some cases, the string must be first landed out prior to conducting pressure test operations.

   A graphic explaining the relationships between Equipment WP, the Wellsite Pressure Test, and exemption requirements is shown in section 4.5.1: Basic Wellsite Pressure Test (WPT).

   Pressure testing should be carried out with a non-volatile, non-compressible, non-flammable fluid. Water with a suitable inhibitor is recommended. If hydrate formation is likely, a mixture of ethylene glycol and water or methanol and water is recommended.

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**Caution**

Potential Severity: Light
Potential Loss: Personnel
Hazard Category: Pressure

Only use inhibitors at recommended concentrations.

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3. If an integrity test with inert gas (nitrogen or helium) is required, refer to guidelines established in Section 1.9.3: Pressure Testing with Inert Gas: (Gas Test).

4. Pressure testing with diesel shall be avoided except for special circumstances, which shall be planned for and approved through the QUEST exemption process (Standard SLB-QHSE-S010). The initial risk must be high and a HARC must be completed.

   The following guidelines should be applied:
   - Keep all ignition sources away from the pressure test area.
   - Tighten all connections before applying pressure.

- Purge all equipment with nitrogen before filling with diesel. If nitrogen is not available, ensure that all air is allowed to escape before pressuring-up above 500 psi.
- Use a low-volume pump to pressurize the diesel, maintain the rate of pressure increase below 2000 psi per min.
- When pressure testing with the assembly in the hole, it is recommended to have the diesel-water interface below the Sentree or EZ Valve, or at a level below the rig floor if the subsea valves have not been run. This will minimize the risk of a direct diesel to air contact.

5. Should a leak occur, bleed off all pressure before any attempt at repairs. The complete pressure test procedure should be repeated after repairs.
6. Do not pressure test if the ambient temperature is less than -4°F [-20°C].
7. The Schlumberger wellsite supervisor must be present during all wellsite pressure tests.
8. Detailed procedures for wellsite pressure testing are to be found in maintenance manuals or field operations manuals.

# 5.8 Special Operations

## 5.8.1 $H_2S$ Operations

The following additional rules apply to operations where $H_2S$ is expected or suspected:

1. $H_2S$ equipment shall be used according to NACE rules whenever $H_2S$ partial pressure exceeds 0.05 psi. The $H_2S$ rated equipment shall be used on all wells having the potential to produce $H_2S$ in unknown concentrations. (Refer to Appendix D). Table 5-2: $H_2S$ Equipment Limits is to be used to determine if $H_2S$-rated equipment is required for an operation.

**Table 5-2: $H_2S$ Equipment Limits**

| **Concentration of $H_2S$ (ppm)** | Unknown | $H_2S \le 770$ | $770 < H_2S \le H_2S \le 150{,}000$ | $H_2S > 150{,}000$ |
|---|---|---|---|---|
| **Equipment Service** | $H_2S$ Equipment | $H_2S$ Equipment if PP > 0.05 or Job > 24 hr | $H_2S$ Equipment if WHP > 65 psi or Job > 24 hr | $H_2S$ Equipment |

**Note**

$H_2S$ Partial Pressure (PP) = Total Pressure (**) (psia) x $H_2S$ concentration (ppm) x $10^{-6}$.

(**) Total Pressure is the maximum pressure the equipment will be subject to, it will be WHP for surface equipment or maximum anticipated internal pressure at the tool level for downhole sampling, DST or Subsea equipment.

2. On any job in which the presence of $H_2S$ is expected, operating safety rules are to be followed. These rules can be found in the SLB-QHSE $H_2S$ manual InTouch Content ID 4082472. All personnel must be $H_2S$ certified and $H_2S$ monitoring equipment must be installed and operative.
3. All $H_2S$-rated subsurface equipment must conform to NACE MR -0175.
4. Any piece of equipment, which cannot be positively identified as $H_2S$-rated, shall be considered not suitable for $H_2S$ service.
5. Repairs and modifications to $H_2S$-rated equipment can be carried out only in approved and qualified shops (approved by a Schlumberger Technology Center).
6. Viton (or other suitable fluorocarbon elastomers or perfluoro-elastomers) O-ring seals shall be used to replace Nitrile for all connections exposed to well fluids containing $H_2S$.

## 5.8.2 Cold Weather/Arctic Operations

Subsea safety equipment deployed in the well will not normally be operated at temperatures below the freezing point. Special precautions are nevertheless necessary in Cold/Arctic environments.

1. Tools are function-tested on the floor. If the lubricant used on O-rings and/or packing has frozen, permanent damage can result when function-testing. To avoid this, the tools shall be stored in a nonfreezing environment and taken out on the rig floor at the last minute. All water used for pressure testing should contain antifreeze inhibitor in suitable proportions.
2. Only pre-mixed fluid shall be used. The control console shall be protected from the environment and a heating system (e.g., steam hose) shall be available. All hoses shall be checked by flushing through with control fluid to ascertain that it has kept its antifreeze properties.

# 5.9 Safety Certification, Shop Maintenance and Quality Control

General policy and guidelines for Quality Control of Pressure-Containing Equipment are in Section 2: Equipment Quality Control and Administration.

## 5.9.1 Quality File

Each Subsea Safety Equipment assembly shall have a Quality File (as described in Sections 1.10.1: Quality File and 2.3.1: Asset Certification and Traceability).

## 5.9.2 Certification by Manufacturer and Certification Agencies

The manufacturer shall certify all pressure-containing or pressure-controlling Subsea Equipment at the time of manufacture. All subsea pressure containing or controlling equipment shall have a design approval certificate (IRC, DVR, or TA) and a COC issued by a recognized third party certifying agency. All other Subsea equipment must have a COC from an approved vendor. The manufacturer must retain original of certificates for a period of five years and duplicate originals filed in the Location's Quality File for the equipment set. Locations should retain certification documents throughout the useful life of the asset.

"Duplicate originals" are copies stamped "Certified true copy of the original", signed and dated by the responsible manufacturer quality department officer. Local regulations (e.g., NPD regulations in Norway) may possibly dictate stricter certification requirements.

## 5.9.3 Five Year Major Survey

A detailed survey and performance verification conducted by or under the control of a certification agency. All pressure containing subsea testing equipment shall undergo a major survey every five years. This includes, as a minimum, a visual inspection to check general physical condition, nondestructive examination tests and body hydrostatic and functional pressure tests, witnessed and certified by a certification agency. Refer to individual equipment manuals for detailed procedures.

Procedures for these tests are regulated by API 6A code and are detailed in document 100282338, which is included in the operations and maintenance manuals.

Local requirements might dictate more frequent re-certification surveys of some or all components of subsurface testing equipment sets.

## 5.9.4 Routine Inspection and Pressure Testing

### 5.9.4.1 FIT Checks

Pressure test and function test before every job; test pressure to be defined by job parameters. Refer to individual tool operating manual for procedures.

### 5.9.4.2 TRIM Checks

Complete tool rebuild, pressure and function test. The frequency and test pressure is defined in the equipment manual and RITE. Refer to individual tool operating manual for procedures.

All Schlumberger Testing Services owned Sentree Equipment must be initially qualified by a TRIM check and a pressure test to WP at reception.

### 5.9.4.3 Annual Survey/Q-check

The time between Annual Surveys shall not exceed 12 months. The Annual Survey checks shall be recorded in the Quality File and RITE database. Detailed Annual Surveys and TRIM check instructions are contained in the maintenance manuals. After inspection and re-assembly, the equipment shall undergo a hydrostatic pressure test and an operating test.

The hydrostatic body test shall be conducted at Test Pressure (TP) with all valves opened.

Pressure testing of closed valves shall be conducted at rated Working Pressure (WP). General pressure test procedures are as follows:

- Hydrostatic pressure tests shall be carried out exclusively in specially designed pressure test bays by qualified personnel only. It is acceptable to subcontract routine testing to reputable contractors.
- All accessories and crossovers, etc., shall also be tested during the body test. Test plugs with a pressure rating equal to or higher than the equipment being tested must be used.

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**Danger**

Potential Severity: Catastrophic
Potential Loss: Assets
Hazard Category: Pressure

Verify the WP of any accessories and crossovers attached to the tool prior to performing the body test.

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- Body pressure tests should be performed with a nonvolatile, nonflammable, low compressibility liquid such as water with a suitable corrosion inhibitor.
- All air must be bled from the system.
- Test pressure must held for a minimum of 3 min after the pressure has stabilized at TP value and the equipment and pressure gauges have been isolated from the source of pressure.
- Test pressure is bled to 0 psi.
- Test pressure is reintroduced and held for a minimum of 15 min.
- Test pressure is bled to 0 psi again.
- After the hydrostatic body test, all equipment with moving parts shall be operationally tested again at rated working pressure.
- Each bi-directional valve seat must be tested from both sides at rated working pressure, with one side open to the atmosphere.
- The operating test shall include an air test of the ball valve and flapper valve at 100 to 150 psi air pressure. Maximum acceptable leakage with air pressure above 100 psi shall be 1.25 scf/min. Valves must be free of diesel and hydrocarbons prior to conducting the air test.
- Hydraulic control consoles, chemical injection systems shall also be tested to their relevant Test Pressure (TP) including fittings, hose bundles, liners and check valves. Follow the procedures set forth in the maintenance manuals, including a response time check.
- Nitrogen purity must be checked in each bottle before it is used. The safe upper limit of oxygen concentration is 0.5%.
- If an integrity test with inert gas (nitrogen or helium) is required, the equipment must be tested first with liquid at 1.2 times the gas test pressure. In any case, Working Pressure must not be exceeded. Gas tests have an inherent higher level of risk and safety precautions must be increased accordingly. Pressure testing with a compressible fluid is not recommended. It has been proven that the benefits from gas pressure testing are not justified with regards to the potential hazards from the compressed gas and the required safety precautions. Pressure testing with gas is not allowed outside a fit for purpose pressure test bay.

**Note**

When gas pressure testing, the volume of gas should be reduced by utilizing filler bars.

## 5.9.5 Major Repairs/Remanufacture

Local field maintenance and repairs of pressure-containing or pressure-controlling Subsea Safety Equipment shall be limited to replacement of expendable parts or one-to-one replacement of subassemblies. Replacement components and assemblies must have similar or higher level of certification than the items they replace. It is recommended that a quality plan be prepared for all major repairs.

Any machining or welding repairs (called remanufacturing in API documents) shall be carried out exclusively by the manufacturer, by vendors approved by the manufacturer or in approved refurbishment centers. Welding must comply with ASME/NACE/API specifications as applicable. Repaired equipment must be certified following the guidelines for newly manufactured equipment in Section 5.9.2: Certification by Manufacturer and Certification Agencies. Non-certifiable equipment shall not be repaired and shall be junked.

The Schlumberger Technology Center responsible for the design of the equipment must sanction all major weld repairs on pressure containing parts and parts under high stress during normal operation.

When structural parts which are of a pressure retaining or load bearing nature (For example housings, bodies, etc.) are repaired or replaced the asset loses its certification status and shall require witnessed testing by a certifying agency. This re-certification includes post-repair witness of the proof pressure test along with other functional and operational tests typically found in the asset FAT procedure.

This applies to all parts whether supplied from a Schlumberger Technology centre or direct from an approved third party vendor. It is the responsibility of the location to ensure documentation relating to replacement parts are supplied with those parts as this process is not automatic.

All documentation relating to the replacement parts, including material traceability documents, should be filed in the equipment Quality file, and details of the replacement parts must be included in a RITE Work Order as described in POM section 1.10.3: Traceability.

### 5.9.6 Equipment Identification

Each individual subassembly of Subsea safety testing equipment shall be identified with the following information:

- Manufacturer's identification code and/or Schlumberger file code
- Serial number/fixed asset number
- Working Pressure rating
- Service type: $H_2S$
- Minimum design temperature and maximum operating temperature (optional).

The identification shall be dot-stamped on a non-critical area of its body.

All pressure containing or controling equipment, including crossovers, must have a serial number created and marked by the Technology centre or manufacturer. Schlumberger Field Locations shall add a unique identification number for any non pressure containing or controlling items not already marked with a serial number.

## 5.10 Subsea Equipment Procurement Guidelines

### 5.10.1 Newly Purchased Equipment

Standard equipment approved for purchasing is listed in the InTime catalog. Requests for any non-standard, special or purpose built equipment, crossovers, slick joints, injection subs, or adapters and connections must be submitted to Rapid response via OneCAT. Direct purchase of tools or equipment to be used in the landing string from third pary manufacturers is forbidden.

Minimum requirements shall be as follows:

- Equipment shall be suitable for $H_2S$ service, MDT -20°F [-29°C]. Maximum operating temperature will be specified in maintenance and service manuals.
- Material should be AISI 4130 or AISI 4140 low alloy steel, 18-22 HRC or higher grade metal meeting NACE MR-0175 as dictated by design yield strength requirements.

**Note**

Non-NACE job specific components such as crossovers, spacer subs, shear subs and slick joints must be approved following the exemption process with the initial risk being High, before placing an order.

Equipment shall have a complete engineering file and be delivered with a Quality File, including design approval and COC certifications.

### 5.10.2 Rented Equipment

Due to the primary safety function of Subsea safety equipment, renting or operating equipment supplied by a third party is not recommended. If unavoidable, Subsea testing equipment accessories may be rented from a rental agency if the policy in Section 2.3.2: Rented Equipment is respected.

### 5.10.3 Equipment not owned or supplied by Schlumberger

Any equipment which is owned or rented by the client, or supplied by another service company who have been directly contracted by the client, and which is to be included in the landing string must conform to the requirements of POM sections 2.3.3: Client Supplied Equipment, 2.3.4: Non Schlumberger Contracted Service Company Equipment and 5.10.2: Rented Equipment. A review of the equipment documentation shall be made by the SLSS Supervisor to ensure compliance and compatabillity with Schlumberger Testing Services equipment standards. Any non-compliances must be dealth with as described in section 2.3.4: Non Schlumberger Contracted Service Company Equipment.

### 5.10.4 Approval of Existing Equipment

Only equipment with a complete Quality File, with a valid major survey within the last five years and valid annual surveys are to be considered for field use.

Crossovers or other pressure containing and load bearing adapters must have a Quality File and the appropriate updated certification validation checks.

## 5.11 Crew Certification

Exclusively pressure-qualified crews shall perform all well testing and pressure testing operations.

A wellsite crew shall be considered qualified if the supervisor and at least 50% of the other crew members hold a valid certification. On multidiscipline crews, at least one operating technician or engineer per discipline must be certified. Crew members not holding a valid certification must be qualified by having completed at a minimum Intermediate Level 1 training (i.e., certification may be pending satisfactory completion of the theoretical quiz, technical training and practical jobs or tasks under supervision). Subsea pressure certification details are provided in Section 9: Testing Services Personnel Qualification and Administration.

In addition to the above, operators must be $H_2S$ certified as per the $H_2S$ manual for any operation where $H_2S$ is expected.

## 5.12 Section 5 Revision History

For more details see Appendix F.

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**Warning**
Potential Severity: Serious
Potential Loss: Security
Hazard Category: Human

The controlled source document of this manual is stored in the InTouch Content ID 3045666. Any paper version of this standard is uncontrolled and should be compared with the source document at time of use to ensure it is up to date.

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# Downhole Equipment

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# 6 Downhole Equipment

This section covers guidelines pertaining to the use of downhole equipment used in Testing Services. All Schlumberger operated equipment used for containing and controlling well pressure and flow from below the wellhead, BOP stack or Subsea equipment is covered in this definition.

The equipment referred to in this section falls into Category 3.

Downhole Sample chambers (Category 0) are covered in Section 6.

## 6.1 Overview

All downhole equipment shall be pressure rated (WP). Since the equipment is subjected to different outside and inside pressure, the rating must be specified as collapse, absolute, burst or differential.

It is forbidden to submit any piece of downhole equipment to a pressure higher than its rating during operations.

Downhole equipment will also have tensile and torsion ratings. This is normally expressed as maximum allowable tensile and torque load at minimum yield stress without internal or external pressure.

In a system assembled of different components, the WP of the weakest component gives the overall Working Pressure rating of the system. To define the effective maximum allowable pressure, one has to consider the function and position in the string of each tool and whether it contains atmospheric pressure or nitrogen-charged chambers. Each piece of equipment shall have a defined operating envelope that considers combined stresses from pressure, tension and torque.

Schlumberger ratings are defined taking into account the effect of the operating environment. Therefore, Schlumberger might assign a lower rating than the manufacturer to meet more stringent requirements. In all cases, the Schlumberger assigned pressure and tensile rating shall be used.

### 6.1.1 Test Pressure

Test Pressure for downhole equipment is usually equal to Working Pressure, as size constraints do not allow the use of large safety factors.

Integrity tests with an inert gas shall be preceded by a hydrostatic test of 1.2 x the test pressure, even in controlled conditions.

### 6.1.2 Service Type

DST equipment is suitable for $H_2S$ service and complies with NACE MR-0175 guidelines.

## 6.2 Standards and Specifications

### 6.2.1 General Standards

There are a few industry standards to downhole equipment. Some of the relevant codes that are used as reference documents in design are API Specifications 5CT and 5D for tubulars and API Specifications 14A/14D for subsurface safety valves.

### 6.2.2 General Specifications

Category 3 equipment supplied by Schlumberger Technology Centers generally conforms to the specifications described in the following subparagraphs. Always refer to the appropriate tool manual for confirmation of actual specifications.

#### 6.2.2.1 Design Safety Factors for Downhole Equipment

Due to the fact that the tool OD is limited by the well construction and that the ID must be as large as possible, the available metal thickness is limited. The design safety factors vary from 1.1 to 1.5. At safety factors approaching 1.1, ratings shall be valid at maximum rated temperature.

**Method of calculation for stresses:** No yielding of the material is permissible. Using thick wall theory (WT/R > 0.1), the maximum stress for any cross-section occurs at the inner fiber of the cylinder. For higher pressure-rated equipment in which the factor of safety approaches 1.1, maximum stresses are determined according to the Von Mises method. Simplified stress calculating models are acceptable for lower pressure rated equipment in which the factor of safety approaches 1.5.

Completion tubulars defined under API 5CT have a safety factor of 1.0.

Downhole equipment is subjected to combined loadings. Application design safety factors are generally used to manage the combined stresses. These safety factors should not be confused with equipment design safety factors as described here and are often presented as an operating envelope.

### 6.2.2.2 Pressure Rating

Pressure ratings are specified as differential (WP), collapse (annulus) and burst (tubing). Pressure rating is affected by tensile and torsion loads and the operating envelope must be considered in equipment selection. Absolute pressure affects equipment with air and nitrogen chambers and may be the limiting factor on equipment selection.

All Drill Stem Testing equipment shall have a minimum pressure rating (WP) of 10,000 psi with the exception of PIPK-DJ which has a lower Working Pressure (refer to the PIPK-DJ documentation).

### 6.2.2.3 Maximum Operating Temperature

Under standard conditions, the limiting factor with respect to operating temperature is elastomer selection. The type of operation defines the temperature rating of downhole equipment.

The temperature rating of DST, TCP equipment is a function of time and exposure. Refer to maintenance manuals and the Seal Selection Guidelines which are given in the document SH607414, attached to In Touch Content ID 3012741, the 15,000 psi PCT-F Field Operation Manual for detailed information.

### 6.2.2.4 Tool Joints and Crossovers

The top and bottom connections of each tool shall be defined. The specification shall include the thread description, weight, tensile strength, and working pressure. The recommended make up torque for tool assemblies should be defined at the time of tool design and documented in the operating and maintenance manuals.

Crossovers must have an equal or better specification than the string components to which they will be made up, and must be purchased either directly from a Schlumberger Product Centre or through the Regional Manufacturing process described in Appendix C by means of an RFQ.

The threads of tool joints or crossovers may be redressed (or chased) locally by an approved vendor without contacting a product centre.

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**Note**

Redressing is limited to smoothing of the existing thread surfaces without altering the profile or pitch of the original thread.

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However, any remanufacturing or re-cut of the threads on a tool joint, or crossover may only be performed after being given authorization through the RFQ process. The work must be performed either by the product centre responsible for the design of the tool or under the Local Manufacturing, Repair and Procurement process described in Appendix C.

### *6.2.2.5* Tensile and Torsional Strength

Tensile and torsional strength ratings are normally given at minimum yield stress. The tensile and torsional ratings of downhole equipment are calculated assuming no applied pressure loading. This is because maximum torsional load is usually seen at surface during makeup and maximum tensile load is usually seen during installation, retrieval, jarring or fishing. Tensile strength of equipment with atmospheric chambers is calculated assuming the hydrostatic pressure equals the Working Pressure (WP). Refer to equipment manuals for individual tool ratings.

## *6.2.3* Job Design and Well Integrity

Maintaining the integrity of a well is paramount in delivering a safe, high quality, service to our clients. In addition to following all the measures required to maintain the integrity of individual tools (such as maintenance, certification and traceability of critical parts), at the wellsite the overall Well Barrier Envelope must be established and maintained, and in order to do this all jobs performed with DST tools must be designed and planned in accordance with POM section 3.2: Job Design, and Planning Well Barriers. The roles and responsibilities of each member of the crew must also be assigned, and this must take into consideration their levels of training and competence.

# 6.3 Downhole Equipment General Rules

A test of at least one pressure barrier must be conducted in the well prior to any lifting or flowing the well.

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**Note**

Annular preventers are not considered as well barriers.

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A fluid is considered a barrier if the hydrostatic head of the fluid is greater than reservoir pressure and the height of the column can be monitored, with a reserve of fluid available for immediate use should it be required in order to maintain the height of the column. A job or project specific Hazard Analysis and Risk Control should be performed to identify and mitigate risks, particularly the risks associated with barriers for the annulus and the tubular wellbore.

## 6.3.1 Lifting Subs and Handling Equipment

Only certified lifting subs manufactured by Testing Services Technology Center or by approved vendors shall be used.

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**Note**

The use of lifting subs of unknown rating and origin is forbidden.

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All lifting subs or end caps must have a hole in the center to prevent them from being used for pressure testing except when specifically designed for that purpose.

## 6.3.2 Pressure Barriers for Drill Stem Testing

The recommended setup of a test string shall be according to Table 6-1: Number of Valves versus Well Parameters. These recommendations represent the Testing Services assessment of the minimum requirements deemed necessary for safe pressure operations.

Above 12 kpsi expected wellhead pressure, a production string with a production packer is recommended.

Above 15 kpsi wellhead pressure, a nippled-up wellhead shall be used.

**Table 6-1: Number of Valves versus Well Parameters**

| Flowrate and/or Shut-in Wellhead Pressure (psi) | Nature of Fluid | | | |
|---|---|---|---|---|
| | **Oil** | **Gas** | **Oil $H_2S$** | **Gas $H_2S$** |
| High Flow Rate Gas ≥ 30 MMSCF/D Liquid ≥ 8000 bpd | $S_2$ + ESD | $S_3$ + ESD | | |
| | $SS_1$ | $SS_1$ | | |
| | $D_1$ | $D_2$ | | |
| < 3000 | $S_2$ | | $S_2$ + ESD | |
| | $SS_0$ | | $SS_0$ | |
| | $D_1$ | | $D_2$ | |
| 3000 < < 5000 | $S_2$ | | $S_2$ + ESD | |
| | $SS_0$ | | $SS_1$ | |
| | $D_1$ | | $D_2$ | |
| 5000 < < 10,000 | $S_2$ + ESD | $S_3$ + ESD | | |
| | $SS_1$ | $SS_1$ | | |
| | $D_1$ | $D_2$ | | |
| 10,000 < < 15,000 | $S_3$ + ESD | | | |
| | $SS_1$ | | | |
| | $D_2$ | | | |
| > 15,000 | Production String Mandatory | | | |
| | $S_3$ + ESD | | | |
| | SCSSV | | | |
| | $D_0$ | | | |
| Legend | $S_2$ = Master Valve + Flowline Valve | | | |
| | $S_3$ = Master Valve + Flowline Valve + Surface Safety Valve (SSV) | | | |
| | $SS_o$ = Subsurface Valve (EZ valve, SCSSV, etc..) not mandatory (except for floating rigs where a SubSurface Test Tree is needed). | | | |
| | $SS_1$ = E-Z Valve or Subsea Tree or SCSSV. | | | |
| | $D_1$ = DST Valve | | | |
| | $D_2$ * = DST Valve + DST Safety Valve | | | |
| | $D_0$ = Downhole Valve not mandatory with production string | | | |
| | High Flow Rate = flow rate ≥ 30 MMSCF/D gas and/or ≥ 8000 bpd liquid | | | |
| | The above valve configurations are understood as a minimum recommended setup and may be upgraded at customer's discretion. | | | |

* Exception to this recommendation is acceptable for:

1. Ultra HPHT operations using the “J” string, due to the single shot nature of these tools. There is a high reliability of single shot tools and the importance of keeping the string as simple as possible justifies this exception.
2. Large Bore strings where a large bore DST safety valve does not exist. In this case an E-Z Valve or Subsea Tree or SCSSV is strongly recommended for all wells where it is not already mandatory in the above table and a HARC must be developed to mitigate any safety concerns.
3. If WHP < 3,000 psi and there is an E-Z Valve or Subsea Tree or SCSSV in the string, then the requirement is relaxed to D1 only.

The Subsea Tree, E-Z Valve and SCSSV are safety valves and shall not be used as lubricator valves.

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**Note**

The advantage of the HiPAck (HPPK) is that it is single trip set and release alternative to permanent packers. A key feature of the HiPAck is the Below Packer Circulating Valve (BPCV), however this is not compatible with a DST safety valve such as a PFSV as it will be impossible to reverse through the BPCV once the PFSV is activated.

If the BPCV function is not going to be used, then the HPPK should be run with a blank BPCV sub.

However, if the job design requires the use of the BPCV feature, and the well conditions require the use of a DST safety valve (ie D2 in the table above), then a HARC shall be performed and an exemption raised in QUEST following the process in OSF-QHSE Standard #10 with approval at Area level for the removal of the safety valve from the string.

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A summary table of selection of equipment based on WP rating, and a graphic explaining the relationships between Equipment WP, the Wellsite Pressure Test, and the exemption requirements is shown at the end of section .

## 6.3.3 Fittings

Please refer to Section 4.4.12: Fittings for information on fittings.

### 6.3.4 O'Rings, Seals and Elastomers

Seals are essential components of all downhole tools. The elastomer compounds qualified by Testing Services Technology Centers are specifically designed for the oil industry and are compatible with normal well fluids. They have special resistance to attack by refined chemicals and gas invasion. Environmental Quality testing with specific elastomers and seals validates the rating of any downhole equipment.

Only seals, back-up and anti-extrusion rings qualified and specified by Testing Services Technology Center shall be purchased for field use. No substitute shall be used at anytime.

Refer to the Downhole Testing Seal Selection Guidelines which are given in the document SH607414, attached to In Touch Content ID 3012741, the 15,000 psi PCT-F Field Operation Manual for guidelines and applications.

Elastomer compounds deteriorate in the presence of ultraviolet light (sunlight), ozone, radiation, heat and moisture. Seals must be stored in airtight opaque bags, in cool (less than 120 degF [48.88 degC]), dry locations.

The discard (ie disposal) date for a packet of unused O-rings should be printed on the packet label by the manufacturer. This date refers to a packet which remains sealed, and once the packet is opened the O-Rings must be used as soon as possible. The discard date printed on the packet will generally follow the schedule given in the table in section 2.5.7: Shelf Life of Elastomer O-Ring Seals and in any case must always be observed. Limits for the maximum shelf life of O-Rings which are stored in open packets is also given in Table 2-3: Shelf Life of Elastomer O-Ring Seals.

## 6.4 Nitrogen in Downhole Tools

Nitrogen gas is used in downhole tools to charge reference chambers. It is also used to pressure test atmospheric chambers and rupture disc ports. Due to the inherently higher level of risk when dealing with compressed gases, nitrogen shall be used exclusively in the equipment where it is specified and for no other purposes.

Tools specifically designed to hold nitrogen pressure or trap internal pressure have bleed-off ports in the joints, positioned to vent internal pressure before the last threads disengage. This is not the case for every tool joint; therefore avoiding the use of nitrogen prevents potential mishaps.

When using nitrogen, follow the precautions specified in Section 1.9.3: Pressure Testing with Inert Gas: (Gas Test) and in the relevant operations and maintenance manuals.

The purity of the nitrogen shall be below 0.5% oxygen content, measured with a calibrated oxygen analyzer.

## 6.5 Pressure Testing

There are two different scenarios in which pressure testing is done, either at surface or downhole.

Surface pressure tests require special consideration due to the exposure of personnel. It is important that any such test is done in a controlled environment with only essential personnel present.

Downhole pressure tests are a necessary part of a DST operation. Typically, such tests are used to confirm the integrity of packers or seal assemblies once they have been installed. Depending on the DST String configuration, either an annular test or a tubing test can be used. When testing a packer or seal assembly by pressurizing the annulus, it is important to keep the test pressure under any previous casing test pressure as well as under any burst pressure of the string in the hole. Detailed procedures for testing of downhole equipment is provided in the appropriate tool operating manuals and should be detailed in the completion, stimulation or test program.

Whenever downhole equipment is used, it should be pressure tested before opening communication to the well fluids. Well flow should not be routed through any section of downhole equipment which has not been pressure tested at the wellsite.

When particular logistic situations make it difficult to carry out a full pressure test of the equipment, (e.g., desert, rigless operations, limited amount of test fluid on the wellsite), the above rule may be relaxed if all the following criteria is met:

- Expected maximum shut-in wellhead pressures lower than 3000 psi.
- All equipment is pressure tested at the shop prior to departure.

For the purpose of surface tests, DST tools with 3-1/2 IF connections have a tool joint groove where an O-ring can be installed. The purpose of the O-ring in the 3-1/2 IF tool joint groove is to facilitate the surface test without torquing the test caps up to its optimum torque value. The design intent of the O-ring seal is NOT to assist in the seal of the connection during downhole conditions but it is the purpose of the metal to metal (MTM) face seal of the tool joint. Moving the “downhole seal” from the MTM face seal to the O-ring seal will change the hydraulic loading of the connection, and under high pressure situations may result in a catastrophic mechanical overload, therefore all O-rings shall be removed from the 3-1/2 IF tool joint groove before tools are run in holes.

## 6.5.1 Basic Pressure Test Rules

1. All assets used shall have a WP rating, a current Annual Survey and have had an operational check since the date of the most recent Annual Survey. Equipment not complying with these conditions shall not be used.
2. At the wellsite, the test pressure at surface shall be less than 67% of the WP of the equipment. (1.5 safety factor on max WP).

   If the customer requests a wellsite pressure test exceeding these values, special precautions must be taken and a controlled pressure testing area instituted.
3. Unless covered by an exemption, the Wellsite Pressure Test carried out once the tools are in the hole shall be performed at a minimum of 1.2 times the MPP, but must never exceed either the Schlumberger equipment WP rating or the WP rating of the lowest rated tool or string component.

   The Maximum Allowable Operating Pressure (MAOP) on any given job is the pressure at which the Wellsite Pressure Test was performed. Under no circumstances should the equipment be exposed to well fluid or dynamic pressures higher than the MAOP.

   The following protocol must always be respected: MAOP = Wellsite Pressure Test value = 1.2 MPP (Unless covered by exemption) ≤ WP @ current tensile load for the weakest component in the string at the time of the pressure test.

   If the MAOP is found to be insufficient, it can be increased, subject to the conditions in section being met, by performing a new wellsite pressure test at a higher pressure.

   In some cases, the string must be first landed out in the subsea wellhead prior to conducting pressure test operations.

   A graphic explaining the relationships between Equipment WP, the Wellsite Pressure Test, and exemption requirements is shown in section 4.5.1: Basic Wellsite Pressure Test (WPT).

   Pressure testing should be carried out with a non-volatile, non-compressible, non-flammable fluid. Water with a suitable inhibitor is recommended. If hydrate formation is likely, a mixture of ethylene glycol and water or methanol and water is recommended.

Potential Severity: Light
Potential Loss: Assets
**Caution** Hazard Category: Toxic corrosive hazardous substances

Only use inhibitors at recommended concentrations.

4. If an integrity test with inert gas (nitrogen or helium) is required, the equipment must be tested first with liquid at 1.2 times the gas test pressure. Gas tests have an inherent higher level of risk and safety precautions must be increased accordingly. Pressure testing with a compressible fluid is not recommended. It has been proven that the benefits from gas pressure testing are not justified with regards to the potential hazards from the compressed gas and the required safety precautions.
5. Pressure testing with diesel shall be avoided except for special circumstances, which shall be planned for and approved in advance through the exemption process, the Management of Change and Exemption Standard (SLB-QHSE-S010). The initial risk must be high.

   The following guidelines should be applied:
   - Keep all ignition sources away from the pressure test area.
   - Tighten all connections before applying pressure.
   - Purge all equipment with nitrogen before filling with diesel. If nitrogen is not available, ensure that all air is allowed to escape before pressuring-up above 500 psi.
   - Use a low-volume pump to pressurize the diesel. Keep the rate of pressure increase below 2000 psi per minute.
   - When pressure testing with the assembly in the hole, it is recommended to have the diesel-water interface below SenTREE or EZ-Valve, or at a level below the rig floor if the subsea valve has not been run. This will minimize the risk of a direct diesel to air contact.
6. Should a leak occur, bleed off all pressure before any attempt at repairs.

   The complete pressure test procedure should be repeated after repairs.
7. Do not pressure test if the ambient temperature is less than -4°F [-20°C].
8. The Schlumberger wellsite supervisor must be present during wellsite pressure-testing.

# 6.6 Special Operations

## 6.6.1 $H_2S$ operations for DST

The following additional rules apply to operations where $H_2S$ is expected or suspected during service operations:

**Note**

$H_2S$ Partial Pressure (PP) = Total Pressure (**) (psia) x $H_2S$ concentration (ppm) x $10^{-6}$.

(**) Total Pressure is the maximum pressure the equipment will be subject to, it will be WHP for surface equipment or maximum anticipated internal pressure at the tool level for downhole sampling, DST or Subsea equipment.

1. If the $H_2S$ concentration is known and $H_2S$ partial pressure is above 0.05 psi, $H_2S$ equipment should be used. See Appendix D. $H_2S$ rated equipment shall be used on all wells having the potential to produce $H_2S$ in unknown concentrations.

   If the $H_2S$ concentration is not known, and the well has the potential to produce it, then $H_2S$ equipment MUST be used.

   The specifications for individual tools when used in an $H_2S$ environment should be checked in the tool manuals and verified in GeMS document number 100685788 (linked to the tool specification page of each manuals) during the job design phase. See also Appendix D.

   **Note**

   Tools previously having 17-4 PH material may have been retrofitted with housings and mandrels supplied with Inconel material, in these cases GeMs Document 100685788 is non applicable.

   Although not recommended, if $H_2S$ equipment cannot reasonably be made available, standard equipment can then be used, provided:

   - $H_2S$ concentration is less than 150,000 ppm.
   - Bottom hole temperature is greater than 175 degF.
   - The exposure is less than 24 hr.
   - No formation fluids are trapped and returned to surface.

- It has been at least 24 hr since the equipment was last exposed to $H_2S$.

For sampling chambers, it is imperative to use $H_2S$-rated equipment according to NACE rules, whatever the BHT. This corresponds to 10 ppm of $H_2S$ at 5000 psi and 5 ppm of $H_2S$ at 10,000 psi. No derogation shall be acceptable.

2. $H_2S$ operating safety rules in the SLB-QHSE $H_2S$ manual, which can be found in InTouch Content ID 4082472), are to be followed on any job where presence of $H_2S$ is expected. All personnel must be $H_2S$ certified. $H_2S$ monitoring equipment must be installed and operative.
3. All $H_2S$-rated equipment must conform to NACE MR-0175.
4. Any piece of equipment, which cannot be positively identified as $H_2S$-rated, shall be considered not suitable for $H_2S$ service.
5. Viton (or other suitable, qualified, fluorocarbon elastomers or perfluoro-elastomers) O-ring seals shall be used to replace Nitrile for all connections exposed to well fluids.
6. Cushion fluids should be suitably treated to neutralize the $H_2S$ effect on the equipment. On any $H_2S$ test where it is not planned to produce the water cushion to surface during the test, a suitable scrubbing agent should be added to the cushion to neutralize the $H_2S$ gas bubbling through.
7. Standard downhole equipment that has been exposed to $H_2S$ shall not be reused for at least 24 hr since the time the tools were last exposed. The equipment will recover faster if exposed to elevated ambient temperatures.

## 6.6.2 Nighttime Operations

Nighttime operations present additional safety and environment risks. Nonstandard circumstances related to nighttime pressure work and the lack of adequate lighting, make leak detection difficult and increases the possibility of reduced crew alertness.

The following basic recommendations apply to downhole equipment used during nighttime operations in areas where a normal day/night cycle takes place in a 24-hr period:

1. No nighttime operation shall be initiated by a crew that has had less than 8 hr of rest in the last 24 hr.
2. No first-time pressure communication from the reservoir to the wellhead (i.e., opening DST tool on a wildcat well) should be initiated after dark. Managers may agree upon exceptions to this rule with customers in advance for established production sites, whenever permanent artificial lighting is adequate.

3. Jobs with established pressure may be continued after dark provided adequate lighting is available to illuminate all possible areas where leaks could develop. All areas where remote controls are located and suitable escape paths away from the wellhead must be available. Local procedures for such jobs must be agreed on beforehand with the customer representatives and additional lighting procured as required.

   The decision to continue a particular job after dark shall be taken by the supervisor in conjunction with the customer representative based on existing lighting conditions. Only managers present on the wellsite can change the decision.

4. If it is necessary to pull a DST string after dark, the string shall be reversed out before pulling.

5. Production tests or other operations on sites with no permanent installations are normally forbidden during hours of darkness (e.g., masts, crane trucks, lift barges, etc.), except for special circumstances, which shall be planned for and approved in advance through the exemption process; the initial risk must be high.

For high-latitude operations, where daylight periods may be very short or nonexistent, a specific procedure must be established by the location, in accordance with the customer, based on the “adequate lighting” principle.

## 6.6.3 Cold Weather/Arctic Operations

Downhole equipment, being deployed in the well, will not normally be operated at temperatures below the freezing point. Special precautions are nevertheless necessary in cold/arctic environments.

1. Equipment going to arctic areas shall be tested with inhibited fluid even at the shop.

2. Tools are often function tested on the floor. If the lubricant used has frozen, permanent damage can result when function-testing. Tools should be stored at temperatures above freezing and deployed only at the last minute before making-up.

3. Particular care shall be taken with all downhole components when handling at surface. Tool bodies will be brittle when the temperature drops below -20°F [-30°C]. Pressure testing cannot be performed unless special materials are used.

# 6.7 Asset Certification, Maintenance and Quality Control

General guidelines for quality control of pressure-containing equipment are in Section 2: Equipment Quality Control and Administration.

## 6.7.1 Asset Quality File

There are no specific industry standards covering downhole tools and hence no general industry demands to quality assurance through a Quality File. Only sampling chambers require a design approval certificate. To ensure safe and quality assured operations, Schlumberger Testing Services has set its own standard for downhole tools. The complete design specification, material traceability, function check results and pressure test records are all kept for a 5-yr period by the Schlumberger Testing Services Technology Center.

For downhole tools, the requirement of the Quality File is modified to contain the following:

- The equipment work-order (or pick-list) that contains the part numbers, serial numbers (part traceability) and description of the parts making up the tool.
- Suppliers data book which is the Test and Inspection documentation describing the function test and pressure test record.
- Procurement and movements records (compiled by the Location)
- RITE history card (compiled by the Location)
- Reception inspection and pressure test record (compiled by the Location)
- Certification renewals as required (delivered by certification agencies)
- Major repairs documentation and certifications.
- Traceability records for replaced parts when required (compiled by the Location)
- NDE test records (delivered by the NDE contractor)

Downhole tools procured from a third party vendor should have:

- An assembly record itemizing all components by equipment code, serial number or other ID number, description, Working Pressure, Test Pressure, last qualification test
- Manufacturer's certification and traceability records for each pressure and load-bearing component.

### 6.7.2 Routine Inspection and Pressure Testing of Assets

All downhole assets must be initially qualified by an inspection and hydrostatic test at reception and verified at regular intervals according to RITE procedures as per Section 2.5: Asset Maintenance - RITE.

### 6.7.3 Major Repairs/Remanufacture

Local field maintenance and repairs of pressure-containing or pressure-controlling downhole equipment shall be limited to replacement of expendable parts or one-to-one replacement of subassemblies. Replacement components and assemblies must have similar or higher level of certification than the items they replace. It is recommended that a Quality Plan be prepared for all major repairs. Any machining or welding repairs (called “re-manufacturing” in API documents) shall be carried out exclusively by the manufacturer, by vendors approved by the manufacturer or in approved refurbishment centers. Welding must comply with ASME/NACE/API specifications as applicable. Repaired equipment must be re-certified.

### 6.7.4 Equipment Identification

Each asset, shall be identified with the following information:

- Manufacturer’s identification code and/or Schlumberger Testing Services asset code
- Serial number/fixed asset number/part number as applicable

The identification shall be dot stamped on a not-easily-damaged part of its body (e.g., a flat recess milled on a structurally non-critical part).

Schlumberger Field Locations shall add a unique identification number for items like crossovers, etc., not bearing a serial number.

## 6.8 Crew Certification

Qualified crews shall perform all pressure operations. Pressure certification details on procedures are provided in Section 9: Testing Services Personnel Qualification and Administration.

In addition to the pressure certification details discussed herein, all operating personnel must be $H_2S$-certified as per $H_2S$ manual, for any operation where $H_2S$ is expected (Hydrogen Sulfide Manual, InTouch Content ID 4082472).

Any deviation from the guidelines listed herein requires an exemption as per the Management of Change and Exemption Standard (SLB-QHSE-S010).

## 6.9 Section 6 Revision History

For more details see Appendix F.

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**Warning**
Potential Severity: Serious
Potential Loss: Security
Hazard Category: Human

The controlled source document of this manual is stored in the InTouch Content ID 3045666. Any paper version of this standard is uncontrolled and should be compared with the source document at time of use to ensure it is up to date.

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# Reservoir Sampling and Analysis Equipment

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# 7 Reservoir Sampling and Analysis Equipment

This section covers guidelines for the use of Reservoir Sampling and Analysis Pressure Equipment. All equipment used for capturing samples, both downhole and surface, are covered under this definition, as well as all well site and laboratory fluids and rock analysis equipment that holds pressure, including PVT pressure cells, core holders, piston accumulators, tri-axial/poly-axial load cells etc. Equipment is categorized based upon definitions described below.

---

**Warning**

Potential Severity: Serious
Potential Loss: Assets
Hazard Category: Pressure

Ensure correct body positioning and hand placement during any pressure operations related to fluid sampling and analysis operations. Bleedholes on pressure fittings, valve blocks, gauges etc. have the potential to eject high pressure jets of fluid (water/glycol, synthetic oil, nitrogen etc.).
These jets can inject fluid through the skin and into the soft tissues of the body. Entry point wounds may look insignificant however internal dispersal of fluids may be widespread through the body tissues.
**Immediate specialist medical attention must be sought in all cases** for specialized treatment to ensure all wounds are thoroughly treated and cleaned. If left untreated, these injuries can develop very serious medical complications.

---

### Category 0

This class of equipment covers downhole sampling chambers/tools (both Testing Services and Wireline). The equipment does not represent a risk to personnel downhole, but falls into Category 1 when brought back to surface for handling, validation, heating and transfer to a transportable sample receptacle. Safety Factors vary from 1.2 to 3.0 (e.g. SRS, SLS, SPMC, CPS, MSB, MPSR, MRSC etc.)

### Category 1.1

Surface equipment designed to handle only internal pressure (e.g. sample receptacles, Laboratory PVT cells, Core Holders, Load Cells.)

### Category 1.2

Surface equipment designed to handle full wellhead pressure and flow, from the flowhead or wellhead to the process equipment (e.g. Wellsite Sampling Module).

### Category 2.1

This is surface pressure vessels, piping equipment and pumps handling pressure and flow down stream of the wellhead equipment (e.g. Active Sampling Device).

### Category 3.2

Includes DST Equipment located below the ground level or sea bed subject to formation and well bore pressure (e.g. SCAR).

---

**Note**
This section should be used in conjunction with all other relevant sections in the Testing Services and/or Wireline Pressure Operations Manual as appropriate.

---

## 7.1 Overview

All RSA pressure containing equipment shall be pressure rated. The rating is expressed as a Working Pressure (WP) and a Test Pressure (TP).

Schlumberger Product Development normally assigns Working and Test Pressure ratings unless designed by a Schlumberger approved third party equipment manufacturer. Occasionally Product Centers will assign a lower rating to meet more stringent requirements. In all cases the Schlumberger-assigned Working Pressure rating (WP) must be used.

It is forbidden to submit any piece of RSA equipment to a differential pressure higher than its WP rating during operations.

The Working Pressure rating is valid in a given temperature range. Depending on the equipment type and its specifications, a different type of equipment shall be used for temperatures outside the range specified. If the given equipment is to be used outside the specified temperature range, the Working Pressure rating will be modified. This modification to WP shall be qualified via the Product Center.

In an assembly of different components, the WP of the weakest component at the operating temperature gives the overall Working Pressure rating of the system.

## 7.1.1 Test Pressure

The latest RITE File Code Certification and Maintenance Requirements and the Operating/Maintenance Manuals/Procedures within InTouchSupport.com must be reviewed and understood prior to commencing any pressure testing of any RSA pressure retaining equipment.

Under no circumstances should the working pressure or test pressure be exceeded whilst conducting normal operations within working pressure or recertification work to test pressure respectively.

All applicable certification requirements for all fluid sampling tools, sample bottles and receptacles **must be maintained throughout the duration of the assets lifetime** as per RITE FCC and Operating/Maintenance Manuals/Procedures. This includes all maintaining all transportation certifying authority requirements e.g. US-DOT, TC and PED etc.

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**Note**

Each transportation certifying authority (US-DOT, Transport Canada, PED etc.) has specific certification requirements that must be strictly adhered to in order to meet specific transportation regulations for the shipment of reservoir fluid samples (Dangerous Goods/HazMat) within sample bottles or sampling tools designed for this purpose. These certification requirements are over and above minimum Schlumberger Pressure Standards and Pressure Operations Manual requirements e.g. over and above the standard 5 year 3$^{rd}$ party witnessed hydrostatic test.

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**Example - US-DOT Certification Requirements**

The US Dept. of Transport (49-Code Of Federal Regulations) states that test pressure should be 1-2/3 times the WP, i.e., a bottle with 15 000 psi WP has a test pressure of 25,000 psi. In addition it should be noted that the US-DOT pressure test is a **Volumetric Expansion Test not a Hydrostatic Test**. This test also meets requirements of the Transport Canada certification requirements.

The US-DOT Volumetric Body Swell and Transport Canada Certification Tests must be conducted in a specialized US-DOT and Transport Canada approved recertification facility e.g. at Oilphase Product Center in Aberdeen (See InTouch Content ID 4264111).

**Note**

Standard Schlumberger POM compliant Test Bays do not typically meet these requirements.

**Table 7-1: Pressure Ratings of Wireline Sample Chambers**

| Description | Working Pressure (psi) | Test Pressure (psi) |
|---|---|---|
| MRSC-AB, CB, FA, HA, non $H_2S$ rated | 14 000 | 18 000 |
| MRSC-BA, BB, DA, DB, GA, JA, $H_2S$ rated | 15 000 | 18 000 |
| MRSC-BC, DC, GB, JB, PB, $H_2S$ rated | 20 000 | 24 000 |
| MRSC-EA WITH FLS-B | 10 000 | 12 000 |
| MDSU-AA $H_2S$ rated | 15 000 | 18 000 |
| RFS-AB, AE, AF, BB, BD, non $H_2S$ rated<br>RFW-AB, AC, AD, BA, BB | 20 000 | 24 000 |
| RFS-AC, AD, AE. BC, $H_2S$ rated | 15 000 | 18 000 |
| SRSC-AA, SRSW-AA $H_2S$ rated | 20 000 | 24 000 |
| SRSC-LA, BB, SRSW-LA, BB $H_2S$ rated | 15 000 | 18 000 |
| MPSR-BA | 20,000 | 33,333 |

**Note**

The standard Wireline chambers were not all designed for testing at 1.5 times their working pressure. This table details the working and test pressure for each Wireline sample chamber. InTouchSupport.com should be consulted for data for any chamber not listed in this table. Under no circumstances should the working pressure or test pressure be exceeded.

## 7.1.2 Test Pressure of Laboratory Equipment

Schlumberger laboratory analysis pressure equipment is typically designed and manufactured to one of the following code/directives: ASME Section VIII, Div 1; ASME Section VIII, Div. 2; or PED. Test pressure requirements vary among these as follows: 1.3*WP, 1.25*WP and 1.43*WP respectively; therefore, the test pressure requirement must be determined through reference to the vessel marking RITE File Code and operations manuals or for a particular asset.

**Note**

Any DBR legacy equipment, manufactured by DBR Technology Center, which is not marked with Test Pressure is now obsolete. This equipment must be removed from service, red tagged and either junked or returned to DBR for re-work.

Any TTK legacy equipment must be marked with a Working Pressure and Test Pressure.

## 7.1.3 Service Category

The Service Categories can be defined by the following parameters:

### Minimum Design Temperature:

| | | |
|---|---|---|
| Standard Temperature: | 0 degC (32 degF) | as per North Sea requirements |
| | **Or** -29 degC (-20 degF) | as per ASME (API-Specification 6A) |
| Low Temperature: | -20 degC (- 4 degF) | as per North Sea requirements |
| Arctic Conditions | < - 20 degC (< - 4 degF) | |

**Note**
The cooling effect of gas expansion at chokes and restrictions must be taken into consideration when determining the Minimum Design Temperatures of the equipment.

### Maximum Operating Temperature:

| | |
|---|---|
| Defined for each equipment: | 121 degC (250 degF) |
| | 177 degC (350 degF) standard or 200 degC (392 degF) |

### Fluid Class:

| | |
|---|---|
| $H_2S$ Service: | according to NACE MR-0175 / (ISO 15156 Parts 1, 2, 3 – Laboratory Analysis Equipment) |
| Standard Service: | also called General Service |

### PSL:

**P**roduct **S**pecification **L**evel for API-6A components.

**Note**

The allowable levels of $H_2S$ for $H_2S$ Service Laboratory Fluid Analysis equipment may be severely limited at elevated temperatures. Refer to InTouch content ID 4993534 DBR Product Limitations In Sour Environments. If the equipment is not on the list in this content, InTouch must be contacted.

Potential Severity: Light
Potential Loss: Information
**Caution** Hazard Category: Machinery equipment hand tools

All Laboratory Analysis Equipment designated for $H_2S$ Service shall comply with the current NACE MR 0175/ISO 15156 standards.

## 7.2 Standards and Specifications

The general standards and general Schlumberger specifications described below apply to all Schlumberger Sampling and Pressure Equipment. Local authorities have issued additional regulations that relate to well testing operations, such as:

- Det Norske Veritas rules for mobile offshore units Pt. 6 DRILL (N).
- UK Statutory Instruments No. 913 and HSE Guidance Notes.
- NPD regulations for drilling, etc., for petroleum in Norwegian internal waters.

### 7.2.1 General Standards

Sampling and pressure equipment used by Schlumberger shall comply with the following standards where applicable:

- API Specification 6A for downhole sampling tools and high pressure flowlines upstream of choke manifolds.
- API RP 14E and/or ASME B31.3 for "low pressure" sampling flowlines downstream of choke manifolds.
- ASME Boiler and pressure vessel code Section VIII Division 1 for pressure vessels.
- PD-5500 for pressure vessels not covered by ASME VIII.
- NACE MR-0175 / ISO 15156 for all $H_2S$ Service Equipment.
- US Federal Code 49-CFR.
- Canadian Transport Code CAN/CSA-B339-96.

- United Kingdom Carriage of Dangerous Goods and Transportable Pressure Vessel Regulations.
- Pressure Equipment Directive (PED 97/23/EC).
- Transportable Pressure Equipment Directive (TPED 99/36/EC).
- Technical Code for Refillable Transportable Pressure Receptacles for Oil Well Samples.

## 7.2.2 General RSA Specifications

Equipment supplied by Oilphase-DBR Product Center, Terratek Technology Centre and DBR Technology Center conforms to the following general specifications:

1. **High Pressure Sampling Equipment** (complying with API-Specification 6A, Category 0 and Category 1.1):

| | |
|---|---|
| Temperature range: | Refer to 7.1.3: Service Category |
| Fluid class (API 6A): | API 6A product specification level:<br>PSL2: 0 to 5 kpsi (This equipment is $H_2S$ service complying with NACE MR-0175)<br>PSL3: 5 kpsi to 15 kpsi (This equipment is $H_2S$ service complying with NACE MR-0175) |

2. **Low Pressure Sampling Equipment** (complying with ASME B31.3 and API RP 14 E, mostly Category 1.2):

| | |
|---|---|
| Temperature range: | Refer to 7.1.3: Service Category |
| Fluid class: | $H_2S$ service in compliance with NACE MR-0175 |

3. **High Pressure Sample Receptacles** (complying with API-6A and PD-5500, Category 1.1):

| | |
|---|---|
| Temperature range: | Refer to 7.1.3: Service Category |
| Fluid class: | $H_2S$ service in compliance with NACE MR-0175 |

4. **Low Pressure Sample Receptacles** (complying with BS-5045 part 3, EC 84/526, US-DOT CFR 49-DOT 3A, 3E, Category 1.1):

| | |
|---|---|
| Temperature range: | Typically up to 150 degC (300 degF) at reduced maximum working pressure |

| | |
|---|---|
| Fluid class: | $H_2S$ service in compliance with NACE MR-0175 |

**5. High Pressure Sample Carriers** (complying with API Specification 5CT and Specification 5D for Tubular, Category 3.2):

| | |
|---|---|
| Temperature range: | Typically up to 200 degC [392 degF] at reduced maximum working pressure |
| Fluid class: | $H_2S$ service in compliance with NACE MR-0175 |

**6. High Pressure Laboratory Fluids Analysis Equipment and PVT Cells** (complying with ASME Section VIII, div 1 or div 2, PED 97/23/EC, (Category 1.1):

| | |
|---|---|
| Temperature range: | Typically from -20 degC [-4 degF] up to 200 degC [392 degF] at maximum working pressure |
| Fluid class: | $H_2S$ service in compliance with NACE MR-0175/ISO 15156 standard |

**7. High Pressure Rock Analysis Equipment**
(complying with PED 97/23/EC, ASME Section VIII, div 1 or div 2, Canadian B51 Boiler Code)

| | |
|---|---|
| Temperature range: | Typically from -18 degC [0 degF] up to 150 degC [302 degF] at maximum working pressure |
| Fluid class: | N/A |

**8.** Low Pressure Rock Analysis Equipment (Core Canisters)

| | |
|---|---|
| Temperature range: | Typically from 16 degC [60 degF] up 100 degC to [212 degF] |
| Fluid class: | N/A |

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**Note**
Temperature and fluid class are equipment specific, always check equipment rating.

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## 7.2.3 General Surface Sampling Standards and Specifications

This covers surface equipment designed to handle pressure and flow (e.g., Phase Sampler, Wellsite Sampling Module, Surface Sampling Manifolds) Category 1.2 equipment.

Oilphase Product Center designed sampling systems should conform to NACE-MR01-75 as standard. Other standards, such as API-Specification 6A, are not often applicable to surface sampling equipment as they are not designated “well control equipment”. API-Specification 6A should be used as a design and manufacturing guideline wherever possible and practicable. Equipment classified as Category 1.2 should conform to ASME B31.3 and API RP14E as per section 7.2.1: General Standards.

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**Note**

Not all surface sampling equipment sets (SSK, WSK etc.) currently in the field are NACE-MR01-75. If in doubt, assume it is not suitable for $H_2S$.

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## 7.2.4 General Laboratory Fluids Analysis Standards and Specifications

Schlumberger laboratory fluid analysis pressure equipment manufactured by DBR Technology Center complies with sound engineering practice and recognized design codes. Additional requirements may be imposed through national and/or local regulatory authorities and may vary between regions. High-pressure laboratory equipment generally does not fit well into widely accepted design codes such as ASME Section VIII or BS 5500.

Historically, 1/8", 1/4" and 3/8" NPT fittings have been used on DBR Technology Center manufactured laboratory fluid analysis equipment at pressures up to 15,000 psi. The use of these and any NPT fittings at pressures greater than 10,000 psi is now forbidden. Refer to InTouch Content ID 4742940, InTouch Content ID 4889059 and InTouch Content ID 4889077 for details of equipment affected and modification recaps as applicable.

All laboratory fluids analysis equipment designs shall meet the standards listed below:

- PED 97/23/EC Pressure Equipment Directive using:
  - ASME Boiler and Pressure Vessel Code Section VIII, Division 2,
  - Particular Material Appraisal Materials.

- NACE MR –0175 / ISO 15156 Materials for use in $H_2S$ containing environments in oil and gas production.
- Canadian Standards Association B51 Boiler, Pressure Vessel and Pressure Piping Code.

Regulatory requirements for high-pressure laboratory equipment vary significantly between jurisdictions and must be evaluated prior to procurement or transfer of equipment between facilities. The responsibility to meet these requirements may lie with the manufacturer, the user or both, depending on location; therefore, the assumption should be that both the product centers and laboratories take responsibility for ensuring the regulations are identified and met. The following are code requirements that apply to Schlumberger laboratory fluid analysis equipment. This is a list for three key markets only.

## United States

### ASME Boiler and Pressure Vessel Code

Requirement in most US States. Schlumberger laboratory fluid analysis equipment is exempt from the requirements of this code except manufactured equipment specified by DBR Technology Center.

## Canada

### CSA B51 Boiler, Pressure Vessel and Pressure Piping Code.

Design audit and registration through provincial jurisdictional authority is required. A Canadian Registration Number is issued and must appear on the vessel. The scope of this code includes all pressure equipment intended for use above 15 psi that could contain a gas or expansible fluid, regardless of volume.

## European Union

### PED 97/23/EC Pressure Equipment Directive

A design examination by a notifying body such as DNV, Bureau Veritas, TUV, etc, is required. The scope of the directive includes all pressure equipment intended for use above 7 psi. The volume threshold is generally 100 cc; however, if WP is sufficiently high and the contained fluid is defined as dangerous, equipment with volumes less than 100 cc are required to meet the directive. It is mandatory that all pressure equipment entering the EU complies with the PED and is CE marked as necessary.

**Note**

Compliance with other directives such as LVD (Low Voltage Directive), MD (Machinery Directive), EMC (Electromagnetic Compatibility) is required for CE marking. All equipment manufactured by DBR-TC is CSA inspected. The user of the equipment must ensure that local regulations are satisfied in the country where it is being used. Assistance with compliance to these directives will be provided by DBR Technology Center if required.

### 7.2.5 General Rock Laboratory Equipment Standards and Specifications

The laboratory pressure equipment manufactured by TerraTek engineering group complies with sound engineering practice and recognized design codes. Additional requirements may be imposed through national and/or local regulatory authorities and may vary between regions. High-pressure laboratory equipment generally does not fit well into widely accepted design codes such as ASME Section VIII or PED 97/23/EC.

All laboratory Rock Analysis equipment designs shall meet the standards listed below, as applicable:

- PED 97/23/EC Pressure Equipment Directive.
- ASME Boiler and Pressure Vessel Code Section VIII, Division 2, and/or 3.
- Particular Material Appraisal Materials.
- NACE MR –0175 / ISO 15156 Materials for use in H2S containing environments in oil and gas production.
- Canadian Standards Association B51 Boiler, Pressure Vessel and Pressure Piping Code.Regulatory requirements for high-pressure laboratory equipment vary significantly between jurisdictions and must be evaluated prior to procurement or transfer of equipment between facilities. The responsibility to meet these requirements may lie with the manufacturer, the user or both, depending on location. The assumption should be that both the product centers and laboratories take responsibility for ensuring the regulations are identified and met. However, to ensure that the equipment complies with requirements, any location ordering equipment with locally specific regulatory requirements, these must be specified in the initial FAR. An RFQ or special request pricing quote may be required for purchase of equipment with specific additional regulatory compliance needs.

## 7.2.6 General Wireline Sample Chamber Specifications (Category 0 and 1)

Wireline sample chambers (MDT & RFT) have not been designed to meet a specific standard or code such as those published by the ASME or API for pressure vessels or piping. Large safety factors would require tools to be excessively heavy and long. They are designed using good practice with respect to load bearing surface areas, material cross-sections, radii, and thread engagements. Stresses are calculated using Von Mises criteria for thick walled cylinders. A safety factor of 1.5 to 2.1 at room temperature is included based on the minimum specified yield stress for the material. Chambers are tested to 1000 psi above their rated pressure at the time of manufacture.

The designs of the MDT and RFT chambers have undergone a design review by an independent third party, Det Norse Veritas AS (DNV). As a result, they have issued the following DESIGN VERIFICATION REPORTS (Independent Review Certificates):

- 97-ABD-324 6 Gallon Formation Tester
- 97-ABD-325 RFS-BD 2 ¾ Gallon Sample Unit
- 97-ABD-326 RFS-AF 2 ¾ Gallon Sample Unit
- 97-ABD-327 RFS-BC 2 ¾ Gallon Sample Unit
- 97-ABD-328 RFS-AB 1 Gallon Sample Unit
- 97-ABD-330 RFS-AE 2 ¾ Gallon Sample Unit
- 97-ABD-331 Sample Cylinder - MRTT Sample Modules (MDT 1 & 2 ¾ Gallon Chambers)

The MPSR 450 cc (416 cc with agitator piston) PVT bottle for the MDT Multi-Sample module is exempt from U.S. Code of Federal Regulations, Title 49. These bottles are tested to 1.67 times their rated pressure at the time of manufacture. The DOT calculates the burst pressure as a function of the ultimate strength of the material, not the yield strength. The safety factor as determined by the Von Mises criteria is 1.99. The latest US-DOT (US Department of Transportation) Exemption for the MPSR can be found on InTouch Content ID 3547182.

## 7.2.7 Job Design and Well Integrity

Maintaining the integrity of a well is paramount in delivering a safe, high quality, service to our clients. In addition to following all the measures required to maintain the integrity of individual tools (such as maintenance, certification and traceability of critical parts), at the wellsite the overall Well Barrier Envelope must be established and maintained, and in order to do this all jobs must be designed and planned in accordance with POM section 3.2: Job Design, and Planning Well Barriers.

For RSA operations this applies particularly to the SCAR which is considered to be a Well Barrier Element, but RSA personnel should also be aware of the requirements for Wireline and Slickline or any other system onto which their tools are connected.

The roles and responsibilities of each member of the crew must also be assigned, and this must take into consideration their levels of training and competence.

# 7.3 Reservoir Sampling and Analysis Equipment General Rules

## 7.3.1 Equipment Pressure Rating

All surface sampling and flow control equipment used upstream of, and up to the choke manifold must have a minimum WP rating of 10 000 psi. For sake of standardization, "normal" ratings of new equipment upstream of and up to the choke manifold shall be 10,000, 15,000 or 20,000 psi.

## 7.3.2 Selection of Equipment Working Pressure

1. RSA Sampling Tools

   Downhole sampling tool-charging pressure must not exceed the maximum working pressure of the tool at surface. The increase in temperature downhole will raise the internal pressure of the sampling tool above its working pressure. However, the differential pressure between the tool internal and external well pressure will not exceed the maximum working differential.

2. RSA Surface Sampling Equipment

   A working pressure safety margin of 20 % is mandatory for surface sampling jobs. This means that the equipment **must** be chosen to have a WP rating of 1.2 times the maximum potential wellhead pressure (MPWHP). (The MPWHP can be computed as the maximum undisturbed reservoir pressure less a gas gradient to surface).

   The wellsite pressure rating (or Maximum Allowable Operating Pressure, MAOP) is equal to the value of the wellsite Test Pressure, and cannot exceed the WP rating. Note that this limited margin must be taken into account when designing a surface sampling operation. Any variation must be approved through the exemption process via QUEST. Surface temperature must also be considered, as the MAOP is often dependent on the temperature of the process media.

3. RSA Sample Receptacles

### Conventional Sample Bottle (CSB)

Conventional sample bottles are generally used for collection and transport of pressurized oil samples from a separator or surface manifold. The sample is generally taken at a pressure around 15% of the WP of the receptacle and therefore the safety implications are generally minimal. Once the sample has been taken, it is standard practice to introduce a 10% of sample chamber volume gas cap to allow the sample to expand due to temperature variations and to comply with transportation regulations.

### Single Phase Sample Bottle (SSB)

This type of sample receptacle is used to transport a mono-phase hydrocarbon sample as transferred from a downhole-sampling tool or collected from a wellhead manifold where the fluid will be mono-phase at surface.

The working pressure must not be exceeded during sample transfer or transportation to another location. The SSB is designed to include a nitrogen gas buffer that acts as a pressure accumulator to ensure that the sample is not affected by an expansion or contraction due to temperature variations from the filling ambient temperature.

### Gas Sample Bottles (GSB)

Schlumberger uses a number of manufactured gas sample bottles of Luxfer or Hoke design. Luxfer manufacture sample receptacles from aluminium and the working pressure varies dramatically with the temperature that the cylinder is exposed to. Refer to InTouch Content ID 5023416 for maximum working pressure variation with temperature. If in any doubt, contact InTouchSupport.com for advice.

On no account should mercury come into contact with Luxfer-design cylinders due to the corrosive effect of mercury on aluminium. If any GSB is known or suspected to have been in contact with mercury, it must be removed from service and red tagged immediately. The bottle must then be fully recertified as per major survey requirements as well as having a full body internal inspection with boroscope to check for internal damage and corrosion.

GSBs of aluminium construction (Luxfer type GSB) have an obsolescence age of 10 years from date of manufacture, as per Fluid Sampling & Analysis Field Equipment Guidelines. Refer to InTouch content ID 4935698 for clarification of the use of GSBs > 10 years of age.

Hoke manufacture gas sample bottles from stainless steel and as such are not affected by mercury in the same way as aluminium.

To conform to US and Canadian Transport Regulations, all US-DOT and Transport Canada exempt or approved Gas Sample Bottles must be fitted with a pressure relief device when transporting gas samples. (See InTouch Content ID 3509828 for full details).

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**Note**

When filling any US-DOT Gas Sample Bottles with Hazard Class 2.3 (i.e. samples containing $H_2S$), it is prohibited to fit a pressure relief devise, and forbidden from transporting that particular cylinder by Passenger and Cargo Aircraft. In this case blanking plugs should be fitted in place of the pressure relief devices as standard.

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**4.** MRSS Sample Bottles (MSB)

This is the mono-phase High Pressure/High Temperature sample bottle used in the Wireline Modular Reservoir Single-Phase Sampler (MRSS) and is designed and manufactured by the Oilphase Product Centre in Aberdeen. This bottle is used to capture and transport a mono-phase hydrocarbon sample from downhole to the analyzing laboratory.

The working pressure must not be exceeded during sample transfer or transportation to another location. The MSB is designed to include a nitrogen gas buffer that acts as a pressure accumulator to ensure that the sample is not affected by an expansion or contraction due to temperature variations from the filling ambient temperature.

**5.** RSA PVT Cells

Schlumberger has a variety of Mercury Free PVT cells manufactured by the DBR Technology Center in use throughout its global network of RSA Fluid Analysis Laboratories. Laboratory fluid analysis pressure equipment will generally have a maximum WP of 15 000 psi. For sake of standardization, "normal" ratings of new laboratory equipment shall be 15,000, 20,000, 25,000 or 30,000 psi. Equipment must not be subjected to operating pressures in excess of WP at any time, except during certifying ‘test pressure’ scenarios every five years. When working at pressures close to WP, it is important to set a slightly lower pressure for transfer and other sample tests than the WP. This ensures that the WP is never exceeded during the operation.

**6.** Wireline Sample Chambers

The pressure rating is permanently stamped on the sampling chamber. For Wireline chambers, the rating is located in a machined relief found on either end of the chamber. The MPSR bottles are also engraved with the pressure rating at the end, however, there is not a machined relief. The pressure rating specifies the maximum differential pressure (referenced to the outside (wellbore) of the chamber) to which it can be subjected. High Pressure Sample chambers have a 25 kpsi external pressure (wellbore) rating with a maximum of 20 kpsi differential pressure and are designed for low shock operations only (back of piston open to hydrostatic). The pressure rating shall never be exceeded in any wellbore or wellsite operation.

**7.** Sample Bottles Manufactured in DBR Technology Center

These Sample Bottles exist in a variety of volumes and pressure ratings. They are designed for laboratory use only and are not certified for transportation. As such, they do not appear in the Sample Bottle Shipping Matrix. Under no circumstances must these bottles be shipped containing samples. See InTouch content ID 4895641 and InTouch content ID 5068655 for further information.

## *7.3.3* Pressure Relief Devices

Pressure relief devices provide a safe means of releasing pressure in order to prevent over pressure and ultimately rupture of pressure containing/controlling equipment. A pressure relief device could take the form of a rupture disc, relief valve, back pressure regulator or other device. Rupture discs fitted to lab pycnometers shall be replaced annually as part of the Q-Check (Annual Survey). Rupture discs fitted to GSBs shall be changed at each TRIM redress maintenance event. These measures will ensure that the fitted rupture discs are always in good condition and will prevent premature bursting of the disc. Pressure relief valves on lab analysis equipment shall be tested annually as part of the equipment Q-Check and recorded in RITE. Relief valves in downhole sampling tools shall be set and tested at each redress as per SOPs.

All pressure dispensing vessel assemblies (R2D2) must have a working 163 psi pressure relief valve (Part number 000-3726) fitted and tested prior to each use as part of the MDT-STK TRIM. Replacement relief valves can be ordered via SWPS.

# *7.4* Wireline Sample Chamber General Rules

Wireline Sample Chambers are designed and manufactured by Schlumberger Sugar Land Product Centre (SPC).

Safety factors vary for each of these sampling devices. Safety factors range from 1.56 to 2.1 for Wireline samplers. No sampler should ever have a safety factor less than 1.5. For cylindrical chambers, the burst and collapse pressure are the same. Schlumberger HPS safety factors are based on the minimum yield strength of the material at minimum wall thickness, not on the ultimate tensile strength.

Qualified Schlumberger personnel or Schlumberger approved third party transfer company personnel will operate Wireline Sample Chambers during High Pressure Transfer operations after recovery to the surface.

### Pressure Rating

Wireline Sample Chambers vary considerebly in their volume, pressure rating and safety factor. Table 7-2: Wireline Sample Chamber ratings. N.B. Maximum Temperatures are Downhole NOT Surface Heating Temperatures Wireline Sample Chamber Ratings below details the pressure and temperature ratings at time of publishing.

**Note**
Maximum Temperatures are Downhole NOT Surface Heating Temperature.

**Table 7-2: Wireline Sample Chamber ratings. N.B. Maximum Temperatures are Downhole NOT Surface Heating Temperatures**

| Designation | | | Cylinder | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Code | Part No. | Volume (Gallon) | Pressure (kpsi) | Temp (degF) | $H_2S$ (yes/no) | Material | MinYield Strength (kpsi) | Burst and Collapse Pressure (kpsi) | Safety Factor |
| RFT | | | | | | | | | |
| RFS-AB | H217397 | 1 | 20 | 350 | N | 17-4PH | 150 | 37.08 | 1.9 |
| RFS-AC | H217398 | 1 | 15 | 350 | Y | Ti6Al4V | 120 | 29.67 | 2 |
| | | 1 | 15 | 350 | Y | MonelK500 | 100 | 24.72 | 1.6 |
| RFS-AD | H217395 | 1 | 15 | 350 | Y | Ti6Al4V | 120 | 29.67 | 2 |
| RFS-AE | H223384 | 2.75 | 20 | 350 | N | 17-4PH | 150 | 37.08 | 1.9 |
| | | | 15 | 350 | Y | MonelK500 | 100 | 24.72 | 1.6 |
| RSF-AF | H334514 | 2.75 | 20 | 350 | Y | MP35N | 170 | 42.03 | 2.1 |
| RSF-BB | H217399 | 2.75 | 20 | 350 | N | 17-4PH | 150 | 37.08 | 1.9 |
| RFS-BC | H217400 | 2.75 | 15 | 350 | Y | SSTA286 | 100 | 24.72 | 1.6 |
| | | | 15 | 350 | Y | MonelK500 | 100 | 24.72 | 1.6 |
| RFS-BD | H334518 | 2.75 | 20 | 350 | Y | MP35N | 170 | 42.03 | 2.1 |
| FTS-G | H122950 | 6 | 10 | 350 | N | 17-4PH | 150 | 15.81 | 1.6 |
| FTS-G | H122950 | 6 | 10 | 350 | N | 17-4PH | 150 | 15.81 | 1.6 |
| FLS-A | H124247 | 6 | 10 | 350 | N | 17-4PH | 150 | 15.81 | 1.6 |

| Designation | | | Cylinder | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| RFW-AB | H217396 | 1 | 20 | 350 | N | 17-4PH | 150 | 37.08 | 1.9 |
| RFW-AC | H251394 | 2.75 | 20 | 350 | N | 17-4PH | 150 | 37.08 | 1.9 |
| RFW-AD | H334516 | 2.75 | 20 | 350 | Y | MP35N | 170 | 42.03 | 2.1 |
| RFW-BA | H217265 | 2.75 | 20 | 350 | N | 17-4PH | 150 | 37.08 | 1.9 |
| RFW-BB | H334519 | 2.75 | 20 | 350 | Y | MP35N | 170 | 42.03 | 2.1 |
| **MDT** | | | | | | | | | |
| MRSC-AB | H708820 | 1 | 14 | 400 | N | 17-4PH | 150 | 28.96 | 2.1 |
| MRSC-BB, GA,PA | H708821, H720761, H703660 | 1 | 15 | 400 | Y | TiBeta-C | 165 | 38.04 | 1.9 |
| MRSC-BC, GB,PB | 100060141, 100060144, 100060147 | 1 | 20 | 400 | y | Inconel725 | 130 | 40 | 2 |
| MRSC-CB | H708822 | 2.75 | 14 | 400 | N | 17-4PH | 150 | 28.96 | 2.1 |
| MRSC-DB, JA | H708823, H720763 | 2.75 | 15 | 400 | Y | TiBeta-C | 165 | 38.04 | 1.9 |
| MRSC-DC, JB | 100060142, 100060146 | 2.75 | 20 | 400 | Y | Inconel725 | 130 | 40 | 2 |
| MRSC-EC (FLS-B) | H433598 | 6 | 10 | 350 | N | 17-4PH | 150 | 15.81 | 1.6 |
| MPSR-BA | H433947 | 450cc | 20 | 400 | Y | Inconel718 | 125 | 39.8 | 1.99 |
| **SRFT** | | | | | | | | | |
| SRSC-AA | H434760 | 2.38 | 20 | 350 | Y | MP35N | 160 | 31.21 | 1.56 |
| SRSC-AB | 100039965 | 2.38 | 20 | 350 | Y | Inconel725 | 130 | 40 | 2 |
| SRSC-LA | 100039966 | 2.38 | 15 | 350 | Y | Inconel725 | 130 | 30 | 2 |
| SRSW-AA | H434640 | 2.38 | 20 | 350 | Y | MP35N | 160 | 31.21 | 1.56 |
| SRSW-AB | 100041004 | 2.38 | 20 | 350 | Y | Inconel725 | 130 | 40 | 2 |
| SRSW-LA | 100041005 | 2.38 | 15 | 350 | Y | Inconel725 | 130 | 30 | 2 |
| MDSU | H351043 | 1 | 15 | 400 | Y | TiBeta-C | 165 | 38.04 | 1.9 |

## *7.5* Transportation of Pressurized Reservoir Fluids in Sample Receptacles

Pressurized samples are only to be transported in designated pressure vessels. Under no circumstances should samples be transported from the wellsite in RSA or Wireline downhole sampling tools, unless these have been approved for transportation by the appropriate transportation governing authorities.

The United Nations (UN) Committee of experts produces **Modal Regulations**, which are intended to be applied to all modes of carriage. These Modal Regulations do not themselves have the force of law, but are designed to be used by the relevant transport authorities (IATA, IMO etc.) that add to the basic provisions specific requirements relevant to the mode in question.

Sample cylinders must conform to the requirements of the country or state in which the cylinders are being filled for transport. Heavy fines > $100,000 and /or imprisonment can be imposed on persons not declaring dangerous goods for transportation through incorrect declaration or packaging.

The Testing Services Fluid Sampling and Analysis, Sample Management Standard TS-SQ-S04-FSA (See InTouch Content ID 4214962) and Operating Procedure *OP 241 - Transportation of Dangerous Goods by Air, Sea, Road and Rail* must be adhered to (See InTouch Content ID 3832417) for all shipments of reservoir fluid samples e.g. to and from the wellsite, field locations and fluids analysis laboratories. Only IATA/IMDG trained and certified personnel can ship and declare dangerous goods.

Under no circumstances shall any Reservoir Fluid Sample be exported unless the following criteria have been met and documented on the Reservoir Fluid Sample Shipping Checklist which must be signed off by the Testing Services location Fluid Sampling and Analysis FSM/EIC or Laboratory Manager/Supervisor in order to give the green light for the shipment to authorized and be forwarded to location logistics department for onward transportation.

All cylinders/sample receptacles must be packaged and labeled depending on the substance being shipped and according to the regulations governing the particular mode of transport.

Refer to the RSA Dangerous Goods Guidelines for specific information regarding the labeling and declaration of Reservoir Fluid Samples (See InTouch Content ID 6228198). These guidelines include a Sample Bottle Shipping Matrix, which defines the Transport Authority Compliance, UN Codes and Proper Shipping names pertaining to all sample receptacles supplied by the Oilphase Product Center.

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**Note**

RSA sample bottles and Wireline sample chambers with US-DOT and Transport Canada exemptions or approval must only be used for shipping substances accepted within that approval. For further information consult the written approval/exemption document which should be packaged with the sample receptacles pressure certification within the sample receptacles shipping box.

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## *7.5.1* Air Transport

The International Civil Aviation Organization (ICAO) – Technical Instructions, is a UN agency responsible for regulating the carriage of dangerous goods by air transportation. The International Air Transport Association (IATA) have adopted the ICAO Technical Instructions and the **IATA Dangerous Goods Regulations** are published in order to provide procedures for the shipper and the airline by which substances with hazardous properties can be safely transported by air on all commercial air transport.

The sample receptacle must conform to the relevant packing instructions of the (IATA) Dangerous Goods Regulations, latest edition. This body governs the shipping of the sample receptacle containing dangerous goods.

The shipper must classify the substance being shipped in one of the nine hazard classes and the degree of danger to one of the three packing groups within the class.

## *7.5.2* Sea Transport

The **International Maritime Dangerous Goods (IMDG) Code** is recommended to governments for adoption as the basis for their national regulations on the carriage of dangerous goods by sea. The sample receptacle must conform to the packing requirements of the latest edition of the IMDG code. Sample cylinders must conform to the requirements of the state in which the cylinders are being filled for transport.

The shipper must classify the substance being shipped in one of the nine hazard classes and consider the additional criteria “Marine Pollutant” which may also be applied to the substance.

## *7.5.3* Road and Rail Transport

Unlike the air and sea codes, there is no international consensus on the transportation of dangerous goods by road and rail.

**ADR, the European Agreement Concerning the International Carriage of Dangerous Goods by Road** covers the European area only. There are a number of other contracting states outwith Europe such as the Russian Federation.

**Note**

National, State and Local government agency laws apply in the countries where the sample receptacles are being filled and through which they are transported.

## 7.5.4 US and Canada Transportation Approvals

In the United States of America, the sample receptacles must conform to **US Code of Federal Regulations-US-DOT 49 CFR** fill for export i.e. US-DOT bottles shall be used for transport.

In Canada the sample receptacles must conform to **Cylinders, Spheres and Tubes for the Transportation of Dangerous Goods-CAN/CSA-B339-96**. i.e. TC bottles shall be used for transport.

The Transportation Approvals for all RSA Product Centre designed, manufactured and supplied sample receptacles can be found in the Sample Bottle Shipping Matrix (See InTouch Content ID 3525481).

**Table 7-3: Transport Approvals for Wireline Sample Receptacles**

| Cylinder or Tool | Serial No. Identifier | Transport Approval | Designed |
|---|---|---|---|
| MDT Petroleum Sample Receptacle (MPSR) | MPSR-BA XXXX | US-DOT<br>Transport Canada | Schlumberger SPC |
| 1 Gallon MRSC Sample receptacle | MRSC-XX XXXX | NOT TRANSPORTABLE WHEN FILLED | Schlumberger SPC |
| 2.75 Gallon MRSC Sample receptacle | MRSC-XX XXXX | NOT TRANSPORTABLE WHEN FILLED | Schlumberger SPC |

# 7.6 Sampling Operations and Sample Handling, Heating, Transfer and Bleed Down

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**Note**

The Clarity business system shall be used for tracking and managing all reservoir fluid samples in Testing Services. A Sample Data Sheet detailing all available and applicable reservoir fluid parameters including Pressure, Temperature, $H_2S$ and $CO_2$ shall be created for every sample captured as part of the Clarity sample creation and data entry process. This will facilitate the tracking and management of exposure to each particular reservoir fluid contained within during the sample receptacles lifetime.

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It is essential that the latest controlled Operating Procedures (See InTouchSupport.com) are followed, as the procedures are the correct and safest way to carry out normal sampling, operations and, sample handling, heating, transfer and laboratory operations.

When conducting wellsite operations the appropriated rig/wellsite authorities should be informed and a permit to work issued for the sample heating and pressurized transfer work being undertaken. The locations Permit To Work system should be followed and the issued Permit should reference the applicable Operating Procedure. Work areas should be cordoned off as necessary.

The following is a summary of key pressure safety points that must be adhered to.

## 7.6.1 Connection of Pressure Equipment to Schlumberger Sampling Tools & Receptacles

When Schlumberger personnel contracted by the client are connecting pressure and heating equipment to any Testing Services or Wireline sampling tool or receptacle, the following conditions apply:

- Only Schlumberger designed sample handling, heating and transfer equipment or items that are marked and can be identified as having a pressure rating higher than the expected bottle pressure (formation pressure) may be connected to a Schlumberger sampling tool. e.g. a 20 kpsi WP SSB-VA or 25 kpsi WP SSB-AB must be used when transferring a 19 kpsi sample from an SPMC-20, however it is permitted to a use a 15 kpsi WP SSB-IB to transfer a 10 kpsi sample from an SPMC-20.

- Only equipment which meets Schlumberger minimum standards as per the Testing Services and Wireline POM may be connected to a Schlumberger sampling tool.
- Schlumberger personnel are responsible for making the client aware of these requirements.

A Wellsite Sample Tansfer Operations compliance checklist is available on InTouch Content ID 5384961 and shall be used by Schlumberger personnel to verify POM compliance with respect to any wellsite sample handling, heating, transfer and bleeddown operations involving reservoir fluid samples contained within any Schlumberger, customer or 3rd Party sampling tools, bottles and receptacles.

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**Note**

For Wireline sample drainage from MDT equipment the HARC on InTouchSupport.com 4296720 should be referred to.

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## 7.6.2 Connection of Pressure Equipment to Third Party Sampling Tools & Receptacles

When Schlumberger personnel are contracted by the client to connect pressure equipment to any third party sample chamber the following conditions apply:

- Only Schlumberger designed sample handling, heating and transfer equipment or items that are marked and can be identified as having a pressure rating higher than the expected bottle pressure (formation pressure) may be connected to a third party sampling tool.
- Only equipment which meets Schlumberger minimum pressure operations requirements and standards as per the Testing Services and Wireline POM may be connected to the third party sampling tool.
- Perform HARC prior to handling all third Party Sampling Tools.
- Contact Third Party Company sampling specialist to assist with tool and valve operations as per SOPs.
- Ensure valve and sample chamber configurations are understood and sampling tool drawings are available.
- Ensure heating and pressure limits are understood prior to commencing pressure and heating operations.

A Wellsite Sample Tansfer Operations compliance checklist is available on InTouch Content ID 5384961 and shall be used by Schlumberger personnel to verify POM compliance with respect to any wellsite sample handling, heating, transfer and bleeddown operations involving reservoir fluid samples contained within any Schlumberger, customer or 3rd Party sampling tools, bottles and receptacles.

## 7.6.3 Sampling Tool Charging

Prior to a downhole sampling tool being run in hole, the downhole tool is charged with synthetic oil and oxygen-free nitrogen (OFN) to a pressure relating to the recovery pressure of the tool upon return to well surface. This pressure can be up to but not exceed WP of the tool on surface. The tool should be fully evacuated to a vacuum level of <1 mbar prior to charging with synthetic oil and oxygen-free nitrogen (OFN). The OFN should have a level of oxygen no greater than 0.5 % when used to charge tools. The oxygen level in the Nitrogen cylinder must be checked prior to use.

## 7.6.4 Sampling Tool Rigging-up

Once the tool is fully charged, the rig crew should be made fully aware of the inherent danger associated with equipment under pressure. Equipment being laid out prior to RIH should be cordoned off and the specified rig authority informed. Care should be taken to ensure that pressurized tools are handled correctly. When sampling tools are being made-up it is essential that the connections be tightened at the correct joint using the specified tools.

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**Note**

Pressurized joints shall not be tightened or slackened and Pipe wrenches shall not be used at any time on sampling tools.

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## 7.6.5 Sampling Tool Rigging Down

On return to surface the sampling tool should contain a pressurized hydrocarbon sample in addition to the fluids and nitrogen under pressure used to charge the tool. The handling of the equipment during rig down should be treated in the same way as the rig-up.

Should there be any indication that the tools have not functioned correctly, the situation should then be assessed for pressure hazards. In extreme circumstances, the tool may be partially closed or elastomers may be leaking. In these circumstances it is essential that the rig authorities are involved and a risk assessment carried out to formulate an agreed safe method of handling and de-pressurizing. Controlled Schlumberger Operating Procedures are to be used for handling trapped pressure situations. Design modifications are generally carried out to have potential trapped pressure areas rectified.

## 7.6.6 Sample Transfer and Filling

Only dedicated sample transfer equipment designed for the task should be used. Sample transfers should only be undertaken within the WP of the transfer unit and sample receptacles being used.

All sample bottle certification shall be checked before filling operations to ensure that there is a minimum "safety factor" of 6 months remaining on the valid certificate in order to minimize the risk of certification expiring whilst full during transportation and storage time prior to analysis. Any sample bottles with less than 6 months remaining on the certificate shall be identified for recertification.

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**Caution**

Potential Severity: Light
Potential Loss: Assets
Hazard Category: Pressure

Ensure all applicable pressure and transportation certification expiry is verified e.g. Witnessed Hydrostatic Test to Test Pressure as well as US-DOT and TC certification, as these may of occurred on different dates.

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**Warning**

Potential Severity: Serious
Potential Loss: Assets
Hazard Category: Machinery equipment hand tools

Sample receptacles must never be completely filled with liquid. A gas cap of at least 10% is compulsory for sample transportation to comply with international dangerous good regulations.

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A gas cap of 10% of the bottle sample volume shall be introduced when taking liquid surface samples from a separator, Vx or manifold into a conventional sample bottle (CSB). This is to prevent the liquid sample thermal expansion from reaching the receptacle maximum working pressure during transportation and storage temperature extremes whilst complying to international dangerous goods regulations. In the case of single-phase sample bottles (SSB), a nitrogen buffer is introduced as part of the normal transfer procedure. This is intended to minimise the sample thermal expansion and contraction due to shipping temperature extremes and maintain the sample within the receptacle's WP and above the sample saturation pressure whilst complying to international dangerous goods regulations.

### 7.6.6.1 Transfer and Filling of MPSR Sample Bottles

Schlumberger Wireline sample bottles (MPSR) do not have a facility for a nitrogen buffer gas cap and as such have a number of precautions and guidelines to be followed to ensure the WP of the bottle is not exceeded during transportation. Schlumberger SPC take the position that it is safe to ship an MPSR bottle as long as the following criteria are met:

- NEVER re-pressurize/over-pressure the MPSR bottle after it has come to surface. This requires that when checking the opening pressure by pumping against the piston this pressure must be bled off prior to shutting in the back side of the piston.
- An MPSR bottle is not intended to be used as a transfer receptacle. If a bottle is filled at surface or in a lab then it must have at least 50 cc of ambient pressure air on the backside of the piston to comply with general transportation regulations.
- PVT labs must be informed that if they do a partial analysis of a sample and intend to ship the bottle while under pressure they have to drain all the fluid from the back side of the piston prior to shipping it. This will reduce the pressure back to what it was originally shipped at or lower depending on the volume that was transferred out of the bottle.
- With the low shock technique there is the possibility of over-pressuring the sample above the working pressure of the MPSR bottle downhole. In wells over 20,000 psi over-pressuring the sample is not recommended. The pressure can be bled by opening the exit port prior to closing the MPSR one shot valve. However, even in a reservoir over 16,000 psi the sample can be pressurized to over 20,000 psi. A fluid sample will always cool enough to be below the working pressure of the bottle. However, a pure methane sample may come out of the hole above the working pressure of the bottle.
- In a well that is above 93 degC (200 degF) all samples up to 20,000 psi can be over-pressured (to 24,000 psi).
- In a well that is 79 degC (175 degF) only samples up to 18,500 psi can be over-pressured (to 22,500 psi). In a well that is 66 degC (150 degF) only samples up to 17,000 psi can be over-pressured (to 21,000 psi).
- If very high-pressure wells are being encountered, please contact InTouchSupport.com for a more detailed analysis of what sample pressures can be achieved to remain within the working pressure and shipping regulations.

**Note**

The basic reasoning is that the MPSR bottles are filled with hydrocarbon sample downhole at reservoir temperature; they are then shipped at ambient temperature once at the surface. The fluid at reservoir temperature will shrink as it is returned to surface at a much lower temperature than downhole. The sample will therefore be below WP of the MPSR during shipping providing ambient temperature is never higher than bottomhole sampling temperature.

Keep in mind, that the samples may have been intentionally over pressured downhole before sealing or may contain a gas charge released to the piston after the bottle was filled.

## 7.6.7 Heating of Sampling Equipment and Sample Receptacles (Sample Conditioning)

It is common for reservoir fluid samples to be heated back up to the bottom hole temperature or sampling conditions prior to and during pressurized sample transfer at the wellsite or within a fluids analysis laboratory.

**Always confirm maximum temperature/pressure limits of any sample receptacle/cylinder prior to conditioning any sample**. See InTouch content ID 4056931 for approved heating temperature limits of Testing Services and Wireline sampling tools and transportable sample receptacles. For approved heating temperature limits of DBR non-transportable laboratory sample receptacles, refer to the operating manuals in InTouch content ID 4895641. Please contact InTouchSupport.com if in doubt of the heating limit of any sampling tool or receptacle (including third party sampling tools and receptacles).

**Note**

The use of heat guns in fluid sampling and analysis laboratory and field operations is strictly prohibited.

### 7.6.7.1 Wellsite and Field Location Sample Conditioning

Only heating jackets that have been specifically designed for the purpose of heating sample chambers and sample receptacles may be used for sample conditioning at the wellsite and field location. The pressure build up from the moment heat is applied to the assembly must be monitored and regulated to prevent the over-pressure of the vessel. The pressure and temperature must be regulated to ensure that it is maintained within the specified limits.

**On no account should the heating of the sampling tool or sampling receptacle take place un-manned, i.e. this process must be supervised at all times**.

On completion of the heated transfer the sampling tool should be allowed to return to ambient temperature or less than 15.55556 degC (60 degF) before any further work is undertaken on the sampling tool.

## 7.6.7.2 Fluids Analysis Laboratory Sample Conditioning

It is also necessary for reservoir samples to be heated and pressurized to reservoir conditions prior to and whilst performing PVT related measurements within the Fluids Analysis Laboratory. Only DBR Technology Center designed or/and approved heating jackets and sample conditioning equipment may be used, which has been specified for this purpose.

**The pressure build up from the moment heat is applied to the sample chamber or receptacle assembly must be monitored and regulated under direct supervision to prevent the over-pressure of the vessel at all times.** The pressure and temperature must be regulated to ensure that it is maintained within the specified limits. Direct supervision must be maintained until the pressure has stabilized within the sample chamber or receptacle. Only then may Extended Heating of the Reservoir Fluid Sample be permitted.

DBR Technology Center designed and supplied sample conditioning equipment (including heating jackets and controllers) shall be the preferred technology option, however should any third party supplied equipment be evaluated for use within a fluids analysis laboratory the following conditions shall apply as minimum prior to use:

- All Electrical sample conditioning equipment must satisfy all local government regulatory authority requirements governing electrical and portable appliance manufacture, operation, inspection and test as defined.
- All Electrical sample conditioning equipment and heating jackets must be tagged with a unique ID S/N and tracked in RITE with a schedule of preventative maintenance defined and recorded.
- Dual “J” type thermocouples must be used with all heating jacket and controller systems i.e. there must be redundancy should one thermocouple fail.
- Over-temperature cut out must be incorporated into system to isolate electrical supply to heating jacket if primary circuit fails.
- System pressure must be regulated at all times.

- A HARC is documented and all risk prevention and mitigation measures are implemented prior to use of any third party heating equipment.
- Refer to InTouch Technical Alert Content ID 5025474 for information.

## Extended Heating of Reservoir Fluid Samples

Extended heating of reservoir fluid samples is defined as the heating of a sample bottle or receptacle (e.g. on a restoration bench or in a heating jacket) for a period greater than the time required for the sample pressure and temperature to stablise. This is typically done in a designated fluid analysis laboratory. Samples may need to be restored overnight or over a period of several days i.e. when no laboratory staff are present to supervise the operation. Most samples will be fully restored within 24 hours however, where there is a requirement to continue the heating of a sample with agitation on a sample conditioning system for an extended duration prior to analysis (e.g. for heavy oil samples), the following precautions must be taken as a minimum:

- HARC completed prior to commencing extended heating operation.
- Over-temperature cut out to isolate electrical supply to heating jacket if primary circuit fails.
- Pressure regulated at all times.
- Pressure relief valves set at sample bottle test pressure.
- Appropriate fire appliances and detection equipment.

## Extended Heated Storage in an Oven

Extended Heated Storage is defined as when we disconnect any pressurized sample bottle from the POM compliant sample conditioning equipment and place it in an oven or other heated device in order to keep the sample at elevated temperature pending completion of its analysis. (See InTouch Technical Alert Content ID 4277771). This period of extended heated storage must be kept to a minimum and as low as reasonable practicable and should cease after laboratory analysis project is completed.

When transferring any sample bottles from being heated on sample conditioning equipment into a sample storage oven, pressure control equipment must be connected to the sample bottle in the oven and the pressure monitored until the pressure stabilizes. This is because when samples bottles are placed into the oven, the extremities of the sample bottles, which were covered by the heating jackets on the sample conditioning equipment, will also increase in temperature, therefore increasing the pressure of the reservoir sample inside the sample bottle.

The following conditions apply as a minimum:

- HARC completed prior to commencing extended heating operation in an oven.
- Sample ovens must be intrinsically safe and should have alarms installed to alert of any temperature fluctuations (limit +/- 5 degC).
- All Fluids Analysis Locations shall put in place a sample management procedure and process which covers the management of the extended heated storage of samples and records the in and out movement of samples in the storage ovens within the laboratory.
- All samples entering the oven must have pressure control equipment attached and pressure is monitored and regulated until the pressure has stabilized.
- Only samples on which analysis projects are being conducted shall remain within the sample storage oven.
- Sample bottles may be retained within an oven on extended heated storage for up to a maximum of three months from the day they are conditioned and pressure has stabilized within the oven.
- A routine inspection of the oven must take place at a minimum period of once per month in order to verify sample oven inventory.
- Sample oven temperature and controls must not be changed whilst any samples are in the oven unless pressure control equipment is attached to each sample in order to monitor and regulate the pressure.

See InTouch Content ID 4056931 heating of these sample chambers above these temperatures at stated pressure is forbidden. Heating of these chambers and receptacles is only permitted when using Schlumberger Product Centre designed or approved heating jackets.

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**Warning**

Potential Severity: Serious
Potential Loss: Assets
Hazard Category: Temperature

**Always confirm maximum temperature/pressure limits of any sample receptacle/cylinder prior to conditioning any sample.** See InTouch Content ID 4056931 for approved heating temperature limits of Testing Services and Wireline sampling tools and transportable sample receptacles.
For approved heating temperature limits of DBR non-transportable laboratory sample receptacles, refer to the operating manuals in InTouch Content ID 4895641. Please contact InTouchSupport.com if in doubt of the heating limit of any sampling tool or receptacle (including third party sampling tools and receptacles).

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**Note**

The use of heat guns in fluid sampling and analysis laboratory and field operations is strictly prohibited.

**Note**

For heating temperature and WP limits of 20 Litre Luxfer Gas Sample Bottles (GSB-L20, GSB-LD20, GSB-LP20) refer to InTouch Content ID 5023416.

## 7.6.7.3 Periodic Maintenance and Testing of Sample Conditioning Equipment

All Sample Conditioning Equipment (including all heating jackets and controllers) shall be subject to a periodic schedule of preventative Maintenance and Testing. All locations must follow Schlumberger standards as well as local government regulations, or client standards as applicable.

In the case of conflict, the stricter requirements shall apply:

- Records of all inspection and tests shall be maintained by the location.
- Equipment passed as safe shall be tagged (Green RITE Label) with a date for next inspection.
- Immediately remove from service and red tag any equipment that has damaged plugs, cables, leads, connections or is found to be inoperable.

The following inspection and test requirements and schedule shall be regarded as a minimum (as specified in RITE File Code Catalogue):

Visual Check by the user:

- Check for visual evidence of damage to leads, connectors, thermocouples, jacket material, insulation etc.

  This shall be done before first use, after repair and prior to each use.
- Inspection and Testing by a Third Party.
- Periodic visual inspection and test by a third party and use of Portable Appliance Tester (PAT) equipment or equivalent.
- Equipment shall be checked for insulation damage/earth leakage. This shall be done every 12 months as a minimum and after repair.

## 7.6.8 Transfer into and from PVT Cells (including samples at pressures > 15 kpsi)

For Operating Procedures for the transfer into and from PVT cells with reservoir fluid samples refer to the PVT Analysis Reference page on InTouchSupport.com.

For all fluids analysis studies involving samples >15 kpsi contact InTouchSupport.com. For a full technical review as per Section 7.9.3: HP/HT Operations and Section 7.9.4: Ultra-HPHT Operations.

## 7.6.9 Use of Pycnometers

Pycnometers are pressure rated assemblies employed to gravimetrically determine the density of a pressurized fluid or gas. Pycnometers can also be used in conjunction with laboratory fluids analysis equipment to determine the gas oil ratio (GOR) of a live fluid. These measurements all involve filling the pycnometer with a reservoir fluid or gas from a PVT Cell or sample receptacle.

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**Warning**

Potential Severity: Serious
Potential Loss: Assets
Hazard Category: Pressure

The pressure of the sample in the PVT cell or sample receptacle may far exceed the WP of the pycnometer.A calculation must be performed to determine the maximum volume of sample that can be safely bled into the pycnometer. See InTouch content ID 5009451 for information regarding the use of pycnometers and sample volume calculations.

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The following conditions apply to the use of pycnometers in reservoir sampling and analysis operations:

- Pycnometers are only to be used by personnel trained in the operation of high-pressure laboratory equipment and with POM Level 3 (SAM-L3) pressure certification.
- InTouch SOPs must be adhered to at all times when operating any pycnometer.
- All pycnometers used in fluid analysis operations must have a unique serial number and working pressure marking and must be tracked in RITE.
- A valid quality file is to be maintained whilst they are in service.

- Maintenance events shall be performed as per requirements stated in RITE FCC.
- All pycnometers supplied by DBR Technology Center shall be fully POM compliant.
- Pycnometers shall be junked after 5 years of service therefore major recertifications are not required.
- All pycnometers shall have a pressure relief device (rupture disc) fitted at all times to prevent overpressure as per InTouch SOPs.

Care must also be exercised when flashing from a pressurised vessel into a gasometer. See InTouchSupport.com for validated SOPs.

## 7.6.10 Pressure Bleed Down from Sampling Tools and Sample Receptacles

High pressure gases and fluids are required to be bled down from sampling tools and sample receptacles during the course of normal fluid sampling and analysis operations.

These pressurized gases and fluids may consist of compressed gas (such as nitrogen), water/glycol, synthetic oil (Mobil 1) or reservoir fluids (oil, gas, condensate, water).

Engineering controls shall be in place to eliminate the production of pressurized jets of gases and fluids where practicable and in order to facilitate the safe and controlled bleeddown of pressurized gases and fluids to atmosphere where necessary. Correct body positioning and hand placement is essential at all times during any bleeddown operations.

Bleed down operations may only be conducted when an InTouch validated SOP or Best Practice exists for performing a specific bleed down operation.

The InTouch SOP or Best Practice must be strictly adhered to at all times.

For the specific case of high pressure gas/gas condensate blow downs, refer to InTouch Best Practice 6211844 which details extra specific instructions for the safe blow down of these samples.

**Danger**
Potential Severity: Major
Potential Loss: Assets
Hazard Category: Human

Pressurized jets from fluid sampling and analysis bleeddown operations have the potential to inject gases fluid through the skin and into the soft tissues of the body. Entry point wounds may look insignificant however internal dispersal of fluids may be widespread through the body tissues.
**IMMEDIATE SPECIALIST MEDICAL ATTENTION MUST BE SOUGHT IN ALL CASES** for specialized treatment to ensure all wounds are thoroughly treated and cleaned. If left untreated, these injuries can develop very serious medical complications.

When performing any pressurized gas and fluid bleed down operations, the following shall be adhered to at all times:

- A job specific risk assessment (HARC) shall be completed and all necessary risk prevention and mitigation measures shall be in place prior to commencing bleeddown operations of pressurized gases and fluids.
- Where $H_2S$ is suspected refer to SLB-QHSE-S015 $H_2S$ (Hydrogen Sulphide) Standard and Appendix E of this manual.
- Where a reservoir fluid sample is to be conditioned before bleed down, additional hazards (for example electrical, high temperature fluids) shall be identified and sufficient control measures put in place.
- All potential sites of gas and fluid release and equipment bleedholes shall be identified and known by the operator prior to commencing any bleeddown operations.
- Body shall be kept out of the "line of fire" of all potential sites of gas and fluids releases at all times and hands and fingers shall always be kept well away from bleedholes to avoid potential injury.
- Dedicated bleed down valves/manifolds/fittings as defined in InTouch SOP and Best Practices shall be used at all times (e.g dedicated SRS/SLS bleed down manifold).
- A dedicated needle valve shall always be used to control flow. Never control pressurized gas and fluids flow by only using the integral valves on a sampling tool or sample bottle.

# 7.7 Sampling and Analysis Manifolds, Hoses, Liners, Fittings and Connectors

Manifolds, hoses, liners, pressure fittings and connectors for sampling and analysis equipment and kits should only be purchased from a Schlumberger Product Centre via OneCat catalog or SWPS. This equipment may also be procured through a Schlumberger approved vendor provided they conform to the Testing Services POM. See section 7.11.1: Purchase of New Equipment.

Manifolds, hoses, liners, fittings and connectors' pressure ratings vary considerably with temperature. Manufacturers' specifications should be consulted to ascertain the correct working pressure/temperature for a manifold assembly of varying components. For specifications on the application and use of Line Pipe (NPT) and Fittings, refer to 4: Surface Equipment of the POM.

Proprietary connection types such as Swagelok, A-lok pipe compression fittings should not be mixed even though some manufacturers claim interchangeability.

Swagelok fittings come in a large variety and should be chosen carefully. When selecting a product, the total system design must be considered to ensure safe, trouble free performance. Function, material compatibility, adequate ratings, proper installation, flow rate, operation, and maintenance must be taken into consideration and applied correctly. Only appropriately trained personnel should make-up compression fittings (e.g. Swagelok training).

Teflon tape or thread sealant is used only on NPT connections. In rare cases it may be forbidden by the product operating or maintenance manual.

Only forged stainless steel or better (e.g. Inconel) fittings shall be used. Cast iron and braised steel fittings are forbidden. Line pipe (NPT) threaded fittings up to 1/2 in. nominal diameter may be used up to a maximum of 10,000 psi WP provided the manufacturer working pressure rating is not exceeded.

Pressure gauges should always be “safety pattern” which entails that the case will contain a rupture from a burst bourdon tube and will not fragment the gauge glass. Wetted parts should be suitable for the well fluid being sampled i.e. K500 Monel components for $H_2S$ service.

For the available Wireline MDT Sampling Drainage Equipment (High Pressure and Low Pressure) refer to InTouch Content ID 3442037.

## 7.7.1 General Safety Rules

- Never bleed system pressure by slackening fittings or connections. Use the bleed valve in the system.
- Ensure correct body position for task, i.e. body out of the line of fire, fingers away from bleedholes.
- Never tighten/slacken fittings when a system is pressurised.
- Always use proper thread lubricants and sealant on tapered pipe threads.
- Avoid combining or mixing materials or fitting components from various manufacturers e.g. tubing, ferrules, nuts and fittings bodies.
- It is important that designers and users consider hose and hose assemblies as having a finite life, therefore maintenance and replacement is usually necessary at specific intervals.
- Always use traceable components in pressure assemblies. Pressure fittings should be marked with traceability information such as:
  - Manufacturer logo or identification
  - Part number
  - Heat number
  - Maximum working pressure
- Never use components with no markings or traceability.
- Only appropriately trained personnel should make-up compression fittings (e.g. Swagelok training).
- Gas regulators (for example those used on nitrogen, helium, argon, air cylinders) must be visually inspected before each use. Damaged/faulty regulators must be removed from service immediately and junked. Attempts should not be made to repair damaged/faulty regulators - a replacement must be obtained.
- Before each use, gas regulators must be checked to see that they are compatible with the gas cylinder/type to be used. Regulators vary widely (thread type, pressure rating/output, material) so the correct one must be selected for the task being performed. High potential HSE incidents have occurred where gas cylinders have been used with inappropriate regulators.
- Air blow guns must be of the safety type i.e. with bleed holes on the side of the nozzle. This will prevent high pressure air from being blown through the skin.

## 7.7.2 Connection of Wellsite Analysis Equipment to Pressurized Systems

Wellsite chemistry equipment (e.g. for Mercury, Radon, $H_2S$ analysis) may only be connected to pressurized systems if the following controls are in place:

- All testing services locations performing wellsite analysis operations must adhere to the **Fluid Sampling and Analysis Field Operations Service Delivery Procedure (SDP)**.
- A job specific risk assessment (HARC) must be defined and all identified risk prevention and mitigation measures are to be in place prior to starting any wellsite analysis operations.
- All locations are to ensure that either a Standard Operating Procedure (SOP) or InTouch validated Local Best Practice is in place before conducting any wellsite analysis operations.
- Whilst sampling gas into any non-pressure rated wellsite analysis equipment/vessels (such as dreschells, gold sand traps etc.) the line pressure must be regulated using a micro-metering valve (SLB Part Number 000-2666).
- Plastic tubing and connectors must be placed immediately downstream of the micro-metering valve to act as the weak point in the system. These will simply pop apart in the event of any over-pressurization of the equipment and avoid over pressurization of any system.
- All locations are forbidden to use any glass $H_2S$ gas scrubber vessels unless methodology, rig-up and procedure is validated by InTouch.
- Failure to comply with these requirements could result in serious injury to personnel and damage to equipment.

## 7.7.3 Metal Liners/Piping/Tubing Rules

The following rules shall apply to metal liners and metal piping and tubing as used in Fluid Sampling and Analysis operations, sampling kits and equipment assemblies only.

- Metal tubing material should always be softer than fittings material.
- When tubing and fittings are made from the same material, tubing must be fully annealed.

- Surface finish is very important to ensure proper sealing. Tubing with any kind of depression, scratch or other surface defect may not seal, particularly with gas service.
- Liners/Piping/Tubing which is misshapen and will not easily fit through fitting nuts, ferrules and bodies should never be forced and should be replaced.
- Metal liners (for example those used in fluid analysis laboratories, sample transfer kits, PVT-XP kits etc.) shall have a finite life. Metal liners shall be used for a maximum of 1 year service and then junked.
- Metal liners/piping/tubing shall be as short as reasonably practicable and be routed and secured as appropriate for the task being performed. Liner inventories in fluids analysis laboratories and workshops shall be kept to a minimum.
- See InTouch content ID 5162804 for information on metal tube bending including minimum bend radii. Only trained personnel using specialized pipe bending equipment shall conduct tube bending operations.
- All metal tag, stamped with the maximum working pressure, material of manufacture and date it was made up shall be attached to all metal liners and transfer lines. Information on tagging metal liners (including part numbers) can be found in InTouch content ID 5162807.
- Metal liners must be visually inspected before each use. Damaged/faulty liners must be removed from service immediately and junked.

  Liners which are part of the fixed plumbing of a system e.g. those which are part of the DBR PVT cell, shall be replaced every 5 years as part of the major survey.

## 7.7.4 Hose Rules

This sub-section refers to the use of flexible, pressure rated hoses such as rubber hoses used for compressed air, synflex hoses used for nitrogen, parker hoses on FTU pumps, braided metal hoses in surface sampling kits etc.

The following rules apply to these hoses:

- All hose components to be inspected prior to installation, inspect hose for I.D. obstruction or damage such as blisters, looseness or cracks in the hose cover and evidence of it having been kinked. All damaged components shall be removed from service and junked immediately.
- End connections shall be machined in a single piece or assembled with threads. No brazed connections are permitted.
- Check couplings for thread damage or bent coupling components.

- Hoses shall be carefully routed and secured where possible. Many problems can be avoided by installing hose and hose assemblies away from hot equipment such as exhaust manifolds. Insulating heat shields may be necessary in some cases.
- Minimum Bend Radius: Tight bends that exceed the hose recommended minimum bend radius should be avoided. Spring guards or stress relief sleeves may be required to protect against exceeding prescribed minimum bend radii.
- Torsional Flexing: Where equipment parts exhibit relative motion, hose connections should be located so hoses bend instead of twist.
- Pressurized hoses with crowfoot connections fitted shall be secured with whipchecks and R-clips at every connection.
- Hose material must be according to SAE codes for the appropriate fluid, mineral oils, water, etc.
- Each individual hose section must carry stainless steel (rust free) or thermo retractable identification rings showing at a minimum the manufacturers part number, manufacture date and maximum working pressure.
- Hoses must be pressure tested to maximum working pressure annually QC and 5 yearly CE in test bay. Note SSK WP = 1500 psi, WSK WP = 10,000 psi.
- Surface sampling hoses shall be secured with whipchecks at both the sample point and sample bottle ends.

## 7.7.5 Connection Rules

Follow the manufacturers' coupling installation instructions, attach only the couplings specified for each hose design and do not mix components that are produced by different manufacturers.

- Proper coupling end selection is very important to eliminate twists and kinks in installed assemblies when connecting couplings to port connections. Swivel couplings are designed to allow for the hex rotation during tightening, and bent tube or elbow couplings can eliminate kinks.
- Torque Wrench Application: Use torque values where specified when tightening coupling connections to prevent leakage and damage.
- Final Check Out: After components are assembled, purge entrapped air and pressurize system to maximum operating pressure. Inspect for leaks and proper function prior to every job.

### 7.7.6 Earthing Rules

- When taking atmospheric (dead) oil samples earthing cables with clips MUST be fitted between the sampling hose end outlet and the sample can and also from the sampling can to the separator earth point. These earthing cables MUST be fitted prior to and during sampling.
- Perform regular electrical conductivity tests on all designs serving as static electricity discharge paths.
- Sample heating equipment must be suitably earthed during use at all times.
- PhaseSampler heating equipment must be earthed using the dedicated clips/straps.

### 7.7.7 Pressure Test Manifolds

Refer to section 4.4.12.3: Manifolds made from Fittings.

## 7.8 Sampling and Analysis Equipment Pressure Testing

Whenever sampling equipment is used at the wellsite for a sample transfer or prior to a sampling operation, it must be pressure tested after it has been completely set up, before opening communication to the well fluids or running in the hole. In normal conditions, routing well flow through any section of sampling equipment not pressure tested at the wellsite should be avoided.

Laboratory Analysis Equipment must be pressure tested after being re-assembled and prior to use or charging samples into the vessel.

### 7.8.1 Testing Services Basic Wellsite and Laboratory Pressure Test Policy

1. All components used shall have a valid Annual Survey including a hydrostatic test to Working Pressure, WP. Equipment lacking a current test record shall not be used. Enough calibrated gauges shall be mounted on the equipment, to be able to monitor pressure in each segment at all times.
2. The Maximum Allowable Operating Pressure (MAOP) shall be equal to the wellsite Test Pressure.

The wellsite Test Pressure shall never exceed the Schlumberger equipment WP rating, or the client Well head working pressure rating, whichever is lower.

3. **Wellsite Test Pressure shall be 1.2 times the Maximum Potential Wellhead Pressure (MPWHP)**. If the client does not want the wellhead to be subjected to this pressure, the Test Pressure shall be equal to the MPWHP or to the maximum pressure specified by the client, whichever is greater.

   The following comparative values of pressures are to be respected:

   Wellsite Test Pressure = MAOP = 1.2 MPWHP < WP.

   If no wellhead pressure is expected the equipment shall be tested at 25% of its WP.

4. When wellsite pressure testing, low-pressure lines shall be kept open ended to prevent over pressuring in case of a leak. For elements protected by a pressure-relieving device or a pilot, the Test Pressure shall be limited to 90 % of the PSV or HI-pilot setting, or the pressure-relieving device shall be isolated or removed.

5. Pressure testing of sampling equipment shall be carried out with a nonvolatile, non-compressible liquid such as ethylene glycol water based fluid.

   Use of flammable liquids or well fluid is strictly forbidden. This includes diesel.

   Testing with flammable gas is forbidden.

   **Testing sampling equipment with nitrogen is strongly discouraged**. It has been proven that the benefits from a gas pressure test do not measure up to the potential danger associated with the compressed gas. If client insists in testing with nitrogen, the equipment must be tested first with liquid. The maximum nitrogen test pressure cannot exceed the working pressure of the vessel.

   Additional safety measures such as securing all hose sections firmly with chains or wire rope must be implemented if testing with nitrogen.

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**Note**

Some sampling and analysis equipment (for example PVT cells) must be tested with nitrogen due to contamination issues associated with using other fluids. Extreme caution must be exercised as compressed gases store far more energy than incompressible fluids, such as water. Test pressure must not exceed the maximum working pressure of the equipment. Chambers should be fully evacuated to < 1 mbar and oxygen-free nitrogen used (maximum 0.5% $O_2$). Pressure testing with nitrogen shall only be performed where a standard operating procedure exists, either in an equipment operations/maintenance manual or InTouch validated best practice. The volume capacity to be tested shall be kept as low as reasonably practicable.

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6. The occurrence of a wellsite or laboratory pressure test, and the wellsite or laboratory pressure test value shall be recorded.
7. Adequate warning signs should be displayed, and all unnecessary personnel cleared from the vicinity of the equipment under test, while pressure testing is in progress.
8. To carry out the body pressure test, fill the assembled equipment with the appropriate test liquid; making sure all air is bled from the system. Apply Test Pressure slowly. Hold Test Pressure for at **least three minutes** (or the whole time needed to verify that there are no leaks) after pressure has stabilized at the chosen test value. Observe for leaks or pressure drops. Bleed pressure to zero. Apply Test Pressure again for a minimum of **three minutes**. Bleed Test Pressure to zero.
9. If a leak is found, or an unexplained pressure build-up or pressure drop is experienced during the test, the test should be stopped, pressure vented, all lines inspected, and the defective assembly repaired or replaced. The complete pressure test procedure should be repeated after repairs.

   Never attempt to closely inspect or repair the leak while equipment is under pressure.
10. In addition to the body test, valves should be operationally tested.
11. Detailed procedures for wellsite pressure testing of sampling and analysis equipment are to be found in RSA Operating Procedures on InTouchSupport.com.

### 7.8.2 Wireline Basic Wellsite Pressure Test Policy

1. Wireline Sample Chambers are not required to have a wellsite pressure test. The chambers must have a low-pressure test, 100 psi minimum, to test the integrity of seals following any chamber service.
2. Wireline Drainage Equipment (Christmas Trees) are not required to have a wellsite pressure test. The equipment should have a low pressure test, 100 psi minimum, to test the integrity of the seals following Christmas Tree services.

## 7.9 Special Operations and Environmental Limits

It is critical that the integrity of all pressure equipment is maintained during all Reservoir Sampling and Analysis (RSA) operations and throughout the lifetime of the equipment.

**Warning**
Potential Severity: Serious
Potential Loss: Assets
Hazard Category: Machinery equipment hand tools

Exposure to environmental conditions outwith the equipment operating envelope may result in catastrophic failure of the pressure equipment integrity and subsequent release of its contents including flammable hydrocarbons and $H_2S$. See InTouch Content ID 4829184 for an example of the consequences of using fluid sampling and analysis equipment out with its operating limits.

Should any fluids sampling and analysis equipment be exposed to any conditions out with its pressure, temperature or metallurgical operating limits, the equipment must be immediately taken out of service and a full integrity check shall be performed, as per Major Survey requirements defined in the equipment Operations and Maintenance Manuals and RITE Field Codes, independent of its current certification status. Contact InTouchSupport.com should any filled sample bottles be found to contain reservoir fluids and gases that fall out with the particular bottle operating envelope. If in any doubt of equipment operating envelopes contact InTouchSupport.com.

A thorough technical evaluation and review is therefore necessary when planning any reservoir sampling and analysis special operations such as those in $H_2S$ (Severe Service), HP/HT, Ultra HP/HT, aggressive fluids, harsh conditions and Cold Weather/Arctic environments. In addition the time any pressure equipment spends downhole e.g. during drill stem testing or is likely to be exposed or in contact with reservoir fluids e.g. during sample storage, must be taken into consideration.

This technical evaluation and review is required to ensure correct seal and pressure equipment materials are selected for the expected environment and to ensure the correct sampling tool priming and power fluid pressures are selected in order to prevent over pressurizing of the tools downhole and compromise the integrity of the tools.

Tool power fluid pressures must be set as low as reasonably practicable to achieve the sample recovery pressures required whilst remaining within the equipment operating limits.

## 7.9.1 Service Delivery Procedure (SDP)

To facilitate the technical evaluation during the job design and planning phase of all Reservoir Sampling and Analysis special operations InTouchSupport.com, must be contacted as part of the Field and Laboratory operations Service Delivery Procedure (SDP) technical review requirements.

See InTouch Content ID 4387350 for Fluid Sampling and Analysis Field Operations - Service Delivery Procedure (SDP).

See InTouch Content ID 5084876 for Laboratory Fluids Analysis Operations – Service Delivery Procedure (SDP).

Service Delivery Procedure (SDP) for Laboratory Rock Analysis Operations is being worked on at the time of release of this document, but will be published on InTouch during early 2014.

All job design and planning related tickets submitted to InTouchSupport.com to support SDP Technical Reviews for Field and Laboratory operations should meet the requirements of the following InTouch Contents in order that the technical experts can fully evaluate the planned operation.

See InTouch Content ID 4250336 for RSA Field Sampling & Analysis Operations - Job Design and Planning Requirements for HP/HT and severe service operations.

See InTouch Content ID 4999072 for RSA Laboratory Analysis Operations - Job Design and Planning Requirements for HP/HT and severe service operations.

### 7.9.1.1 Product Metallurgy Limitations

Product metallurgy limitations for Testing Services and DBR-TC Fluids Sampling and Analysis equipment have been defined.

Testing Services Field Sampling and Analysis equipment must be operated within the limits specified in InTouch Content ID 4945787 Oilphase Product Limitations in Sour Environments.

DBR-TC Laboratory Fluids Analysis equipment must be operated within the limits specified in InTouch Content ID 4993534 DBR Product Limitations in Sour Environments.

All third party and client supplied equipment metallurgy must be evaluated as part of job design and planning phase with respect to (NACE MR-0175 latest revision).

This includes all third party fluid sample receptacles and core holders which may be used to contain samples with $H_2S$ or other potentially corrosive fluids or fluid mixtures.

### 7.9.1.2 Elastomer Selection Guidelines

Elastomer and O-ring selection guidelines have been defined for Fluids Sampling and Analysis equipment.

See InTouch Content ID 4300827 for Fluid Sampling and Analysis Equipment - Seal Selection Recommendations Chart and Information.

See InTouch Content ID 4571226 for O-ring chemical compatibility & Seal chart for DBR PVT cell.

See section 2.5.7 for the storage of O-Rings.

## 7.9.2 $H_2S$ operations

1. Refer to Testing Services POM Appendix D, NACE MR-0175/ISO 15156 for details on sour environments determination and metallic material requirements for use in environments containing $H_2S$ in oil and gas production.

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**Note**

$H_2S$ Partial Pressure (PP) = Total Pressure (**) (psia) x $H_2S$ concentration (ppm) x $10^{-6}$.

(**) Total Pressure is the maximum pressure the equipment will be subject to, it will be WHP for surface equipment or maximum anticipated internal pressure at the tool level for downhole sampling, DST or Subsea equipment.

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2. Refer to **$H_2S$ Standard SLB-QHSE-S015** for all safety operating rules that must be followed on any wellsite, field or laboratory fluid sampling and analysis operation where the presence of $H_2S$ is suspected or known.
3. All $H_2S$-rated fluid sampling and analysis equipment metallurgy must conform to NACE Standard MR-0175/ISO 15156 (latest edition).
4. $H_2S$-rated elastomers shall be installed where necessary.
5. Any piece of equipment, which cannot be positively identified as $H_2S$-rated shall be considered not suitable for $H_2S$ Service.

6. Repairs and modifications to $H_2S$-rated equipment can only be carried out in qualified shops, approved by a Schlumberger Technology Center. Welding must conform to NACE Standard MR-0175/ISO 15156 rules.
7. Operating limits of Wireline Sample Chambers in $H_2S$ Environments can be found on InTouch Content ID 4195304 and InTouch Content ID 4223717.
8. Prior to the venting or bleeding down of any sample(s) from any sample receptacle, the $H_2S$ content of the sample must be determined from the sample datasheet, welltest report or fluids analysis report etc. Should $H_2S$ be expected, the appropriate risk prevention and mitigation measures shall be taken prior to venting the sample as per $H_2S$ Standard SLB-QHSE-S015.
9. Laboratory experiments on samples containing $H_2S$ shall be performed in a designated and isolated $H_2S$ area.
10. Locations shall have in place an Emergency Response Plan to manage any accidental $H_2S$ releases.
11. **Hazard Analysis and Risk Control Standard SLB-QHSE-S020** shall be complied to with regards to all operations at the wellsite, field, or laboratory involving the potential production of $H_2S$.

## 7.9.3 HP/HT Operations

HP/HT wells are those that begin at 150 degC (302 degF) and 10000 psi (68.95 Mpa) as defined in Testing Services High Profile Job Definitions.

HP/HT Reservoir Sampling and Analysis operations may encompass reservoir fluid open hole and cased hole downhole sampling, wellhead sampling, wellsite analysis, laboratory and sample storage operations.

All HP/HT operations shall be subject to a full technical review as per the appropriate SDP requirements as per Section 7.9.1: Service Delivery Procedure (SDP).

## 7.9.4 Ultra-HPHT Operations

Ultra HP/HT wells are those that begin at 205 degC (401 degF) and 20000 psi (137.90 Mpa) as defined in Testing Services High Profile Job Definitions.

For all Reservoir Sampling and Analysis operations planned within this range contact InTouchSupport.com to assist in a full technical evaluation of equipment metallurgy and elastomers as per the appropriate SDP requirements defined in Section 7.9.1: Service Delivery Procedure (SDP).

## 7.9.5 Aggressive and Harsh Environments (Sand Production, Frac Jobs)

For all Reservoir Sampling and Analysis operations involving aggressive fluids (e.g. acid, high C02 and injected chemicals) and harsh environments (e.g. sand production, propant injection and frac jobs) contact InTouchSupport.com to assist in a full technical evaluation of equipment and elastomers as per the appropriate SDP requirements defined in Section 7.9: Special Operations and Environmental Limits.

Metallurgy must be evaluated with respect to the environment to be encountered.

Elastomers compatible with the environment must be installed where necessary.

## 7.9.6 Cold Weather Arctic Operations

1. Arctic operations are carried out usually down to -40 degC (-40 degF) ambient temperature, and sometimes as low as -57 degC (- 70.6 degF).
2. Operations in sub-freezing weather -57 degC (-70.6 degF) require special precautions with respect to equipment, procedures, and personnel safety. There is no officially accepted definition of cold weather/arctic environment, but a widely used one is when temperature goes below – 29 degC (-20.2 degF). Detailed Arctic operations guidelines are outside the scope of this document.

*Main areas to watch are:*

1. Materials performance in extreme cold.

   Metallic materials of pressure-containing envelopes and lifting frames become brittle in extreme cold. The minimum Design Temperature of Pressure containing parts of Standard Surface Testing equipment are rated to 0 degC (32 degF) according to North Sea requirements or -29 degC (-20.2 degF) according to API, ASME, and ANSI construction codes. (Note that some clients and some regulatory authorities, e.g., NPD in Norway, have requirements in excess of what stated in the reference construction codes.)

   Special equipment, and materials specially treated and qualified (Charpy toughness tests), as specified by appropriate API, ASME or ANSI construction code, shall be used below -29 degC (-20 degF).

For cold weather operations the equipment specification and the local certification requirements shall be carefully analyzed to verify whether the specifications are adapted to the environment and comply with local regulations.

Standard elastomers become hard and brittle. Arctic specification O-rings that can energize down to -57 degC (-70.6 degF) and arctic specification hoses for sampling are available for Arctic environment.

2. Problems with hydrates or icing, at low temperatures

   The very low ambient temperatures increase the probability of plugging through icing or hydrates formation. Even in low GOR wells, gas can segregate during shut-in periods, and produce plugging hydrates when coming in contact with untreated water. Any water used for pressure testing or otherwise pumped into the test string, must be mixed with ethylene glycol or other antifreeze compound in suitable proportions for the minimum temperature expected. Common antifreeze compounds are methanol and ethylene glycol. Methanol is more efficient in eliminating already formed.

   Ice/hydrate plugs, but it is toxic and attacks elastomers seals. It must be used sparingly.

   Every effort must be made to maintain the effluent at a temperature above freezing or hydrate formation points using hazardous area heating tapes where possible.

   Whenever possible, the sampling equipment should be located indoors. (Ventilation and safety system must be designed accordingly). If the equipment is located outdoors, thermal insulation, heat tracing of pipes with steam or electric tapes, must be planned.

3. **Hydraulic oils must be chosen so that their viscosity remains in a workable range at low temperatures.**

4. **Elastomer specification should be utilized such that they are suitable for the applicable range of temperatures.**

## 7.9.7 Working with Pressurized Mercury

Mercury has several potential routes of entry in to the body. It can be absorbed through skin, dermal contact, eye contact, inhalation (vapors) or ingestion. Mercury is very hazardous in case of skin contact (irritant), ingestion or inhalation. It is also Hazardous in case of skin contact (corrosive, permeator). High pressure mercury jets in to the flesh could prove to be fatal.

For this reason extreme caution must be used and strict HSE requirements must be put in place, in all Schlumberger Reservoir Laboratories Rock Analysis facilities, where mercury; especially pressurized mercury; is being used onsite.

The following is a list of requirements for working with pressurized mercury within a Rock Analysis Facility:

1. Detailed equipment operating and maintenance procedures (SOP/manual) and a detailed mercury-specific Hazard Analysis (HARC) must be in place.
2. All defined Mercury Equipment maintenance (with the exception of the basic maintenance functions, which are outlined in the Mercury Porosimeter Maintenance Plan) must be performed by the equipment supplier (Micromeritics), and a full maintenance schedule needs to be in place for all pressurized mercury equipment.
3. All aforementioned POM requirements must be strictly applied to the use of any analysis equipment that uses pressurized Mercury. Under no circumstances should any fittings be cracked or loosened while under pressure. Bleed valves must be used in the pressure system where trapped pressure is possible, and to allow the safe relief of pressure prior to disconnecting any fittings that are mercury-wet. Any automated pressure relief valves (ie : solenoid valves, etc) must not be disabled under any circumstances.
4. When performing maintenance on a pressurized mercury system, all pressure must be bled from the entire system, and extreme caution shall be employed. A specific focus should be made on hand positioning in relation to potential areas from which there is any risk of release of trapped pressure, causing high pressure jets (ie : weep holes on autoclave valve blocks, fitting connections, etc).
5. All fittings, valves and piping are to be rated only for high pressure (> 10,000 psi), and only metal-to-metal seals shall be used on all mercury-wet pressure holding connections. Fittings using elastomers should not be used for mercury-wet pressure holding connections.
6. All pressurized mercury-wet liners, connections and valves must be rated for working pressures at least 1.5 x equipment maximum operating pressure, and liners which are not part of the permanent fixed piping must be replaced annually (i.e.: liners that connect to sample bottles and are constantly connected and disconnected during each equipment operation cycle).
7. Shielding must be present to provide a physical barrier between the person operating the equipment and the pressure holding parts (i.e.: absence of exposed pressure parts, where possible, projectile resistant protective screens should be used to close off the front of the fume hood, etc).
8. All Mercury porosimetry equipment is automated and this functionality should not ever be turned off. During pressurization of the system the operator should never be present inside the fume hood area. A physical barrier should always be between the operator and the equipment when mercury pressure is being ramped up.

**9.** Valves, fittings and weep holes must be fully contained within the protective casing on all mercury porosimetry analysis equipment. Protective casing should never be removed from, or modified on any equipment which uses pressurized mercury.

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**10.** All mercury related HSE concerns must be covered in the following site safety plans:

- Spill Prevention Control & Countermeasures (SPCC) Plan.
- Industrial Waste Water Plan.
- Emergency Response Plan.
- Waste Management Plan.
- Waste Minimization Plan.
- Chemical Hygiene Plan.
- Air Emissions Plan.
- Respiratory Protection Plan & Cartridge Change-out Schedule.
- Local PPE Plan & Facility PPE Assessment.

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**11.** A detailed site-specific Mercury Safety Plan must be in place (see InTouch for a detailed example). Details requirements relating to the following must be covered in the Mercury Safety Plan:

**a.** PPE Requirements (including for standard operations and additional protection for maintenance and repair).

**b.** Respiratory Protection requirements and cartridge change-out schedules.

**c.** Contamination Prevention (prevention of cross-contamination to other lab areas), including wipe testing for identifying cross-contamination in other lab areas.

**d.** Monitoring and recording of Mercury exposures:

**i.** Exposure levels in exposed personnel (urine and blood), including periodicity of exposure testing.

**ii.** Permanent or Daily monitoring of Mercury vapor in air, inside the Mercury room and immediate exterior areas (in case of Hg contamination outside of the Mercury room) – including fixed and / or portable devices.

**e.** Applicable local legislation / regulations affecting the industrial use of mercury.

**f.** Air Quality control & monitoring, including ventilation and / extraction (fumehood requirements, including maintenance and testing / calibration of fumehoods, air-flow requirements, etc), air purification, air filtration and emissions requirements. Air quality records must be kept.

**g.** Mercury Disposal requirements & procedures for changing out and disposing of spent fume hood filters and other mercury contaminated wastes (i.e.: disposable PPE, glassware, etc).

**h.** Separation of Mercury from other fluids (settling devices for post-analysis separation of contaminated waste-water, etc) and testing requirements for industrial waste water.

**i.** Requirements for labeling & storage of Mercury.

**j.** Mercury lab temperature control requirements (including fixed and / or portable monitoring devices and alarms / warning systems).

**k.** Mercury lab access control requirements.

**l.** Special requirements for maintenance of Mercury contaminated equipment, including supplier and / or 3rd party contractor intervention and maintenance / repairs / modifications / upgrades to existing equipment.

**m.** Specific requirements related to spill control, cleaning of spilled mercury and decontamination of mercury contaminated equipment.

**n.** Mercury decontamination requirements (decontamination of equipment and parts being shipped and scrapped).

**o.** Requirements for shipping of Mercury.

**p.** HSE Training requirements for working with Mercury.

**q.** Mercury Room design requirements.

**r.** Mercury room signage requirements.

**s.** A reference to the RSA Mercury Free Initiative (InTouch Content ID 4123996).

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## 7.10 Asset Certification, Maintenance and Quality Control

The standard procedures to purchase, control, maintain, certify and track all Testing Services assets, equipment and parts used to contain or control pressure and flow are specified in Section 2: Equipment Quality Control and Administration.

RITE is the business tool utilized to plan and track all asset maintenance, certification and modification recap implementation.

All pressure containing, sampling and pressure controlling equipment shall have as a minimum, a complete Quality File, a vendor-certified pressure test report, and a valid in-house Annual Survey. All major assets shall have a type approval, or independent review certificate (IRC) by a recognized certifying agency.

Wireline owned sample and pressure equipment should be inspected and pressure tested every year to working pressure and every five years to test pressure.

The Location purchasing the equipment is responsible for checking and identifying all local certification requirements.

Pressure equipment without a Quality File cannot qualify for field or laboratory use.

## 7.10.1 Certification by Manufacturer and Certification Agencies

The manufacturer shall certify all pressure-containing and pressure-controlling equipment at the time of manufacture.

The certification shall be at least a design approval (IRC, DVR, or TA) by a certification agency (Lloyds, DNV, and BV). 10,000 psi and higher-rated equipment shall have individual Certificate of Conformity (COC) by a certification agency. In addition the vendor must certify each set of equipment for adherence to all requirements in Schlumberger procurement specifications and applicable codes, and supply a manufacturer pressure test certificate to rated Test Pressure. Duplicate originals of these documents must be filed in the Location Quality File for the equipment set, and originals retained at the manufacturer facility for a minimum period of 5 years. Locations should retain certification documents throughout the useful life of the assets.

“Duplicate originals” are copies stamped “certified true copy of the original”, signed and dated by the responsible manufacturer quality department officer. Local regulations (e.g., NPD regulations in Norway) might dictate stricter certification requirements.

In case of subcontracting (such as Schlumberger Product Centers decentralized manufacturing), the responsibility to ensure availability of documentation rests with the main vendor (i.e., the Product Center).

## 7.10.2 RITE Recording/Quality File

Each pressure containing equipment assembly shall have a Quality File, as described in section 2 POM, containing the following documentation:

- An assembly record itemizing all components by equipment code, serial number or local ID number, date-in-service, description, Working Pressure, Test Pressure, last qualification test.

- Data book, manufacturer certification and traceability records for each item (delivered by the supplier).
- Procurement and movements records.
- RITE history card (compiled by the Location).
- Reception inspection and pressure test record (compiled by the Location).
- Routine inspection and pressure tests records (compiled by the Location).
- Certification renewals as required (delivered by certification agencies).
- Major repairs documentation and certifications (delivered by the repair contractor).
- Traceability records for replaced parts when required (compiled by the Geomarket/Location).
- NDE test records (delivered by the NDE contractor or by the repair contractor).

The Wireline sample chamber quality files consist of the maintenance and testing records maintained in the RITE system, along with the material certification for the primary vessel body which can be found in the on line certification data base (http://pmcert.sugar-land.oilfield.slb.com).

## 7.10.3 Five Year Survey

All certified pressure-containing sampling and analysis equipment shall undergo a Major Re-Certification after five years in service. All certification shall be tracked in RITE and specified in the asset File Code Catalogue.

Re-certification means a detailed survey and performance verification witnessed by (or under control of) a certification agency, leading to re-certification.

The **five-year survey** shall also be carried out **after** replacement of any pressure-containing or pressure-controlling parts.

An **example of Major Re-Certification** requirements for sampling and analysis equipment as defined by one certification agency is given in Table 7-4: Five-Year Survey Requirements. Refer to Operating Procedures and certifying authority regulations for more detailed and complete procedures. In addition refer to section 7.1.1: Test Pressure.

All fluid sampling and analysis equipment pressure retaining parts shall be visually inspected, externally and internally for cracks and surface defects such as pitting and corrosion as part of Major Surveys (CE). If any cracks, pitting or corrosion is detected, the part shall be replaced. The damaged part must be removed from service immediately, red tagged and put into quarantine or junked.

**Table 7-4: Five-Year Survey Requirements**

| Item | Sample Bottles, Core Holders, Pressure Accumu-lators, Inten-sifiers | Sampling Tools | Sampling Manifolds (WSM, etc) | Sampler Carriers | PVT Cells, all pumps, Core Flood Systems, EOR equip-ment, Porosi-meters and other similar Core Analysis Equip-ment containing pressure | Polyaxial and Triaxial Load Frames |
|---|---|---|---|---|---|---|
| Visual inspection | X | X | X | X | X | X |
| Hydrostatic test at test pressure | X | X | X | X | X | X |
| Valve Seat Test at Working Pressure | X | X | X | NA | NA | NA |
| Operational test at Working Pressure | X | X | X | NA | NA | NA |
| NDE Pressure Retaining Parts * | X | X | N/A | X | X | X |
| Review of Quality File | X | X | X | X | X | X |

* Magnetic particle Inspection shall be in accordance with procedures specified in ASTM E-709. Liquid Penetrant Inspection shall be in accordance with procedures specified in ASTM E-165.

Integrity of Wireline sample chambers is the responsibility of Schlumberger Wireline.

Wireline Chambers shall have a detailed inspection and pressure test every five years. The details for this test and inspection are found in InTouch Content ID 4030749. The general flow is shown below.

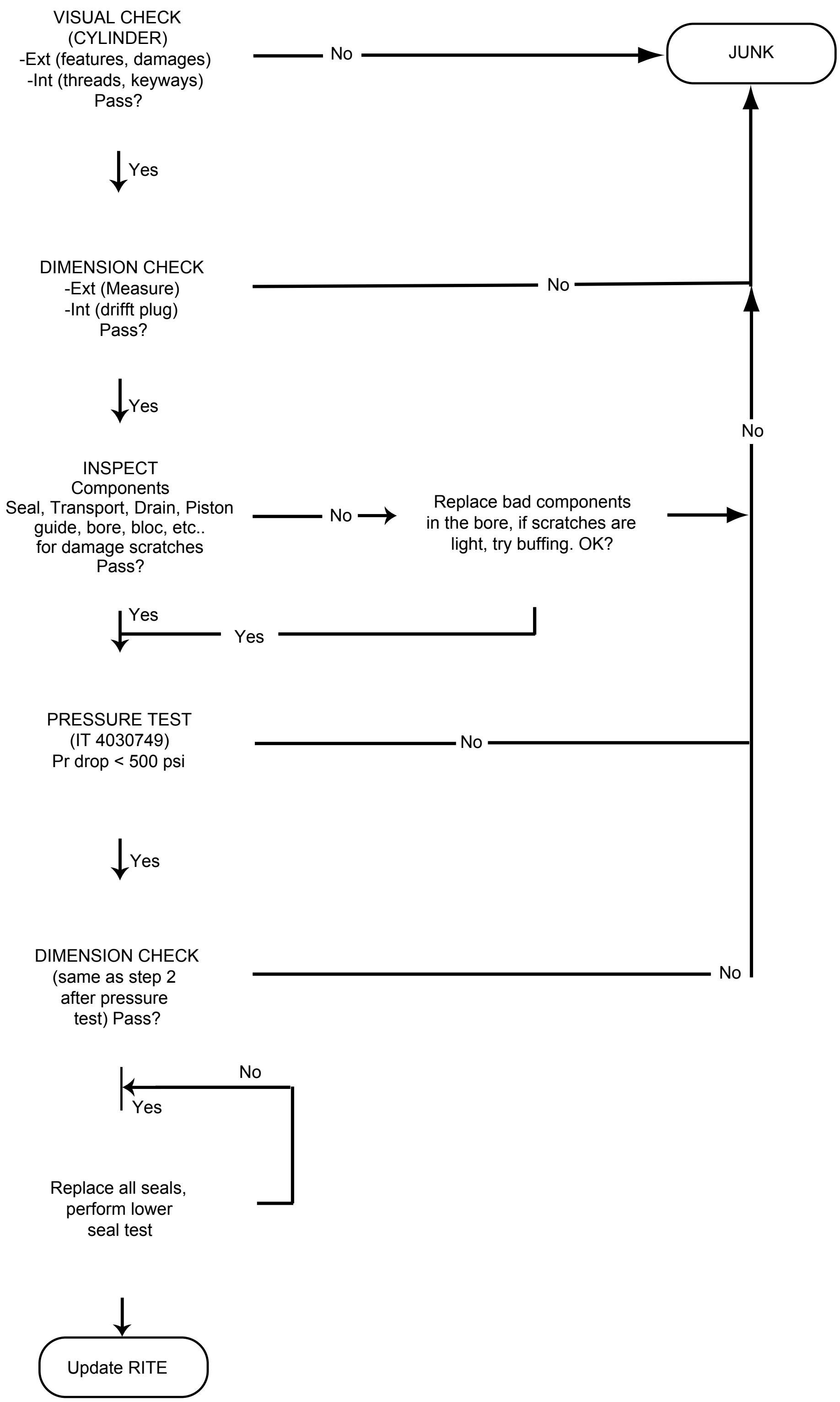


**Figure 7-1: General flow**

### 7.10.3.1 Samples in Sample Receptacles With Expired Major Certification

Reservoir fluid samples may in be storage for periods of time during which the major pressure test certification of the sample receptacle expires.

Sample management and inventory therefore needs to be strictly controlled. If receptacles containing samples are approaching the end of their certification period (i.e. <3 months validity), a proactive approach should be taken by the location with regards to contacting the client and ascertaining the long term management strategy of the sample.

Locations shall manage sample inventory in order to avoid the situation of samples being stored in a non-certified receptacles. The client must always be advised that the certification of any bottle has expired and the long term management of the sample shall be agreed upon between Schlumberger and the client.

In the situation where major certification has expired, the sample bottle can no longer be transported. In addition, no pressure operations/heating shall be performed on the expired bottle until a full risk assessment (HARC) has been completed and appropriate risk prevention and mitigation control measures must be put in place in order to minimize the risk associated with handling a non-certified sample bottle.

Samples in receptacles with expired certification may only be transferred to a certified sample receptacle, atmospheric container or dumped.

Only one transfer operation is permitted from each sample bottle which has expired certification in order to minimize the number and duration of heating and pressure cycles applied to the sample bottle.

Evaluation of metallurgical operating limits for all sample bottles must be carried out prior to any sample transfer or disposal operation as per one of the following two categories below:

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**Caution**
Potential Severity: Light
Potential Loss: Assets
Hazard Category: Pressure

If in any doubt about any pressure equipment metallurgy NACE operating limits contact InTouchSupport.com.

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### Samples within Severe Service Limits

1. For samples in bottles that are **within** sample receptacle metallurgy NACE operating limits, the following conditions apply prior to commencing any work:
    - A job specific risk assessment (HARC) must be completed and risk prevention and mitigation measures in place.
    - An exemption to the TS POM must be raised and approved in QUEST.

### Samples Outside Severe Service Limits

1. For samples in bottles that are **outside** sample receptacle metallurgy NACE operating limits, the following conditions apply prior to commencing any work:
    - An InTouch technical review must be carried out by raising a ticket to consider the proposed transfer on a case by case basis.
    - A job specific risk assessment (HARC) must be completed and risk prevention and mitigation measures in place.
    - An exemption to the TS POM must be raised and approved in QUEST.

## *7.10.4* Routine Inspection and Q-Checks (Annual Surveys)

All Reservoir Sampling and Analysis equipment must be initially qualified by an inspection and hydrostatic test at reception according to RITE TRIM Check procedures and verified at Q-Check (Annual Surveys). The minimum frequency of Q-Checks tests shall be once a year thereafter.

All erosion prone components shall be inspected after every job where sand was produced.

All pressure equipment wetted components shall be inspected after every Severe Service, Extreme Severe Service, HP/HT and Ultra HP/HT operation.

These Surveys must be recorded in the asset Quality File, following the rules set forth in Section 2.1: Scope and Responsibility of the POM.

Detailed Surveys instructions for TRIM and Q-Checks are contained in the relevant asset RITE File Codes, and within validated Maintenance Manuals and Operating Procedures on InTouch. All TRIM and Q-Checks shall be tracked in RITE.

**Q-Check general procedures are as follows:**

- Clean thoroughly all components.
- All threads and sealing surfaces shall be cleaned with wire brush or fine emery cloth.
- All threads and sealing surfaces shall be checked for damage.
- All valves shall be disassembled, to inspect all parts for damage or corrosion. All damaged parts shall be replaced.
- All rupture disks shall be replaced.
- All fluid sampling and analysis equipment pressure retaining parts shall be visually inspected, externally and internally for cracks and surface defects such as pitting and corrosion as part of routine inspections (TRIM) and Q-Checks (Annual Surveys). If any cracks, pitting or corrosion is detected, the part shall be replaced. The damaged part must be removed from service immediately, red tagged and put into quarantine or junked.
- All equipment dimensions shall meet engineering tolerances as specified in the equipment operation and maintenance manuals. If information is not available, contact InTouchSupport.com for clarification. See InTouch Content ID 4859890 for information on postjob/prejob tool inspection and cleaning. A defect zero tolerance attitude must be taken for all parts of all sampling tools. At all times during the cleaning process, keep a close eye and check by feel for any scratches, pits, cracks or other such mechanical damage defects that may prevent the tool from operating correctly. If a pit is visible or if a scratch has depth or if the surface finish on sealing areas is non compliant to 32Ra (Roughness Number), scrap the part and replace with new.
- X-ray inspection or ultrasonic inspection can be carried out instead of disassembly and visual inspection for certain components.
- After inspection and re-assembly, the equipment shall undergo a hydrostatic body test and an operating seat test at maximum working pressure.
- Pressure tests must be recorded on a calibrated chart recorder and filed in the equipment quality file.

Wireline Sample Chambers must have an annual visual inspection of all pressure containing parts, and an internal pressure test to working pressure. Refer to content InTouch Content ID 4030749. Record the inspection and test results in the RITE System.

## 7.10.5 Major Repairs/Re-manufacture

Local maintenance and repairs of pressure-containing RSA equipment shall be limited to replacement of expendable parts or one-to-one replacement of sub-assemblies. Replacement components and assemblies must have similar or higher level of certification than the items they replace. Repaired equipment must be certified following the guidelines for newly manufactured equipment in section 7.9.2: $H_2S$ operations. De-rating is normally not acceptable. Non-certifiable equipment shall not be repaired, and shall be junked. All maintenance shall be tracked in RITE.

Modifications to any pressure containing equipment is strictly prohibited unless the proposed changes have been reviewed and approved by the appropriate Product or Technology Center or the equipment manufacturer (in the case of equipment purchased from a third party manufacturer). All modifications to pressure equipment must comply to the requirements of the TS POM. Any modifications to pressure equipment must be recorded in the equipment's history file. All pertinent certifications and traceability records must be available and recorded in the equipment history file.

Bottles containing a sample do not require an annual survey but are still required to have their five years certification completed. Bottles that are nearing the end of their five years certification period should have the samples transferred to another bottle with a valid certification.

All maintenance shall be tracked in RITE.

## 7.10.6 Equipment Identification

Each individual sub-assembly of sampling and analysis equipment, shall be identified with the following information:

- Serial number/fixed asset number.
- Working Pressure rating (WP, compulsory) and Test Pressure rating (TP, optional).
- Service type.
- Date of manufacture.
- Maximum and minimum design temperatures (where practical).
- For Wireline Sample Chambers, the information above will be required only on the sample cylinder. Where possible, individual components will be marked with a part number and P.O. number for material tracking.

Depending on the type of equipment, the identification can be on a metal plate, on a permanently attached metal ring, or engraved on a non-critical area of its body (see, e.g., API Specification 6A related to equipment marking).

**Note**
Testing Fluid Sampling and analysis equipment does not need to be color coded to per its assigned Working Pressure. The exception to this is the pipework in the drilling lab in TTK, Salt Lake City.

# 7.11 Equipment Procurement and Supply Guidelines

## 7.11.1 Purchase of New Equipment

Reservoir Sampling and Analysis equipment shall be procured exclusively from Oilphase Product Center, Terratek Technology Center and DBR Technology Center and must comply with the Standards listed in paragraph 7.2.1: General Standards.

InTime is the current business system tool used for CAPEX planning.

Spare seals, pressure fittings, manifolds and hoses should be procured via OneCAT catalog (See Fluid Sampling and Analysis). Spares can also be purchased from Schlumberger Area-approved vendors, provided they conform to this Standard.

The Reservoir Sampling and Analysis Business Manager must approve purpose-built systems necessary to comply with special client requirements prior to committing to a purchase. The request for approval must include complete purchasing specifications. These requests should typically be submitted as a Testing Services Rapid Response (R 1/2 or R3/4) via OneCAT catalog.

Schlumberger Product Development has responsibility for design and sustaining of sampling and analysis equipment).

The Location purchasing the equipment is responsible for checking and identifying all local certification requirements, and specifically requesting the necessary certifications at time of ordering.

Third party equipment purchases must conform to the same requirements as for Schlumberger designed equipment. These must be approved by the appropriate Product Centre by exemption.

## 7.11.2 Reception Control

Before entering into service, all new equipment received by a location from a Product/Technology Center shall be subject to a **Reception Control**, including visual inspection, hydrostatic body test to WP and/or operational function test.

All electronic and electrical equipment shall be subjected to a full function test and all certification shall be checked to ensure it complies to local/wellsite regulations.

Proper identification shall be checked as required in section 2.4.1: Equipment Identification and Marking of this Manual. The equipment shall be receptioned and updated in RITE as per section 2.4.4: Reception Control. The Quality File shall be checked, and any nonconformity with the equipment shall be captured in QUEST with a notification made to the appropriate Technology/Product Centre from the SQ investigation page.

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**Note**

Should the Main Root Cause of any SQ event be believed to be an Engineering or Manufacturing issue the appropriate Technology/Product Centre should always be notified in this way.

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Loaned or transferred-in equipment shall be treated as new equipment and subject to a Reception Control unless the Quality File provides complete information as to the validity of an existing qualification.

## 7.11.3 Rented Sampling Equipment

Renting Sampling equipment such as sample bottles is strongly discouraged. However they may be rented from a rental agency if the policy in Section 2.3.2: Rented Equipment is respected.

## 7.11.4 Client Supplied Sample Receptacles

Sample receptacles given by the client to Schlumberger Testing Services for use shall follow all identification, maintenance and qualification requirements as for Schlumberger-owned equipment as per the POM.

Clients shall remain responsible for equipment supplied occasionally to Schlumberger for operations in clients' wells and on clients' wellsite. If the equipment does not conform to the Testing Services/ Wireline-POM, the client shall be made aware of the reasons for non-conformance. Schlumberger Testing Services personnel shall not operate equipment without documented proof of compliance to the minimum required Schlumberger standards. The Schlumberger wellsite supervisor shall consult with their line management superiors if in doubt of the equipment compliance.

## 7.11.5 Third Party Supplied Sample Receptacles

Reservoir Sampling and Analysis equipment shall be procured exclusively from Oilphase Product Center TTK Technology Center and DBR Technology Center and must comply with the Standards listed in paragraph 7.2.1: General Standards. In the event that sample receptacles need to be procured from third party companies such as Whitey, Swagelok, Hoke etc., they shall follow all identification, maintenance and qualification requirements as for Schlumberger owned equipment as per the POM. An exemption to section 7.11.1: Purchase of New Equipment must also be raised.

# 7.12 Testing Services and Wireline Asset Management

Records shall be precise and comprehensive to permit tracking of each individual item/asset, and relating to its manufacturers Quality File, service, maintenance, certification and modification history as per section 2.4: Asset Management.

RITE is the business system used for asset management in Testing and Wireline.

The Product Centers will maintain the RITE File Code Catalogue (FCC) for all Testing Services Fluids Sampling and Analysis equipment as well as maintain the Modification Recap (MR) database.

Wireline HPS will maintain the RITE FCC for all Wireline Reservoir Sampling and Pressure Equipment as well as maintain the Modification Recap (MR) database in RITE.

Refer to RITE Project Resources hub for details and a link to the RITE reference page in InTouchSupport.com.

For details regarding Asset Certification and Asset Maintenance see sections and 2.5: Asset Maintenance - RITE of the TESTING / WIRELINE POM.

# 7.13 Personnel Certification

## 7.13.1 Testing RSA Certification Requirements

All RSA operations involving pressure shall be performed exclusively by RSA personnel who are POM Level 3 (SAM-L3) pressure certified or who are deemed competent and are under direct supervision of an individual who is POM Level 3 (SAM-L3) pressure certified. This applies to any wellsite, workshop, laboratory, client facility or any other location that the pressure operations are performed at. In order to become POM Level 3 (SAM-L3) pressure certified for Fluid Sampling and Analysis operations, an individual must:

- Complete and pass the online **TS-RSA-POM** quiz.
- Attend and pass Compass course for Fluid Analysis or Fluid Sampling, or Pressure Operations Course (released 2014).
- Prove hands on competency under direct supervision in the laboratory, workshop or at the wellsite on a minimum number of jobs or tasks.

Explanatory details can be found within iLearn.

In addition to the above, Field Specialists, Field Engineers and PVT Laboratory personnel must be $H_2S$ trained as per $H_2S$ Standard SLB-QHSE-S015, for any operation where $H_2S$ is expected.

All personnel working in facility with any RSA field operations or laboratory must be POM Level 1 pressure certified in QUEST (general awareness). This certification ensures that all employees are aware of the dangers and risks that are encountered within the facility where pressure is used during operations, but does not permit them to perform pressure operations.

# 7.14 Section 7 Revision History

For more details see Appendix F.

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**Warning**

Potential Severity: Serious
Potential Loss: Security
Hazard Category: Human

The controlled source document of this manual is stored in the InTouch Content ID 3045666. Any paper version of this standard is uncontrolled and should be compared with the source document at time of use to ensure it is up to date.

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# Testing Services Perforating Services

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# 8 Testing Services Perforating Services

This section covers guidelines pertaining to the use of perforating equipment like perforating guns, firing heads and explosive accessories. Under this definition, we cover all Schlumberger-operated equipment containing explosives used for perforating services within Testing Services. Refer to Section 6: Downhole Equipment for perforating equipment that does not contain explosives.

Perforating equipment has been included in this standard due to the applications involving pressure at surface and the increased complexity of modern completions.

Any deviation from the guidelines listed herein requires an exemption as per the Management of Change and Exemption Standard (SLB-QHSE-S010).

## 8.1 Overview

All downhole perforating equipment used by Schlumberger shall be pressure-rated. Since the equipment is subjected to different external and internal pressure, the rating must be specified as collapse, burst or differential. Unlike wellhead and surface equipment, completion equipment is typically specified by ratings with little to no safety factors and without consideration for combined loading. During the application design suitable safety factors for each design case; pressure testing, deployment, installation and use must be selected.

In a system assembly of different components, the rating of the weakest component gives the overall rating of the system. To define the effective maximum allowable pressure one has to consider the function and position in the string of each tool, whether it contains atmospheric chambers and the applied mechanical loads.

Perforating equipment is rated by calculation and tested during design verification. Pressure testing of individual components is generally not performed during manufacture or assembly. The choice of perforating equipment depends on the requirements of a particular completion; to provide appropriate equipment for hostile operations advanced planning is required.

## 8.2 Standards and Specifications

Perforating and auxiliary downhole equipment designed by Schlumberger Testing Services comply with internal Schlumberger design standards and specifications that vary dependant on the application and service of the equipment. There are few industry-accepted standards applicable.

- API 5CT Specification for Casing and Tubing is a standard commonly used to define the rating of other completion components - Pup Joints, casing, etc., that are used with TCP equipment.
- API RP67 Recommended Practices for Oilfield Explosives Safety defines industry accepted rules for explosive devices.
- 8C Specifications for Drilling and Hoisting Equipment (PSL1 and PSL2) is used for Lifting equipment.

Ratings of Schlumberger supplied equipment are published on equipment and product datasheets.

## 8.3 Job Design and Well Integrity

Maintaining the integrity of a well is paramount in delivering a safe, high quality, service to our clients. In addition to following all the measures required to maintain the integrity of individual tools (such as maintenance, certification and traceability of critical parts), at the wellsite the overall Well Barrier Envelope must be established and maintained, and in order to do this all jobs where perforating is to be performed, especially CIRP jobs, must be designed and planned in accordance with POM section 3.2: Job Design, and Planning Well Barriers. The roles and responsibilities of each member of the crew must also be assigned, and this must take into consideration their levels of training and competence.

## 8.4 Equipment Selection

Pressure is only one of several critical parameters used to select perforating equipment; time, temperature, fluids and mechanical loading must also be considered to avoid pressure related failures.

The effect of a pressure failure on perforating equipment may result in a flooded gun or crushing of the gun carrier. This, in turn, may cause a low or high order detonation causing injury, damaging the completion and potentially damaging the well.

Ratings of Schlumberger guns include both pressure and the conditions in which they are shot.

Hostile environment precautions must be followed whenever HNS explosives systems are used. These procedures are documented in the High Pressure High Temperature (HPHT) Gun Systems section of the TCP Field Operating manual. Specialized HPHT equipment may be required. The conditions that determine the selection of HPHT gun systems cannot be clearly defined. Whenever downhole conditions exceed any one of the following conditions: 330 degF [165 degC], 15,000 psi and 100 hr; consult with the Product Center via InTouchSupport.com.

Specialized HPHT hardware, TCP accessories, firing heads, detonators, fill subs, guns, adapters and handling equipment are designed with Peek backups, end to end transfer systems and high load adapters for increased reliability. Standard perforating hardware cannot be adapted to meet these requirements.

## 8.4.1 Service Type

Perforating equipment is not manufactured from materials rated for $H_2S$ service. Materials selected to meet NACE specifications cannot survive the forces generated during perforating. Upon specific request, specialized $H_2S$ accessories may be purchased (e.g., SXAR Release housing, Debris Sub and other flow wetted components).

## 8.4.2 Lifting Subs

Schlumberger shall only use certified lifting subs, manufactured by Schlumberger Technology Center or by approved vendors, for picking up downhole perforating hardware. The use of lifting subs of unknown rating and origin shall be avoided.

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**Note**

The use of third party C-clamps designed for grooved adapters must be fit for purpose and certified by an independent recognized third party (i.e., DNV) in accordance with API Specification 8C. They shall be recertified on a yearly basis and documentation maintained as per API Specification 8C in a dedicated quality file for each clamp.

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Equipment without the required Quality File and updated qualification checks shall not be used for field operations.

## 8.4.3 O-rings

O-ring seals are essential components of all perforating systems. The product centers are continually researching and developing suitable O-ring compounds for extreme conditions and hostile environments. Refer to published seal guidelines for current recommendations. Seal performance is affected by the elastomer choice and the mechanical design:

- **Guns:** The HT3 95 durometer Viton O-ring compound is qualified for use in standard guns up to 350°F and in HPHT gun designs with backups up to 400°F.
- **TCP Accessories and Firing Heads:** The Viton 95D Parco/Parker O-ring compound is qualified for use to 330°F, 15,000 psi and 100 hr. This compound is provided in the standard TCP redress kits.

Above these conditions, elastomer selection and hardware design must be managed on a case-by-case basis. Consult with the Product Center via InTouchSupport.com.

- **Arctic O-rings:** Contact the Schlumberger Technology Center via InTouchSupport.com for recommendations and ordering information.

Perforating hardware O-rings are subject to static and dynamic conditions and the selection of O-ring will affect the frictional forces within the tools, this has a direct impact on the operational values and correct function of tools. For applications below 2000 psi, refer to the appropriate maintenance manual and the TCP FOM for minimum operating pressures and low-pressure assembly procedures.

The completion fluids have a critical impact on elastomeric seals additional qualification testing or hardware selection may be required. Refer to published seal guidelines for fluid compatibility.

Only O-rings and back-up rings qualified by Schlumberger Technical centers for Testing Services perforating product applications shall be purchased for field use, no substitutes shall be used at anytime.

The O-ring compounds qualified for perforating are specifically designed for the oil industry and are compatible with normal well fluids. They have special resistance to attack by refined chemicals and gas invasion.

O-ring compounds deteriorate in the presence of ultraviolet light (sunlight), ozone, radiation, heat and moisture. O-rings must be stored in airtight opaque bags, in cool (less than 120°F), dry locations.

The discard (ie disposal) date for a packet of unused O-rings should be printed on the packet label by the manufacturer. This date refers to a packet which remains sealed, and once the packet is opened the O-Rings must be used as soon as possible. The discard date printed on the packet will generally follow the schedule given in Table 2-3 in section 2.5.7: Shelf Life of Elastomer O-Ring Seals and in any case must always be observed. Limits for the maximum shelf life of O-Rings which are stored in open packets is also given in the table.

# 8.5 Pressure Operations

There are four circumstances where pressure is encountered during perforating operations:

- **Wellhead Pressure:** Coiled Tubing Perforating Services and Slickline Perforating Services.
- Surface pressure testing of perforating equipment both during assembly and on the wellsite.
- Downhole pressure test (Bottom Hole Assembly Test).
- Trapped pressure seen when retrieving the perforating equipment to surface.

## 8.5.1 Wellhead Pressure

Pressure control equipment is used to perform operations safely when pressure at the wellhead is present or may develop during the job (e.g., Coiled Tubing Perforating, Snubbing and Slickline operations).

A routine pressure job does not exist. Every operation performed against pressure presents potential safety hazards. Well-trained personnel and properly maintained equipment are prerequisites for all pressure jobs.

### 8.5.1.1 Coiled Tubing and Snubbing Operations

Field operations involving the use of wellhead pressure control equipment, where explosives devices are subjected to pressure on surface, require special considerations. Snubbing and Coiled Tubing Pressure Operations combine the complexities of wireline perforating operations with those of TCP.

The range of perforating devices include perforating guns, cutters, punchers, pipe recovery devices, chemical cutters and setting tools.

Operations with hydraulic firing heads and pressure at surface have additional risks.

The client may require to deploy long lengths of perforating guns against wellhead pressure.

Pressure testing of the lubricator and gun deployment into the pressurized well is the most critical factor to consider. Procedures must follow WS QHSE Std 22: Coiled Tubing Operations, InTouch Content ID 3313710 attached Guideline 04 Coiled-Tubing Perforating, which includes specific guidelines for perforating operations and additionally the TCP Field Operations Manual.

Perforating services performed with hydraulic firing heads, in wells where the firing head is exposed to surface pressure, require specific job preparation and coordination. Only firing systems specifically designed for operations with surface pressure may be used.

The only pressure initiated firing heads that may be used for Coiled Tubing and Snubbing operations with any exposure to surface pressure are the eFire, CBF and BCF firing systems. Using a solid ball seat, or running the firing head with the ball installed in the seat, is not permitted.

The following key guidelines should be considered and implemented in each Coiled Tubing Perforating job in which surface pressure testing is involved:

- Initial wellsite pressure test must be performed without any tool containing explosives. See Guideline 04 Coil Tubing Perforating reference, attached to WS QHSE Std 22: Coiled Tubing Operations (InTouch Content ID 3313710).
- Hydraulic Firing Heads (CBF and BCF) must be tested to 1.2 times maximum surface pressure expected at anytime during deployment BEFORE being connected to the gun.

Perforating guns shall not be pressure tested. After installing the guns, the pressure control equipment should be equalized to run in hole.

When pressurizing equipment containing explosives, redundant and properly calibrated pressure gauges must be used. Always use the highest-read pressure of the redundant gauges as the WHP.

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**Note**

A perforating gun shall never be exposed to more than 80% of its pressure rating at surface. For third party guns used by Schlumberger, the limit is 50% of their pressure rating.

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A Quick Test Sub is required to test the final connection of the Pressure Control Equipment without pressurizing the perforating device. This device allows the final connection to be tested without applying pressure to the Perforating system.

### 8.5.1.2 Slickline Perforating

Pressure testing of the lubricator and gun deployment into the pressurized well is the most critical factor to consider. Procedures must follow the requirements below and under Section that includes specific guidelines for perforating operations.

The well site Test Pressure (TP) shall never exceed the Schlumberger equipment Working Pressure (WP) rating or the client wellhead WP rating; whichever is lower. See Section for selection of equipment according to its WP rating.

Perforating Services performed with hydraulic firing heads, in wells where the firing head is exposed to surface pressure, require specific job preparation and coordination. Only firing systems specifically designed for operations with surface pressure may be used.

The only firing head (while connected to a perforating device at surface) that may be used for slickline operations with surface pressure is the eFire firing head.

The TCF mode heads that may be run are HDF, BHF, IFSU / EFIRE, Jar Down Head and ProFire firing heads.

On slickline perforating jobs, where surface pressure tests are involved, the following key guidelines should be considered and implemented in each job plan.

- Initial wellsite pressure test must be performed without any tool containing explosives.
- Hydraulic firing heads must be tested to 1.2 times maximum surface pressure expected at anytime during deployment BEFORE being connected to the gun.

Perforating guns shall not be pressure tested. After installing the guns, the pressure control equipment should be equalized to run in hole.

Whenever pressurizing equipment containing explosives, redundant and properly calibrated pressure gauges must be used. Always use the highest-read pressure of the redundant gauges as the WHP.

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**Note**

A perforating gun shall never be exposed to more than 80% of its pressure rating at surface. For third party guns used by Schlumberger, the limit is 50% of their pressure rating.

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To test the final connection of the Pressure Control Equipment without pressurizing, the perforating device a Quick Test Sub is required. This device allows the final connection to be tested without applying pressure to the perforating system.

### 8.5.1.3 Quick Test Sub

The Quick Test Sub (QTS) is designed to avoid perforating equipment being exposed to excessive surface pressure, and also to save rig time, while pressure testing connections of the Wireline or Coiled Tubing Surface Pressure Control Equipment.

For more details refer to CIRP, Well Services, or Wireline Technical documentation. Also search OneCat or In Touch for the keyword “Quick Test Sub.

### 8.5.1.4 CIRP Deployment Stack

The CIRP deployment stack is designed to allow the deployment and reverse deployment (recovery) of long tool strings into a live well. The function of the deployment stack is to facilitate the connection and disconnection of the CIRP connectors under pressure. It is **NOT** designed to close in and/or seal the wellbore.

It is classified as surface equipment and is typically installed above a set of WL or CT BOPs which in turn are mounted above the production tree. It is therefore category 1.1 pressure containing equipment (see POM section 1.7.1: Category 1) and must conform with Testing Services POM requirements.

The deployment stacks are designed to API 6A PSL3 and manufactured to the specifications given in Well Intervention QHSE Standard 02: Coiled Tubing Operations. As a result the pressure rating shall be in accordance with Well Intervention QHSE Standard 02: Coiled Tubing Operations, InTouch Content ID 5884296. Pressure testing shall be in accordance to Testing Services POM Section 4.5: Wellsite Equipment Pressure Testing unless covered by an exemption.

Maintenance must be performed in accordance with RITE program, Testing Services and Wireline POMs, and the OEM inspection and certification guidelines.

**Note**

It is vital for Well Integrity that only trained personnel and verified competent by the TCP Engineer or Technician, operate the CIRP deployment stack.

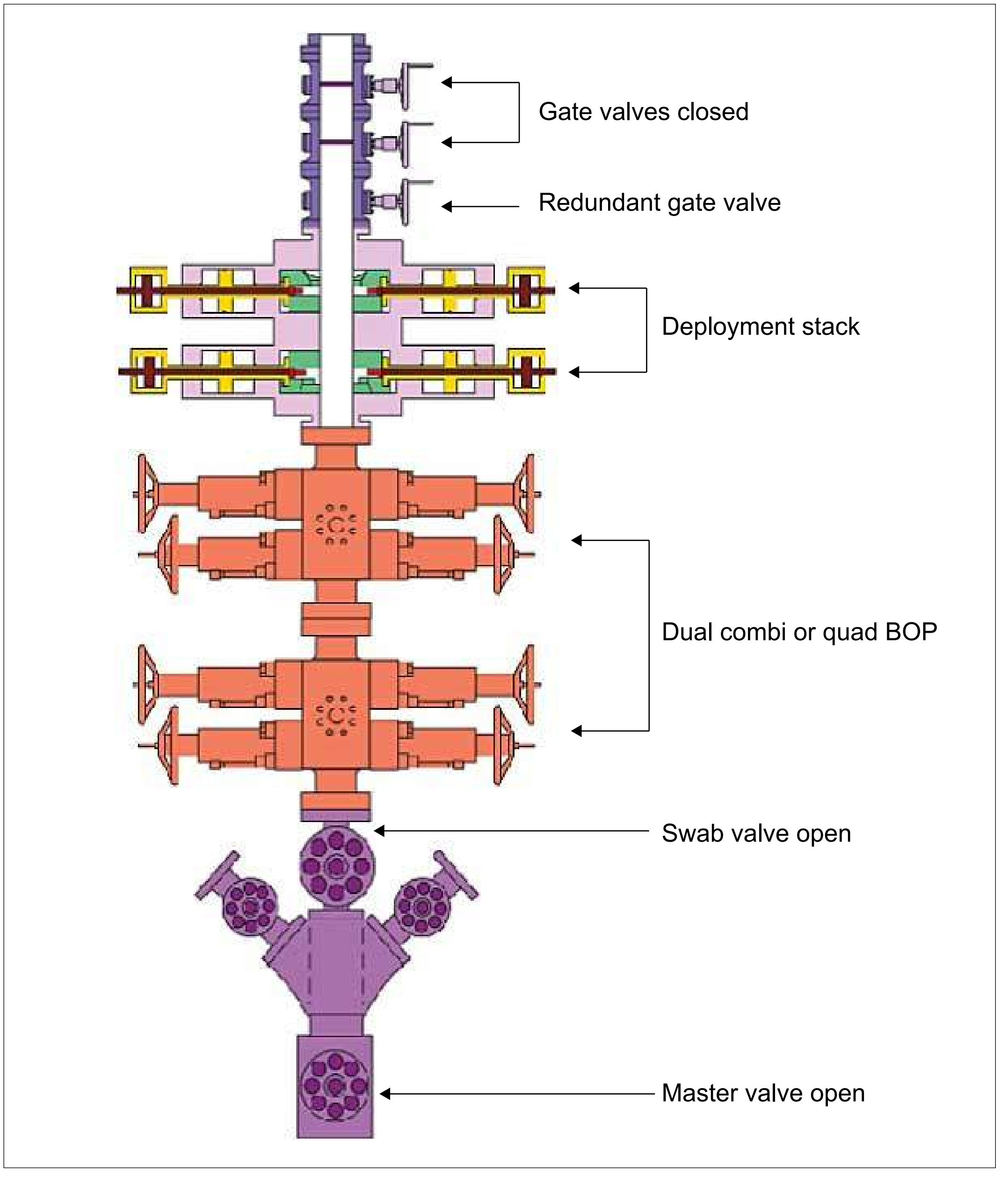


**Figure 8-1: Depicting Basic Deployment Stack Configuration**

## 8.5.2 Pressure Testing of Perforating Equipment

### 8.5.2.1 Equipment Containing Explosives

It is a common practice to pressure test components at surface either prior to or during wellsite assembly.

Pressure testing of any device (e.g., tubing puncher, perforating gun, SXAR, CTAR, MAXR, SXPV, SXVA, jet cutter, etc.) containing explosives is not permitted except as defined in Section 8.5.1: Wellhead Pressure, Section 8.5.1.1: Coiled Tubing and Snubbing Operations and Section 8.5.1.2: Slickline Perforating.

### 8.5.2.2 Equipment Not Containing Explosives

Perforating equipment that does not contain explosives is considered as downhole equipment and therefore the pressure testing regulations set out in Section 6.5: Pressure Testing apply.

Pressure testing of any perforating equipment should never be performed without reference to the appropriate technical documentation.

## 8.5.3 Pressure Testing Downhole

Perforating systems like guns, firing heads, etc., are impacted by the pressure history of the completion process. To minimize risks, repeated pressure cycling, testing of perforating systems must be avoided. This is achieved by both completion design and procedures. The use of multi-cycle pressure firing heads is advised where pressure cycling cannot be avoided.

In-hole pressure test planning must include a leak off path to avoid pressures being built up and affecting perforating equipment placed below a leaking pressure barrier (i.e., packer un-set and rams open, TFTV bypass port open).

## 8.5.4 Trapped Pressure Occurrence

Trapped pressure may occur wherever there is a closed volume in which gas can accumulate. The presence of elements such as various materials, debris, high fluid density or solids concentrations, high temperature and LCM materials can contribute to the occurrence of trapped pressure. The most likely places in our gun system are:

- Between firing head adapter and safety spacer upper intermediate adapter.
- Inside safety spacer below a plugged upper intermediate adapter.
- Inside unloaded, blank sections between perforated carriers.
- Inside an expended, perforated carrier and a plugged upper intermediate adapter.
- Between plugged perforation exit holes in expended carrier.

Fluid trapped under pressure in spacers and in partially fired guns presents a safety hazard to people on the rig floor when breaking down the gun string. Refer to the TCP FOM for trapped pressure procedures.

# 8.6 Procurement

## 8.6.1 Purchase of New Equipment

Equipment approved for purchasing is listed in the InTime catalog. Requests for special or purpose built equipment, crossovers, special adapters and connections, and CIRP deployment connectors, are to be submitted to Rapid Response by means of a OneCAT RFQ. These items shall only be purchased through the OneCAT RFQ process. Any location wishing to purchase CIRP equipment must consult with the In Touch TCP helpdesk prior to placing orders.

## 8.6.2 Rented/Third Party/Client Equipment

Refer to the Explosive Safety Manual (ESM) Section 4 (InTouch Content ID 3010562).

## 8.6.3 Reuse of Equipment (SRC)

Equipment without the required Quality File and updated qualification checks shall not be used for field operations.

# 8.7 Product Certification and Quality Control

General guidelines for quality control of perforating and auxiliary downhole equipment products.

## 8.7.1 Quality Plan

There are some specific industry standards covering downhole products such as safety valves and oilfield tubulars.

To ensure safe and quality assured operations, Schlumberger has set its own standard for all other downhole products.

The specification, material traceability, acceptance tests and pressure test records are all defined and controlled by the manufacturing quality plan and the environmental quality testing performed during design verification.

Specific client quality requirements shall be managed through variations to the manufacturing Quality Plan, additional Quality Verification called “Critical Well” can be requested at the time of the quotation through OneCAT. Critical well procedures can be accessed via Intouch Content ID 2023889.

Downhole products procured from a third party vendor shall have a manufacturing quality plan.

## 8.7.2 Reception, Inspection and Testing of Products

All downhole products must be initially verified by an inspection at reception. This may require pressure testing or function testing of the product as defined by the product operating manual.

## 8.7.3 Major Repairs/Remanufacture

Local field maintenance and repairs of pressure-containing or pressure-controlling downhole equipment shall be limited to replacement of expendable parts or one-to-one replacement of subassemblies. Replacement components and assemblies must have similar or higher level of certification than the items they replace. It is recommended that a Quality Plan be prepared for all major repairs.

Any machining or welding repairs (called “re-manufacturing” in API documents) shall be carried out exclusively by the manufacturer, by vendors approved by the manufacturer or in approved refurbishment centers. Welding must comply with ASME/NACE/API specifications as applicable. Repaired equipment must be re-qualified.

Crossover thread re-cut is allowed following the requirements set out in Appendix C.1: Regional Manufacturing.

**Note**
Approved Regional Manufacturing Facilities or any other approved sub-contractor that is listed by Schlumberger as suitable. In all cases any rework carried out must be recorded in the quality file and updated in RITE.

### 8.7.4 Equipment Identification

Each product shall be identified as per the manufacturing quality plan.

## 8.8 Personnel Certification

All perforating operations shall be performed by pressure qualified personnel as per Section 9: Testing Services Personnel Qualification and Administration.

All perforating operations shall be performed by explosive qualified personnel as per the Explosives Safety Manual (InTouch Content ID 3010562).

The perforating field personnel must have a valid QHSE passport with valid perforating and pressure certificate to conduct perforating operations. Perforating certification will include pressure certification.

TCP personnel must also have basic awareness and knowledge for the other equipment in associated disciplines (Surface Well Testing, Coiled Tubing, Wellhead, etc.)

All TCP operations shall be performed exclusively by pressure-qualified crews. The perforating specialist must be explosives and pressure certified. These certifications are obtained either online or following an Xpert or advanced TCP School at European Learning Center (ELC).

### 8.8.1 Explosives Certification

Explosives or equipment containing explosives to be handled exclusively by trained and qualified personnel. Engineers, field technicians, shooters, drillers, operators, drivers, helpers, gun loaders and all personnel in direct or indirect contact with explosives shall become qualified through certifications organized and conducted by training centers within the GeoMarket.

It is compulsory for any crew performing an operation using explosives, being involved in the preparation, maintenance or completion of an operation with explosives, being involved in the handling, storage or transportation of explosives, be certified for the operation concerned.

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**Note**

If the person has not been certified for the specific operation concerned, they may proceed only under continuous direct supervision of a person qualified in that operation.

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Explosive certification can be obtained as part of a formal course within the Compass training program or by attending a dedicated training course within the GeoMarket and satisfactorily completing a standard quiz. Approval of the content of these certifications is required by the GeoMarket QHSE Manager.

Additional certification may also be required by local regulatory agencies for personnel handling explosives (e.g., Blasters/Users License). This certification is generally necessary for Reservoir Evaluation (Seismic) crews, but may be required for all explosives users and possibly supervisors. The field engineer and field technician training programs for both wireline and testing operations include transportation training, Explosives Safety (NEST), Gun Shop Safety and Perforating Qualification Testing. Successful completion of this training fulfills the explosives certification requirements of many regulatory agencies.

Additionally, the “break-out exam” may satisfy the requirements for a “training exam”. A crew shall be considered qualified if the supervisor has a Level-2 qualification (one-man minimum) and 50% of the remaining crewmembers hold a valid Level-1 qualification. In most countries around the world, local policies exist concerning certifications for personnel handling explosives. If a conflict between local and Schlumberger policies is found, the most stringent policy shall always prevail. In case of a contradiction to Schlumberger policies, the Explosives Safety Committee will lead the investigation and make any decisions, which may result in a change to our explosives policies.

### 8.8.1.1 Explosives Certification Procedures - Operating Personnel

The field personnel must have a valid QHSE Passport with valid explosives certificate to conduct explosive operations. The certificate shall be obtained and maintained as described below.

### *8.8.1.2* Level-1 Explosives Certificate

Employees in direct or indirect contact with explosives (assistants, operators, helpers, gun loaders, drivers, shipping personnel) must follow a specific work-training program to be qualified. The training program must include the following steps:

- Attendance at a formal training session organized through the QHSE Manager, covering General Explosives, Explosive Operations, Loading, Pre-job Preparations and Explosive Safety Rules.
- Pass a standard quiz with at least 80% score. Participate in a minimum of three operations under continuous direct supervision of a qualified supervisor to become familiar with the equipment or procedure.

After completion of these tasks, the employees' QHSE passport shall be updated by the Location Manager. The Level-1 certification and copies of the training qualifications shall be kept in the person's training file.

### *8.8.1.3* Level-2 Explosives Certificate

A certificate will be issued separately for each category of personnel handling explosives (field engineer, technician-shooter, blaster and driller) when the following has been achieved:

1. Pass the basic explosives course curriculum, organized by a local training center within the GeoMarket.
2. Completed a minimum of six months field experience under the direct supervision of a competent engineer, technician-shooter, blaster or driller.
3. Acting as “trainee supervisor” in at least three operations demonstrating the person’s ability to handle explosives and to supervise the operation, while under continuous direct supervision of a qualified engineer, technician-shooter, blaster or driller.

The certificate will be forwarded to the Location Manager who will validate the certificate after the candidate has attended the required operations. The QHSE passport of the employee is updated for Level-2 only after Step 3 has been completed and copies of the training qualifications kept in the person’s training file.

### 8.8.1.4 Coil Tubing Certification

TCP personnel involved in coil tubing operations must have reviewed the online training for Well Intervention QHSE Standard 02: Coiled Tubing Operations, InTouch Content ID 5884296 and pass the online test and maintain valid certification as specified in section 8.8.1.5: Certification Validity.

### 8.8.1.5 Certification Validity

The maximum validity of any certificate is two years from the date of issue. If the employee has not participated in a minimum of one operation during the last twelve months, the employee must perform one operation under direct supervision.

### 8.8.1.6 Re-Certification

Re-certification is accomplished by satisfactorily passing a standard quiz for the appropriate certification level. Additionally, if the employee has not participated in a minimum of one operation during the last twelve months, they must also complete one operation under direct supervision.

### 8.8.1.7 Personnel Currently Performing Explosive Operations

Schlumberger operating personnel currently performing explosive operations without a valid explosive certificate can obtain the certificate by following the same procedure as outlined in Section 8.8.1.6: Re-Certification.

### 8.8.1.8 Third-Party Personnel

Both short and long term third party operating personnel shall be considered nonqualified and must meet the same qualifications as employees before performing their duties unsupervised.

The only acceptable exception to this rule is if the third party personnel working for an equipment rental agency operate only the equipment they supply and provided the rental agency certifies their proficiency on this equipment in writing.

### 8.8.1.9 Administration and Responsibilities

Tracking employee's qualifications is the responsibility of the GeoMarket. It is also the responsibility of the Location Manager/Project Manager to ensure crews operate with a valid explosive certification. It is the responsibility of the employees to keep their certification current as indicated in their QHSE passport.

## 8.9 Section 8 Revision History

For more details see Appendix F.

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**Warning**
Potential Severity: Serious
Potential Loss: Security
Hazard Category: Human

The controlled source document of this manual is stored in the InTouch Content ID 3045666. Any paper version of this standard is uncontrolled and should be compared with the source document at time of use to ensure it is up to date.

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# Testing Services Personnel Qualification and Administration

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# 9 Testing Services Personnel Qualification and Administration

The guidelines discussed herein address personnel qualification and administration for pressure operations. These guidelines are consistent with the Pressure Equipment Standard (SLB-QHSE-S014), the Well Integrity Standard (SLB-QHSE-S022) and the QHSE training proficiency guideline as per the Training and Competency Standard (SLB-QHSE-S005).

The Pressure Equipment Standard (SLB-QHSE-S014) requires that equipment containing well pressure and/or well flow be "operated exclusively by trained and qualified personnel." Therefore it is compulsory for any personnel performing an operation or maintenance step involving pressure to be pressure certified for the operation concerned.

The Training and Competency Standard (SLB-QHSE-S005) establishes the training proficiency guideline. This Standard requires QHSE training to be tracked by certifications defined by "subject or risk topic", "proficiency level" and a "validity period" (see Table 9-1: SLB QHSE Training Proficiency Guidelines). From this standard, the proficiency levels 2 and 3 are defined as:

- Level 2 - Advanced, systems implementing. Demonstrates a comprehensive understanding. Can operate independently without any significant errors.
- Level 3 - Expert, system managing. Demonstrates a mastery understanding. Can operate under all conditions and can supervise and train others at previous levels.

A Testing Services pressure certification includes technical training course(s), a theoretical quiz and practical jobs and/or tasks under supervision. The Testing Services wellsite pressure certifications are further defined as follows:

| Certification Level | Requirements |
|---|---|
| **Pressure Level 2 Certification (previously Basic)** | For Wellsite Personnel<br>For maximum allowable working pressure up to and equal to 10,000 psi.<br>For maximum flowrates up to 30 MMSCF/D gas and/or 8000 bpd liquid. |
| | For Maintenance, Shop and Base personnel.<br>For function checking and pressure testing of equipment of all pressure ranges in the workshop or test bay. |

| | |
|---|---|
| **Pressure Level 3 Certification (previously Advanced)** | For Wellsite Personnel<br>For working pressure above 10,000 psi.<br>For flowrates above 30 MMSCF/D and/or 8000 bpd liquid. |

It is mandatory for FQC's, EIC's, and FSM's who review SDP worksheets and approve job designs to have current Online Certification for the service being reviewed and/or approved. While it is recognized that this does not grant full certification due to jobs not being performed, it ensures line management are up to date with POM and SDP revisions and InTouchSupport.com alerts.

Pressure certification(s) for all Testing Services operating personnel shall comply with this Testing Services Pressure Operations Manual, the Pressure Equipment Standard (SLB-QHSE-S014), the Well Integrity Standard (SLB-QHSE-S022) and the QHSE training proficiency guideline as per the Training and Competency Standard (SLB-QHSE-S005).

In addition to the pressure certifications discussed herein, all operating personnel must be $H_2S$ certified as per the $H_2S$ Manual for any operation where $H_2S$ is expected (Hydrogen Sulfide Manual, InTouch Content ID: 4082472).

Any deviation from the guidelines listed herein requires an exemption as per the Management of Change and Exemption Standard (SLB-QHSE-S010).

## 9.1 Pressure Certification Procedures

All personnel working with Testing Services equipment at the Wellsite or during Maintenance at the shop or base, must have a valid QHSE Passport with valid pressure certification to be able to conduct pressure operations. The certification shall be obtained and maintained as described herein.

iLearn is a training and career development tool used to track and manage wellsite operating personnel's pressure certification.

A wellsite crew shall be considered qualified if:

1. The multi-disciplinary supervisor(s) and each discipline leader (day and night) are certified as per the requirement described in the relevant discipline POM section.
2. At least 50% of the remaining crew members also hold a valid certification. Crew members not holding a valid certification must be qualified by having completed, at a minimum, Pressure Level 1 training.

Maintenance, Shop or Base personnel shall become certified for shop operations pressure duties as per Section 9.1.8: Pressure Certification Procedures - Maintenance Work Shop or Base Personnel.

Anyone not certified for the specific operation concerned shall not be allowed to proceed without continuous supervision by a certified engineer or technician.

## 9.1.1 Pressure Level 2 Certification

Discipline explicit Pressure Level 2 Certifications will be valid when the following has been achieved:

- Pass technical training course(s) as defined in iLearn for specified discipline certification.
- Pass the applicable theoretical on-line certification quiz.
- Perform minimum of jobs and/or tasks under supervision as per discipline specific certification requirement(s).

Table 9-2: Pressure Level 2 Certifications provides a listing of Pressure Level 2 certifications that are available at the time of publishing of this manual. All wellsite and maintenance personnel pressure certifications must be managed through ILearn (https://www.personnel.slb.com/people/Home.cfm?Do=Learning).

## 9.1.2 Pressure Level 3 Certification

Discipline explicit Pressure Level 3 Certifications will be valid when the following has been achieved:

- Has a valid Pressure Level 2 Certification for applicable discipline.
- Pass advanced technical training course(s) as defined in iLearn for specified discipline certification.
- Pass the applicable theoretical on-line certification quiz.
- Perform minimum of jobs and tasks under supervision as per discipline specific certification requirement(s).

Table 9-3: Pressure Level 3 Certifications provides a listing of Pressure Level 3 Certifications that are available at the time of publishing of this manual. All pressure certifications must be managed through iLearn.

## 9.1.3 Certification Validity

All pressure operations certifications are valid for a maximum period of 2 years.

In order to maintain a valid certification, personnel must have completed at least one job within the last 12 months. If personnel holding a Pressure Level 2 Certification or Pressure Level 3 Certification have not participated in jobs for which she/he is certified over a period of one year, personnel must perform one job under a qualified supervisor.

For Maintenance, work shop, or base personnel, the pressure testing and function testing of one tool are considered to constitute one job.

Personnel holding a valid Pressure Level 2 or 3 Certification for wellsite operations are automatically certified for shop pressure testing unless other shop charging or testing certifications are applicable.

## 9.1.4 Re-Certification

Before a certification has expired, personnel must complete the following to obtain a new certification:

- Pass the theoretical quiz for the appropriate discipline and certification.
- Have performed a minimum of one job during the last 12 months. If a job has not been performed within the last 12 months, personnel must perform one job under supervision. For Maintenance, work shop, or base personnel, the pressure testing and function testing of one tool are considered to constitute one job.

Re-certifications for wellsite personnel including the theoretical quiz and practical jobs and/or tasks are managed on-line through iLearn. Additionally job experience should be recorded through the appropriate tab in FTL.

Upon completion of recording these requirements in iLearn and management confirmation thereof, personnel are automatically re-certified.

Maintenance, Work Shop or base personnel shall obtain required pressure Re-certifications as outlined in Section 9.1.8: Pressure Certification Procedures - Maintenance Work Shop or Base Personnel. If not tracked in iLearn, maintenance experience may be tracked from the Assigned To & Done By field of the RITE Work Order.

## 9.1.5 Mid-Career Hired Field & Maintenance Personnel

Mid career hired wellsite personnel shall be considered as non-qualified for pressure operations. They shall obtain the required pressure certifications as outlined in Section 9.1.1: Pressure Level 2 Certification with the exception of the applicable technical training course (Learning Centers, Technology Centers or preferred location training) when it can be demonstrated by CV's (Curriculum Vitae) and references that their knowledge and experience is sufficient.

The Pressure Level 3 Certification (SWT, DST, WHE, SAM) can be achieved only by passing the advanced training course(s) and fulfilling the requirements as outlined in Section 9.1.2: Pressure Level 3 Certification.

Maintenance, Work shop or base personnel shall obtain required pressure certifications as outlined in Section 9.1.8: Pressure Certification Procedures - Maintenance Work Shop or Base Personnel.

Any deviations for mid-career hired personnel minimum training requirements listed herein must be reviewed on a case-by-case basis by way of the Management of Change and Exemption Standard (SLB-QHSE-S010) to be approved in QUEST by Area, Region and/or Sub-Segment Operations and QHSE Support.

## 9.1.6 Existing Field & Maintenance Personnel

Existing personnel who are not already certified under the requirements set out in this chapter of the POM should follow the same procedure as new-hires in Section 9.1.5: Mid-Career Hired Field & Maintenance Personnel.

Any deviations to Existing Field & Maintenance Personnel minimum training requirements listed herein must be reviewed on a case-by-case basis by way of the Management of Change and Exemption Standard (SLB-QHSE-S010) and must be approved by Area/Segment Operations Support.

## 9.1.7 Third Party Personnel

All third party hired operating personnel shall be considered as non-certified until the following conditions have been satisfied:

- Pass applicable theoretical on-line certification quiz in iLearn, or, if the third party personnel concerned do not have access to iLearn, pass a written quiz of questions which are applicable to the duties which they will be performing. The questions for any such written quiz must be based on the contents of the POM, and must be compiled by the SQC or FQC responsible for the location and reviewed by the Geomarket QOSM for suitability prior to them being used for the certification of third party personnel. The written answers to the quiz must be checked by the SQC / FQC and the EIC / FSM, and then filed for future reference.

- Provide demonstration of jobs and tasks proficiency. This may be in the form of a CV (Curriculum Vitae) with references for a minimum of two certification applicable jobs within the last 2 years. One of the jobs must have been completed within the last 12 months.

Third party hired operating personnel shall be certified for wellsite operations upon completion of the theoretical on-line quiz and demonstration of jobs and tasks proficiency as outlined above.

An exception to the requirements above is allowed for third party personnel operating their own equipment provided the third party supplier (third party personnel's employer and supplier of referenced equipment) certifies their personnel's proficiency in writing and provides references for a minimum of two certification applicable jobs within the last 2 years. One of the jobs must have been completed within the last 12 months.

Any deviation requires an exemption as per Management of Change and Exemption Standard (SLB-QHSE-S010) to be approved in QUEST by Area, Region and/or Sub-Segment Operations and QHSE Support.

## *9.1.8* Pressure Certification Procedures - Maintenance Work Shop or Base Personnel

Maintenance, Work shop or base personnel must follow a specific work-training program to be pressure certified. Listed below are the requirements for shop or base personnel pressure certifications including existing field personnel, new hired senior maintenance personnel (mid-career hired) and third party personnel.

The shop or base personnel pressure certification training program must include the following three steps:

1. Familiarization with the equipment and procedures through participation in maintenance and pressure test under supervision.
2. Attendance of a formal training session (which may be administered locally) covering equipment maintenance, pressure-testing procedures and specific technical instruction relating to the equipment installed in the test bay and the family of equipment normally test bay.
3. Experience gained through participation in a series of pressure tests and maintenance operations for a minimum of three months.

The Area, GeoMarket and/or Location have the responsibility to develop and implement the specific training programs suitable for the location.

Formal technical training courses for maintenance of equipment are run by the Learning Centers and Technology Centers and these are tracked in iLearn. Additionally, Areas, Geomarkets, or Locations may administer courses to address specific technical or language needs. However these are not currently tracked in iLearn.

Upon completion of the training and development program, the Location Management staff who normally supervise local staff training will issue a certificate qualifying shop personnel for pressure testing.

The certification title shall be:

**Pressure Level 2 Work Shop Certification**

Pressure Level 2 Work Shop Re-certification requirements must include:

- Location management review of qualifications.
- Personnel to have performed a minimum of one job (function and pressure test of a piece of equipment) within the last 12 months.
- Personnel to participate (attend or provide practical instruction) in a formal training session (which may be administered locally) covering maintenance general maintenance, pressure-testing procedures and specific technical instruction relating to the equipment installed in the test bay.

Certifications are valid for a maximum period of 2 years.

Personnel holding a valid Pressure Level 2 Work Shop Certification are not certified for wellsite operations.

## 9.1.9 Pressure Certifications Tables

**Table 9-1: SLB QHSE Training Proficiency Guidelines**

| Level | QHSE Level Name | Systems | Knowledge Guideline/Description |
|---|---|---|---|
| 0 | Basic | Knowing | Limited theoretical knowledge. Cannot complete basic practical tasks without significant assistance and coaching. |
| 1 | Intermediate | Understanding | Complete theoretical knowledge. Cannot operate independently. |
| 2 | Advanced | Implementing | Comprehensive understanding. Can operate independently without any significant errors. |
| 3 | Expert | Managing | Mastery understanding. Can operate under all conditions and can supervise and train others at previous levels. |

| Level | QHSE Level Name | Systems | Knowledge Guideline/Description |
|---|---|---|---|
| 4 | Leader | Creating/Defining | Mastery understanding. Can operate under all conditions and can design or invent new concepts related to the topic. |

**Table 9-2: Pressure Level 2 Certifications**

| Discipline | Description |
|---|---|
| SWT-L2 | “Pressure Level 2 Surface Welltest Certification” - Pressure certification for SWT (equipment operation) for maximum allowable equipment working pressure up to and equal to 10,000 psi and/or maximum flowrates up to 30 MMSCF/D gas and/or 8000 bpd liquid. |
| SS-L2 | “Pressure Level 2 Subsea Certification” - Pressure certification for 10 kpsi wellhead pressure operations (1.2 x Max WHP < 10,000). WP of equipment may be greater than 10 kpsi but the maximum potential WHP must not exceed 10,000 psi (e.g., 15 k WP rated equipment used on a 10 k job). |
| DST-L2 | “Pressure Level 2 Drill Stem Testing Certification” - Pressure certification for DST, Sub-surface, Subsea (equipment and operation, except sampling).<br>< 10 kpsi WP. |
| MNT-L2 | “Pressure Level 2 Maintenance Certification” - Pressure certification for Surface and Downhole Mechanical Maintenance personnel covering all pressure ranges, but is not valid for wellsite operations. |
| | “Pressure Level 2 Work Shop Certification” - Pressure certification for work shop or base personnel covering all pressure ranges. Not valid for wellsite operations. Not required to be tracked in iLearn. |

**Table 9-3: Pressure Level 3 Certifications**

| Discipline | Description |
|---|---|
| SWT-L3 | “Pressure Level 3 Surface Welltest Certification” - Pressure Certification for SWT (equipment, design and operation) for working pressure above 10,000 psi and/or flowrates above 30 MMSCF/D and/or 8000 bpd liquid. |
| DST-L3 | “Pressure Level 3 Drill Stem Test Certification” - Pressure Certification for DST (equipment, design and operation) for working pressure above 10,000 psi. |
| WHE-SL-L3 | “Pressure Level 3 WHE-SL Certification” - Pressure Certificate for WHE (equipment and operation) Braided/Stranded line, liquid seal head. |
| SAM-L3 | “Pressure Level 3 Fluid Sampling and Analysis Operations” - Pressure Certification for Oilphase wellsite fluid sampling and lab analysis operations. |

## 9.1.10 Deepwater Certification

The "TST-Deep Water-Level 1".certification has been deployed in iLearn and is open to GR11 field supervisors meeting the selection criteria as explained in the Deepwater Training Guidelines.

More information on the Deep Water and Special Projects (DW&SP) program itself can be found under the Schlumberger DeepWater Hub page available at the following address: http://www.hub.slb.com/display/index.do?id=id3294050.

Requirements to have a certified DW&SP supervisor in charge of Deep Water projects is part of the Testing Services Quality Plan and it is now mandatory to assign a certified DW&SP supervisor to Deep Water jobs.

Deep Water job definition: a Testing job with 3 or more disciplines (from SWT, TDA, DST, TCP, SLSS, MPFM), performed on board of a floating rig (semi-submersible or drillship).

This is irrespective of the water depth or the SLSS control system used. Any deviation to this requirement will require an exemption to be filled in Quest. The location FSM should create the exemption, first approver will be the Geomarket Operations Manager, and final approver is the area Vice President.

To ensure proper tracking of the exemptions and of the DW&SP supervisors needs, it is recommended to notify from Quest the HQ Deep Water Projects Manager as well.

## 9.1.11 TCP Pressure Certification

TCP personnel who hold explosive certification as specified in section 8.8.1: Explosives Certification, certification under Well Intervention QHSE Standard 02: Coiled Tubing Operations, InTouch Content ID 5884296 as specified in section 8.8.1.4: Coil Tubing Certification and performed a minimum of 3 pressure jobs or pressure test tasks under supervision shall be considered pressure certified.

# 9.2 Well Integrity Certification

Well Integrity Certification is mandatory for all Testing Services personnel working directly or indirectly on wells or with well Barrier elements. They must complete the Generic QUEST Training SLB-QHSE-S022 (Well Integrity) level 1 training.

In addition, Testing Services personnel who are involved with the design or supervision of jobs where Well Barrier Elements are utilized, are required to complete the Segment Specific QUEST Training TS Well Integrity Level 2.

# 9.3 Administration and Responsibilities

It is the responsibility of each certified personnel to keep his/her certification up to date and ensure the current status is maintained in iLearn (if applicable) and their QHSE Passport.

Technical training course(s), theoretical quizzes and practical jobs and tasks under supervision are recorded through iLearn for wellsite operations certifications (Pressure Level 2 Certification or Pressure Level 3 Certification).

The Area, Region, GeoMarket and/or Location have the responsibility to track the specific training program suitable for the Location/GeoMarket/Region/Area shop or base personnel (Pressure Level 2 Work Shop Certification). Job experience may be proven by reference to the "assigned To & Done By" field on RITE Work Orders.

# 9.4 Section 9 Revision History

For more details see Appendix F.

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**Warning**
Potential Severity: Serious
Potential Loss: Security
Hazard Category: Human



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# Wellhead Pressure Control Equipment

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# 10 Wellhead Pressure Control Equipment

For Wireline Wellhead Pressure Control Equipment please refer to the Wireline Pressure Operations Manual at In Touch Content ID 3046294.

For Slickline Wellhead Pressure Control Equipment please refer to the Slickline Services Pressure Operating Manual at InTouch Content ID 5670619.

## 10.1 Section 10 Revision History

For more details see Appendix F.

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**Warning**

Potential Severity: Serious
Potential Loss: Security
Hazard Category: Human

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# Pressure Test Bays

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# A Pressure Test Bays

## A.1 Generalities on Pressure Tests

Regular "in-house" pressure tests for pressure-containing and pressure-controlling equipment is required. Such pressure tests shall be carried out in specially designed enclosures called "pressure test bays".

A periodic pressure test to a Test Pressure greater than the maximum allowable Working Pressure is the industry standard procedure to ensure that equipment can perform in the field with an adequate safety factor.

There are two types of pressure tests:

- Gas pressure tests using inert gases (nitrogen, helium) or air when there is no risk of creating explosive mixtures.
- Hydrostatic pressure tests using water with suitable additives or other non-compressible liquids such as ethylene glycol, Koomey oil, etc.

As pressure tests are carried out to detect hidden flaws in the pressure-containing envelope, there is a possibility of rupture of the bodies or of separation of parts.

The risks during pressure test are:

- Projection of fragments of the equipment or of parts coming loose.
- Liquid jets of small cross section and high velocity.
- Shock waves in the surrounding atmosphere caused by the sudden release of pressure - especially in the cases where gas is being used as the pressure test fluid.

The energy stored during pneumatic tests is much higher than that stored during hydraulic tests. See Table A-1: Examples of Stored Energy during Pressure Tests.

**Table A-1: Examples of Stored Energy during Pressure Tests**

| Equipment | Test Pressure (psi) | With Air (joules) | With Water[1] (joules) |
|---|---|---|---|
| Separator | 1440 | $1.29 \times 10^8$ | 603 |
| 2-1/2 in. twin BOP | 10,000 | $1.24 \times 10^6$ | 4.15 |
| 2-1/2 in. ID riser, 4 sections | 10,000 | $1.39 \times 10^7$ | 46.0 |

[1] All air has been bled off.

**Therefore gas tests are strongly discouraged.** They are to be limited to special cases when absolutely required for certification purposes (such as API 6A PSL-3G), for difficult troubleshooting, or for elements operating with nitrogen gas precharge (e.g., PCTV).

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**Note**

When testing with gas is required, the equipment must be tested with liquid, immediately before the gas test, to a pressure which is at least 1.20 x the maximum gas Test Pressure. When being tested with gas the equipment must be completely submerged in a water pool.

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Since liquids are compressible, metallic bodies elastic and air in large amounts might remain trapped, even tests with liquids present a risk and require precautions.

As a protection, pressure tests should be carried out in special enclosures, called pressure test bays, built to isolate and contain the effect of a sudden failure of the equipment under test. In case a permanent pressure test bay is not available, a temporary protected area must be created as specified in Appendix A.8: Pressure Tests Outside a Test Bay.

## A.2 Pressure Test Bays

The pressure test bay could be constructed without a roof if appropriate risk assessment and HARC are approved by the management. Note that a larger room allows testing of several items connected together, with considerable timesaving. Different construction techniques can be used; recommended design features and equipment are defined in the following paragraphs.

### A.2.1 Construction Details

Pressure test bay construction details are to be found in InTouch Content ID 4454923 “Standardized OFS Pressure Test Bay Design Module".

The content above will address specifically the differences between existing design and new OFS common design as well as possible adaptation of the OFS common design.

Any deviation from the OFS design will have to be evaluated via specific risk assessment and documented within the specific pressure test bay quality book.

## *A.2.2* Pressure Test Unit

The pressure test unit consists of a high-pressure pump (normally air-operated) and a control panel. The high-pressure pump must be located inside the safety enclosure. The control panel is located outside the safety enclosure, close to the viewing hatch or CCTV monitor. It houses the pump controls, a pressure gauge and pressure recorder monitoring the Test Pressure, indicators and safety devices.

Integrated commercial test units are available from several suppliers. They can be used as part of the test bay, if the high-pressure pump and fittings are suitably isolated with protective steel plates.

## *A.2.3* Safety Devices

The door locks should be interlocked with the pump air supply and the pump bleed-off system, so that:

- Initial pressure cannot be applied unless the doors are locked.
- A pressure switch turns on a flashing light or flashing warning sign as soon as pump pressure is applied.
- A safety key arrangement for bypass of the door safety device shall be installed to allow access to the test bay by authorized personnel when the applied pressure is less than or equal to working pressure for the sole purpose of performing function checks.
- The door lock is completely released only when the pressure is totally bled off, preventing access inside the enclosure when the tested piece is under pressure.

Safety shut down system must be installed to prevent pressure from Test Pressure of Equipment by A pressure gauge with limiter linked to the pump supply to turn it off when the preset Test Pressure is reached or any equivalent safety system. The shut down functionality is to be tested after installation and once a quarter thereafter (minimum).

## *A.2.4* Fittings, Liners, and Medium/High Pressure Flexible Hoses

Working Pressure of all fittings, liners, and Medium/High Pressure flexible hoses in the test bay shall be equal to, or greater than, the Test Pressure of the equipment to be tested.

It is therefore recommended to equip all test bays with Autoclave Engineer or similar fittings (corresponding to API Specification 6A, 17th edition section 900, Figure 911) and liners rated 15,000 psi minimum WP for testing 10,000 psi WP field equipment and 22,500 psi minimum WP for testing 15,000 psi WP field equipment.

**Note**

It is acceptable to have 10,000 psi WP field equipment fitted with ¼ inch or ½ inch NPT fitting as this equipment is only taken up to 15,000 psi Test Pressure inside a pressure test bay. Additionally, until end of 2015, fittings used during Q-Check of 15,000 psi DST equipment fall under this exception as this maintenance level shall be performed only inside Pressure Test bay. No more than one pressurized port is allowed at same time. Test Caps are covered in the next section.

Fittings and Needle valves must comply with the requirements of section 4.4.12: Fittings. Liners and medium/high pressure flexible hoses must comply with the requirements of Appendix B.7: Medium and High Pressure Flexible Hoses and Liners.

Use of NPT fittings on 10,000 psi equipment which is being tested to a test pressure above 10,000 psi should be limited to 1 single plug or needle valve per NPT threaded port. Test caps and plugs which are test bay equipment and used for pressure testing equipment to 10,000 psi or above must have autoclave ports for fittings.

## A.3 Adapters, Blanking Plugs and Test Caps

All adapters, blanking plugs and test caps assigned to the pressure test bay need to be considered as **shop only equipment** and must not be used outside the pressure test bay (i.e. wellsite operations). This shop equipment must be clearly marked with:

- Maximum Allowable Pressure
- Part Number
- Serial Number

Unless otherwise noted, this equipment is rated for Standard Service and has a Minimum Design Temperature of -20 degF.

The shop equipment should be Light Grey in color with color band corresponding to pressure rating.

This equipment must have full traceability and must have a Maximum Allowable Pressure rating, or higher than, the **maximum** pressure detailed in the Test Procedure of the equipment to be tested. Remember that the WP or TP of equipment is not given by the type or style of the connections on it - check the data plate or manual. The Testing Services assigned Maximum Allowable Operating Pressure for **Standard Service** Hammer Unions is the CWP rating of the union (eg the Maximum Allowable Pressure Rating of a 1502 Standard Servce Hammer Union is 15,000 psi). Test Caps and Plugs which are test bay equipment and used for pressure testing to 10,000 psi or above must have Autoclave ports for fittings. No welding or local repairs are allowed. A full list of test fixtures referenced with individual serial number and ratings should be kept next to the pressure bay control panel.

## *A.4* Gauges and Recorders

Gauges used on the test unit control panel should have a range such that routine measurements are performed in the 25% to 75% full-scale range. Accuracy and resolution should be at least 0.5% of full scale. Gauges and recorders shall be calibrated at regular intervals according to the manufacturers' specifications. Calibration should never be older than twelve months for any annual or major qualification tests.

## *A.5* Pressure Test Records

Pressure tests shall be recorded versus time using a hard copy device, either a circular plot from a pressure recorder or a hard copy log from a computer device. If a chart recorder is used, it shall be fitted with a clock rotation speed appropriate for the duration of the test. 2 to 4 hour clocks are recommended for the standard 5 to 15 min hydrostatic tests.

Hard copy plots shall be retained in the equipment history file. They should also be scanned and uploaded to the RITE work order. The hard copy plots shall be marked with the following information:

- Identification of equipment tested (all items of equipment shall be listed.)
- Identification of pressure measuring/recording device.
- Type of test (integrity/body test, operational test, Q-Check, Major Re-Certification).
- Test fluid (optional).
- Test Pressure.
- Result of tests and remarks.

- Date of test.
- Name and signature of tester or supervisor.
- Name and signature of third party witness (when required).

A stamp similar to the example in Figure A-1: Pressure Test Chart Stamp can be made and used to ensure all relevent information is captured on the test chart.

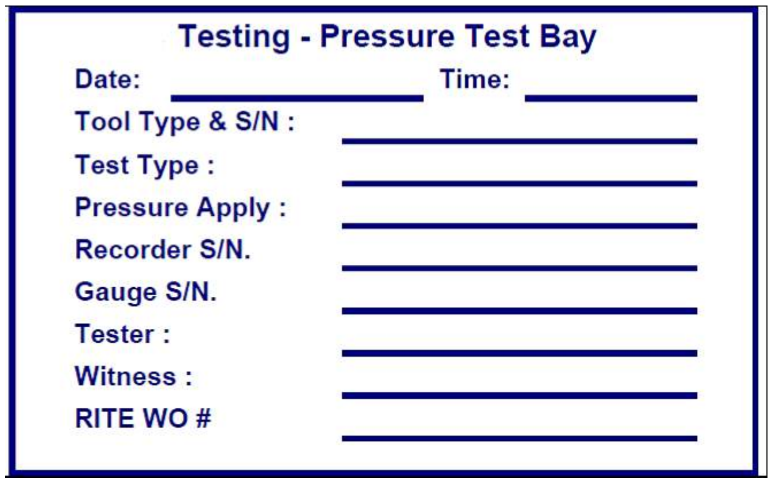
Testing - Pressure Test Bay
Date: ____________ Time: ________
Tool Type & S/N : ____________
Test Type : ____________
Pressure Apply : ____________
Recorder S/N. ____________
Gauge S/N. ____________
Tester : ____________
Witness : ____________
RITE WO # ____________

**Figure A-1: Pressure Test Chart Stamp**

## A.6 Test Bay Quality File

A test bay must have a quality file, containing:

- Manufacturer's bulletins for all test equipment.
- A list of all test fixtures and adapters with their pressure ratings.
- Certification and traceability documents for all the test bay pressure equipment (pump unit, fittings, liners, flexible hoses, adapters, blanking plugs and caps etc.) as required.
- Calibration certificates for the pressure gauges.
- A schematic drawing of the pressure bay setup and of the safety interlocks.
- Detailed test procedures and safety instructions.

Suitably condensed versions of the above should be prominently displayed next to the control panel.

# A.7 Annual Survey of Test Bay

As with all equipment, the test Bay shall be certified for use by an annual survey (Q check). All test fixtures, adapters, blanking plugs and test caps shall be inspected for signs of wear or damage and any defective item shall be disposed of.

The Test bay Quality file must be updated with the inventory of the test fixtures, adapters, blanking plugs, test caps, flexible hoses and liners which are physically present. The pressure circuit (hose/liner end) shall be blanked off and pressure tested to maximum Working Pressure.

The identification / serial numbers of the test fixtures, adapters, blanking plugs, test caps, flexible hoses and liners tested shall be itemised and the results shall be recorded and filed in the test bay quality file. A third party witness of the test is recommended.

# A.8 Pressure Tests Outside a Test Bay

Locations performing frequent pressure tests should have a purpose-built pressure test bay which should be used for all post maintenance, and Annual and Major Survey pressure tests. These tests prove the integrity of the re-assembled equipment and therefore have a higher risk factor than tests performed at the wellsite.

If a test bay is not available (or not large enough to house the equipment, e.g., a separator body test), the pressure test area must be isolated with visible barriers and warning signs positioned at access points and walkways, to restrict movements of unnecessary personnel. The actual size of the isolated area depends on local safety policies. As a suggested guideline, movements should be restricted within at least 50 ft of the equipment to be tested.

When available, the use of adequate blast walls, portable pressure test bays, pressure test enclosures or any other reasonable mean of protection (other equipment, solid concrete walls, etc…) should be considered.

The Test Pressure unit controls must be situated outside the pressure test area. All high-pressure hoses and liners must be secured to avoid “whipping” in case of failure.

From 1st August 2011 it is mandatory to use a roundsling restraint system when pressure testing surface piping and crossovers outside a pressure test bay.

Pressure testing outside a pressure test bay at the base requires the preparation of a HARC and an approved exemption by the management. The following approval levels may be taken as being in line with standard 10:

- Pressure Tests up to WP - Exemption approval must be given by the Location FSM plus the loction or Geomarket Testing services Operations manager.
- Pressure Tests up to TP - Exemption approval must be given by the Testing Services Operations Manager plus the OFS base Manager, or the Operations Manager plus the Area QOSM.
- In either situation the Operations manager may delegate to the Geomarket QOSM, but if this is done the location FSM MUST be in the approval chain.

# A.9 Pressure Testing Procedures

Specific procedures for each type of equipment are to be found in the maintenance manuals.

## A.9.1 Hydrostatic Tests

General guidelines for hydrostatic body tests are as follows:

- Pressure Safety Valves and relief devices must be replaced by blanking plugs before applying Test Pressure. If PSV's are not removed, the maximum applicable pressure is 90% of the rated set pressure of the device. Inadvertent operation of a PSV while testing requires its replacement and re-calibration.
- All air must be bled from the system. This is accomplished by filling the system under test with a bleed-off valve open at the highest point in the system and can be accelerated by using a vacuum pump.
- Any wet parts and spills must be thoroughly dried out so that leaks can be easily detected.
- Test pressure must be introduced slowly, (e.g., increments of 1000 psi) and held for a primary holding period (usually 3 min) after the pressure has stabilized at TP value and the equipment and pressure gauges have been isolated from the source of pressure.
- Pressure is then bled to 0 psi.
- Test pressure is reintroduced and held for the secondary holding period. (Enough time to verify that no leaks are present, usually 15 min of stable pressure recordings with no pressure fall off allowed).
- If the equipment does not hold pressure, locate the leak from behind the protective device.

**Danger**
Potential Severity: Catastrophic
Potential Loss: Personnel
Hazard Category: Pressure

If a leak occurs, do not approach the equipment until pressure is bled off. Under no circumstances should parts be tightened or handled while under pressure, except for the cycling of gate valves when the pressure is equal to, or lower than, WP.

- After a successful hydrostatic body test at TP, all valves are pressure tested at Working Pressure. In areas where low-pressure tests are a requirement, the valve test should be repeated at 300 psi.

For each series of tests, a clearly defined pressure-testing program must be established beforehand and each operator involved in a pretest briefing. A qualified supervisor must be in charge of the operation and must ensure that the testing equipment is fit for purpose, that all pretest checks have been carried out and that the safety procedures are followed.

## *A.9.2* Gas Testing

The following points must be observed when testing with gas.

- The equipment must first have undergone a hydrostatic test to a pressure between 1.2 and 1.5 times the pressure of the gas test which is to be performed. The hydrostatic test must never exceed the Test Pressure of the equipment, and the gas test must never exceed the Working Pressure of the equipment.
- To perform a test with gas, the equipment to be tested must be completely submerged in a tank of water.
- The tank in which the equipment has been submerged must be inside a Test Bay which is constructed in accordance with the requirements of section A.2
- The tests should take place at a temperature which is in the range of 0 – 40 DegC [32 – 104 DegF. (Normal Ambient).
- The tests must be performed using an inert gas, generally Nitrogen. (as specified in API 6A for PSL-3G certification.)
- Any valves or chokes must be in the partially open position when performing a body test.
- When testing valves, the opposite side of the valve to that which is being tested must be open to the water in the tank.

**Note**

For pressure testing with gas, the internal volume of gas should be reduced by use of filler bars whenever possible.

The requirements for the renewal of API 6A PSL-3G certification are as follows:

Body Test – One single test to WP is required. The pressure holding period shall not be less than 15 minutes, and starts only when the equipment and pressure recording device have been isolated from the pressure source.

The acceptance criteria is that there must be no bubbles visible in the water bath during the pressure holding period, and the gas pressure in the equipment must not drop by more than 300 psi.

**Seat Test for Valves –** Two tests are required, one at WP, the other at 300 psi, in each direction for which the valve is designed to hold pressure. (ie Gate valves will generally require a total of four tests, one at WP and one at 300 psi in each direction).

The primary test to WP should be performed first, with the same duration and acceptance criteria as for the body test.

The test pressure should then be bled to zero, before re-pressurizing to 300 psi for the secondary test. The duration and acceptance criteria are the same as for the body and primary tests, except that the maximum allowable drop in test pressure is reduced to 30 psi.

A **Back-Seat** test to WP on the valve stem seals may be performed in conjunction with either the body test or valve seat tests depending on the design of the valve. The area between the primary packing and the back seat, or other means of re-packing the stuffing box, shall be vented during this test.

## A.10 Personnel Certification for Shop Pressure Testing

Each location must have a qualified supervisor in charge of and responsible for the operations in the pressure test bay. This person is typically the Maintenance Supervisor, however the location management may appoint a person specifically for the purpose, or designate another person if no Maintenance Supervisor is available.

Field personnel holding a valid Level 2 pressure certification for wellsite operations are automatically certified for shop pressure testing under the responsibility of the pressure test bay supervisor.

# *A.11* Appendix A Revision History

For more details see Appendix F.

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**Warning**

Potential Severity: Serious
Potential Loss: Security
Hazard Category: Human

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# Surface Well Testing Pipework and Flexible Hoses

# B Surface Well Testing Pipework and Flexible Hoses

## B.1 Scope

The purpose of this standard is to define the specifications and requirements for pipework used by Schlumberger Testing Services for Surface Testing Operations.

This standard is for use primarily by the operating personnel and provides guidelines for the procurement of new equipment or acceptance/rejection of existing equipment.

All pipework used for surface well testing, including those involving client's equipment shall comply with this standard and with applicable regulatory and client requirements, whichever are the highest. For any pipework, it is of vital importance to understand that:

- The pressure rating of the hammer unions does not give the rating of the pipe assembly.
- The pressure rating of any assembled pipework system is not determined by the end connection or the pipe itself, but by the lowest rated section.

Any deviation from the guidelines listed herein requires an exemption as per the Management of Change and Exemption Standard (SLB-QHSE-S010).

The following definitions apply to the equipment described in this standard:

| Term | Definition |
|---|---|
| **Pipework** | All pressure-containing equipment not having any processing or controlling functions (e.g., straight piping, elbows, crossovers, T-pieces, wellhead adapters, flexible hoses). A pipework element is composed of a piping body and of connectors. |
| **Piping Body** | Straight length of pipe or hose or elbow or tee piece, etc. Receiving pipe end connections. |
| **Connector** | Mechanical device enabling an easy (fast) assembling of two adjacent piping sections. A connector comprises two hubs or subs, a nut or clamp and a seal. |
| **Hammer Union** | Connections comprising male end (internally threaded wing nut) and female end (externally threaded stub). The connection is sealed using an elastomeric lip seal or metal to metal seal, sealing is achieved when the wing nut is hammered up tight to the female stub. |

| | |
|---|---|
| **Clamp Connector** | Connector composed of two hubs and of a two-piece clamp. The two piece clamp is secured by bolts. |
| **Sub** | Type of pipe end connection for hammer union. |
| **Hub** | Type of pipe end connection for clamp connector. |

# B.2 Design Standard for New Pipework

## B.2.1 Standardized Pipework Tables

By design sour service hammer unions do not necessary have the same pressure rating as standard service. For example, a sour service 3 inch Fig 1502 union is rated to 10 Kpsi WP, whereas the standard service 3 inch Fig 1502 is rated to 15 Kpsi WP. This is not a Testing Services specification or downgrading but is an industry and manufacturing practice.

All the rigid surface testing pipework used by Testing Services is designed for $H_2S$ Service and only welded or integral pipework design is approved.

Screwed on (threaded) connectors are NOT accepted apart from when used on flexible hoses with a WP of 285 psi or less.

**Note**
Schlumberger Well Services use only standard service treating iron and there must be no interchanging of piping components between the segments.

The specifications of the Surface Well Testing Pipework are summarized in Figure B-1: Standard Pressure Hammer Union Pipework Table, Figure B-2: High Pressure Hammer Union Pipework Table, Figure B-3: Schlumberger Rating for “Grayloc” Clamp Connector Pipework and Figure B-4: Low Pressure ASME Flanged Pipework Table. Two types of pipework are used:

- Pipework fitted with hammer unions (Refer to Figure B-1: Standard Pressure Hammer Union Pipework Table and Figure B-2: High Pressure Hammer Union Pipework Table).
- Pipework fitted with clamp connectors (Refer to Figure B-3: Schlumberger Rating for “Grayloc” Clamp Connector Pipework).

The tables give the following fundamental information:

1. Schlumberger assigned working pressure.

2. Schlumberger assigned color code for easy identification of the pipework working pressure.
3. Schlumberger assigned minimum value of wall thickness, corresponding to the pipework rejection criteria.

---

**Note**

The following tables report the most commonly used piping in Schlumberger. If you have any special application/requirements not covered by these tables, please contact InTouch Surface Well Testing.

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Standard Pressure Hammer Union Pipework Table

| Pipe Nom. Size (in.) | Pipe OD | Pipe Sch. | Pipework Material | Minimum Yield Strength of material (psi) | Minimum Tensile Strength of material (psi) | Design Stress up to 350 degF (psi) | H2S Standard | Nominal Wall Thickness (in.) | Minimum Wall Thickness (in.) | Schlumberger Assigned WP (psi) | Schlumberger Assigned TP (psi) | Color Code |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 206 Piping | | | | | | | | | | | | |
| 6 | 6.625 | 80 | A 106 gr B / A333 gr 6 | 35000 | 60000 | 20000 | NACE MR0175 | 0.432 | 0.241 | 1500 | 2250 | Light blue |
| 602 Piping | | | | | | | | | | | | |
| 3 | 3.5 | 80 | A 106 gr B / A333 gr 6 | 35000 | 60000 | 20000 | NACE MR0175 | 0.300 | 0.208 | 2500 | 3750 | Yellow |
| 4 | 4.5 | 80 | A 106 gr B / A333 gr 6 | 35000 | 60000 | 20000 | NACE MR0175 | 0.337 | 0.247 | 2300 | 3450 | Yellow |
| 1002 Piping | | | | | | | | | | | | |
| 3 | 3.5 | XXS | A 106 gr B / A333 gr 6 | 35000 | 60000 | 20000 | NACE MR0175 | 0.600 | 0.398 | 5000 | 7500 | Red |
| 4 | 4.5 | XXS | A 106 gr B / A333 gr 6 | 35000 | 60000 | 20000 | NACE MR0175 | 0.674 | 0.511 | 5000 | 7500 | Red |
| 6 | 6.625 | XXS | API 5L X52* | 52000 | 66000 | 22000 | NACE MR0175 | 0.864 | 0.690 | 5000 | 7500 | Red |

2” Fig 602 and 2” Fig 1002 are banned and have been removed from the table.
For basis of minimum thickness calculation see Section B.2.2.1.
6” 1002 was previously specified with A 106 gr B or A333 gr 6 material which gave an insufficient corrosion/erosion allowance when the manufacturing tolerance was taken into account. The API 5L X52 now specified is an API material that is not listed in the ASME B31.3 Appendix A and in this case the design stress is the lower of either 1/3 of the tensile strength or 2/3 of the yield, a temperature de-rating factor of 0.9 is also applied.
Pipe and Union Material Operation Temperature Ranges:
• A106 gr B: 32 degF to 350 degF (0 degC to 177 degC)
• A333 gr 6: -20 degF to 350 degF (-29 degC to 177 degC) as standard, or -50 degF to 350 degF (-45.5 degC to 177 degC) subject to Charpy Impact Test at time of manufacture.
• API 5L X52-32 degF to 350 degF (0 degC to 177 degC)
Note: These are the general temperature ranges of the materials. For individual piping temperature range, always refer to the Quality File.
4” Fig.602 SLB working pressure value of 2300 psi is set slightly above the API RP 14E recommended value of 2278 psi, therefore 4” Fig.602 will not be provided with reference to the API RP 14E in the TA/DVR.

**Figure B-1: Standard Pressure Hammer Union Pipework Table**

**High Pressure Hammer Union Pipework Table**

| Pipe Nom. Size (in.) | Pipe OD | Pipe Sch. | Pipework Material | Minimum Yield Strength of material (psi) | Yield Strength at 350 degF* | Design Stress @ to 350 degF (psi) | H2S Standard | Nominal Wall Thickness (in.) | Minimum wall thickness (in.) | Schlumberger Assigned WP (psi) | Schlumberger Assigned TP (psi) | Color Code |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **1502 Piping and elbows** | | | | | | | | | | | | |
| 2 | 2.375 | XXS | AISI 4130 (75K) | 75000 | 67500 | 45000 | NACE MR0175 | 0.436 | **0.237** | 10000 | 15000 | Black |
| 3 | 3.500 | XXS | AISI 4130 (75K) | 75000 | 67500 | 45000 | NACE MR0175 | 0.600 | **0.349** | 10000 | 15000 | Black |
| 4 | 4.500 | XXS | AISI 4130 (75K) | 75000 | 67500 | 45000 | NACE MR0175 | 0.674 | **0.448** | 10000 | 15000 | Black |
| **2202 Piping and Elbows**** | | | | | | | | | | | | |
| 2 | 2.500 | Special | AISI 4130 (75K) | 75000 | 67500 | 45000 | NACE MR0175 | 0.625 | **0.354** | 15000 | 22500 | White |
| 3 | 4.125 | Special | AISI 4130 (75K) | 75000 | 67500 | 45000 | NACE MR0175 | 1.000 | **0.585** | 15000 | 22500 | White |
| 4 | 5.500 | Special | AISI 4130 (75K) | 75000 | 67500 | 45000 | NACE MR0175 | 1.250 | **0.780** | 15000 | 22500 | White |

* After application of temperature derating factor (0.9). For basis of minimum thickness calculation. See section B.2.2.2.

** Fig 2202 piping is banned from operations with the exception of flushing lines. See section B.2.4.4. Crossovers to and from Fig 2202 may still be purchased and used in order to adapt equipment which is fitted with these connections.

Pipe and Union Material Operating Temperature Ranges:
AISI 4130: -20 degF to 350 degF (-29 degC to 177 degC)

Note: This is the general temperature range of the material, subjected to proper charpy test. For individual piping temperature range, always refer to the Quality File.

**Figure B-2: High Pressure Hammer Union Pipework Table**

Schlumberger Rating for "Grayloc" Clamp Connector Pipework

| Pipe Nom. Size (in.) | Pipe OD | Pipe Sch. | Pipework Material | Minimum Yield Strength of material @ 350 degF (psi) | Minimum Tensile Strength of material @ 350 degF (psi) | Design Stress up to 350 degF (psi) | H2S Standard | Nominal Wall Thickness (in.) | Minimum wall thickness (in.) | Schlumberger Assigned WP (psi) | Schlumberger Assigned TP (psi) | Color Code |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Standard Pressure | | | | | | | | | | | | |
| GRAYLOC 3 GR 27 Clamp Size 3_Ring# 27_Hub OD 5 in. | | | | | | | | | | | | |
| 3* | 3.5 | 80 | A106 GrB A333 GR6 | 35000 | 60000 | 20000 | NACE MR0175 | 0.300 | 0.208 | 2500 | 3750 | Yellow |
| GRAYLOC 3 GR 23 Clamp Size 3_Ring# 23_Hub OD 5 in. | | | | | | | | | | | | |
| 3* | 3.5 | XXS | A106 GrB A333 GR6 | 35000 | 60000 | 20000 | NACE MR0175 | 0.600 | 0.398 | 5000 | 7500 | Red |
| GRAYLOC GR 34 Clamp Size 4_Ring# 34_Hub OD 6 in. | | | | | | | | | | | | |
| 4 | 4.5 | XXS | A106 GrB A333 GR6 | 35000 | 60000 | 20000 | NACE MR0175 | 0.674 | 0.511 | 5000 | 7500 | Red |
| GRAYLOC 6GR52 Clamp Size 6_Ring# 52_Hub OD 6.625 in. | | | | | | | | | | | | |
| 6 | 6.625 | XXS | AISI 41XX (60K) | 54000 | 76500 | 25500 | NACE MR0175 | 0.674 | 0.602 | 5000 | 7500 | Red |
| High Pressure | | | | | | | | | | | | |
| GRAYLOC D 31 Clamp Size D_Ring# 31_Hub OD 6.75 in. | | | | | | | | | | | | |
| 4 | 4.5 | XXS | AISI 41XX (75K) | 67500 | 85500 | 45000 | NACE MR0175 | 0.674 | 0.448 | 10000 | 15000 | Black |
| GRAYLOC G52 Clamp Size G52_Ring# 52_Hub OD 6.75 in. | | | | | | | | | | | | |
| 6 | 6.75 | Special | AISI 41XX (75K) | 67500 | 85500 | 45000 | NACE MR0175 | 0.875 | 0.673 | 10000 | 15000 | Black |
| GRAYLOC C 25 Clamp Size C_Ring# 25_Hub OD 5.50 in. | | | | | | | | | | | | |
| 3*** | 4.125 | Special | AISI 41XX (75K) | 67500 | 85500 | 45000 | NACE MR0175 | 1.000 | 0.585 | 15000 | 22500 | White |
| GRAYLOC C25 Clamp Size C_Ring# 25_Hub OD 5.50 in. | | | | | | | | | | | | |
| 4** | 4.5 | Special | AISI 41XX (75K) | 67500 | 85500 | 45000 | NACE MR0175 | 1.000 | 0.638 | 15000 | 22500 | White |

* The 3" pipe WP 2500 psi and the 3" pipe WP 5000 psi have the same hub diameters (5.0") and use the same clamp sets. However the seal rings are different and an effective pressure seal between these two different ratings of pipe is not possible.

** The 4" pipe WP 15000 psi (pipe OD 4.5") was introduced as a replacement for the 3" pipe with a WP of 15000 psi (pipe OD 4.125") as the 4.125 pipe is a non standard size and difficult to obtain. Schlumberger Testing Services Technology Centres will not process any new orders for the 3" 15000 psi WP pipe, but pipe of this size which is already in the field may be used up to the end of its natural life without being changed.

Pipe and Union Material Operating Temperature Ranges:

- A106 gr B: 32 degF to 350 degF (0 degC to 177 degC)
- A333 gr 6: -20 degF to 350 degF (-29 degC to 177 degC)as standard, or -50 DegF to 350 DegF (-45.5 DegC to 177 DegC) subject to Charpy Impact Test at time of manufacture
- AISI 41XX: -20 degF to 350 degF (-29 degC to 177 degC)

Note: These are the general temperature ranges of the materials. For individual piping temperature range, always refer to the Quality File.

*** Some C25 Grayloc piping 15 kpsi WP previously sold by SRPC does not correspond to the C25 Piping described in this table but have the following characteristics: Nominal Size 3", Pipe OD: 3.500", Nominal Wall Thickness: 0.600", Minimum Wall Thickness: 0.530". This piping can still be used but under the following criteria: A valid Annual Survey, minimum wall thickness => 0.530" and an approved Exemption by Geomarket in Quest.

**Figure B-3: Schlumberger Rating for "Grayloc" Clamp Connector Pipework**

**Low Pressure ASME Flanged Pipework Table**

| Pipe Nom. Size (in.) | Pipe OD | Pipe Sch. | Pipework Material | Minimum Yield Strength of material (psi) | Yield Strength at 350 degF | Design Stress up to 400 degF (psi) | H2S Standard | Nominal Wall Thickness (in.) | Practical Minimum wall thickness (in.) | Schlumberger Assigned WP (psi) | Schlumberger Assigned TP (psi) | Color Code |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ASME 150 RF Flange Piping | | | | | | | | | | | | |
| 8 | 8.625 | 40 | A106 gr B / A333 gr 6 | 35000 | N / A | 20000 | NACE MR0175 | 0.322 | 0.211 | 285 | 427.5 | N / A |
| 10 | 10.75 | 80 | A106 gr B / A333 gr 6 | 35000 | N / A | 20000 | NACE MR0175 | 0.365 | 0.263 | 285 | 427.5 | N / A |

* Due to the low pressure application, the minimum thickness required to contain the pressure is much less than the thickness required to maintain the mechanical strength of the pipe.
The minimum thickness has therefore been calculated using a minimum pressure of 1,000 psi as advised in the note in section B.2.2.1.

** The pressure rating of the ASME 150 # RF flanges decreases with temperature. See section B.2.5.6 for details.

**Caution**: 8" and 10" piping has been designed for relief lines only.
Back pressure calculations are MANDATORY to ensure that the WP will not be exceeded.

Pipe and Union Material Operating Temperature Ranges:

- A106 gr B: 32 degF to 350 degF (0 degC to 177 degC)
- A333 gr 6: -20 degF to 350 degF (-29 degC to 177 degC) as standard, or -50 DegF to 350 DegF (-45.5 DegC to 177 DegC) subject to Charpy Impact Test at time of manufacture.

Note: These are the general temperature ranges of the materials. For individual piping temperature range, always refer to the Quality File.

**Figure B-4: Low Pressure ASME Flanged Pipework Table**

## *B.2.2* Technical Clarifications and Information Related to this Standard

### *B.2.2.1* Welded or Integral Pipework Design

Only welded or integral pipework design is acceptable. The pipework is made either of several sections welded together or as a single section called integral design.

The integral design does not involve any welding. The union's subs (or hubs) are machined as part of the piping, and for a hammer union the wing nut is retained by means of a segment (collet) system to the sub. Since the wing nut can be removed there are safety concerns that wing nuts can become mismatched, it is highly recommended not to use this type of design and use welded connections whenever possible. All new procurement will be with welded connections.

The segment (Collet) system, must be of the design where the 3 collet pieces have integral square shoulders at one end which retain them inside the wing nut of the hammer union, and an external Circlip, acting against the back of the wing nut, holding them in position.

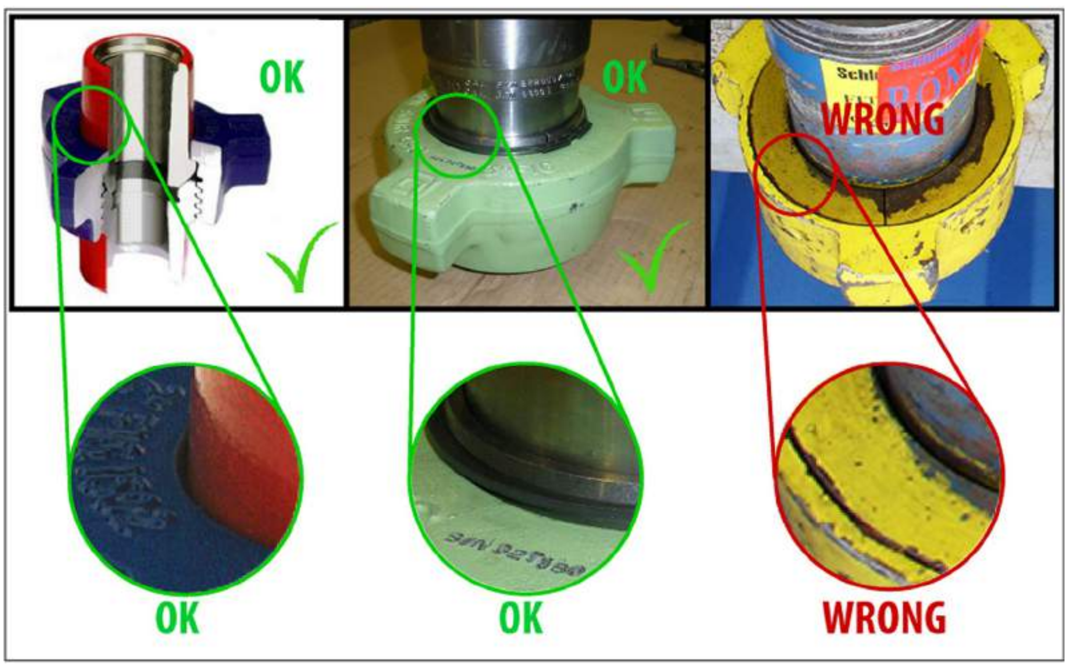


**Figure B-5: Approved Hammer Unions**

**Note**
There is no real benefit in respect of the design strength of integral pipework verses the design strength of welded pipework.

### B.2.2.2 Specifications for Low and Medium Pressure Testing and Production Pipework Components, Complying with API RP 14E/ ASME B 31.3

These components comply with the API Specification 14E/ASME B31.3. Their use is limited by Testing Services to Low or Medium WP, below 5000 psi, used for Category 2 equipment.

They consist in:

- Straight pipe
- Butt-welded elbows
- Butt-welded tees
- Crosses

They are defined by

- Nominal diameter
- Weight class or schedule number
- Material (steel grade)

**Example**
Elbow 3 in., XXH, A234 WPB

#### Actual Diameters

The actual external and internal diameters results from both the nominal diameter and the schedule or weight class.

For a given nominal diameter, the external diameter is fixed and the internal diameter or wall thickness changes. They are determined by the weight class or schedule number; thus, the Working Pressure (WP) changes.

The following pipe weight classes and schedules are typically used:

| | | | |
|---|---|---|---|
| Weight Class | STD | equivalent to | Schedule 40 |

| | | | |
|---|---|---|---|
| | XH | equivalent to | Schedule 80 |
| | No weight class | | Schedule 160 |
| | XXH or XXS | | No Schedule number |

### Low Carbon Steel Grades

Steel grades of production piping are defined according to ASME B-31.3 or API RP 14E and therefore worldwide standardized.

Easily weldable low carbon steels are used:

| Pipework | Steel Type |
|---|---|
| **Straight Pipe** | ASTM Type A106 grade B and A333 Grade 6 Steels |
| **Butt-welded Elbow, Tees, Crosses** | ASTM Type A 234 WPB, A 420 WPL6 Steels |
| **Butt-welded or Integral Flanges or Forged Fittings** | ASTM A 105, ASTM A 420 WPL6 Steels |

All these steels have a Minimum Tensile Strength of 63,000 psi.

Their hardness is less than 22 HRC and is in accordance with NACE MR 0175 requirements.

**Note**
It is impossible to determine the correct steel properties and composition without performing a destructive test on a sample of the material. Such tests fall outside the scope of this document.

## *B.2.2.3* Specifications for High Pressure Pipework Components: Compliance with API Specification 6A

The following components for high pressure pipework (WP equal to and above 5,000 psi) comply with API Specification 6A.

API Specification 6A defines the following parameters and corresponding markings:

- Temperature class

  Identified by one capital letter. One class or the combination of two classes defines the minimum design temperature and the maximum operating temperature as shown in Table B-1: Temperature Class.

- Material class

Identified by two capital letters. The material class is defined by the service type, depending on the type of Fluid:

- AA, BB, CC - are for general service, non $H_2S$, from non-corrosive to moderately corrosive fluids.
- CC, DD, EE, FF, HH - are for sour service ($H_2S$), from non-corrosive to very corrosive fluids.

---

**Note**

The degree of corrosion for a fluid is given by the partial pressure of $CO_2$ (psia). Refer to API Specification 6A.

---

- PSL rating (PR rating)
  - The Product Specification Level corresponds to a level of quality and controls during the manufacturing of the product.
  - From the lower level (PSL1) to the highest level (PSL4).
  - Our pipework is rated:

    PSL2 for 5,000 psi < WP < 10,000

    PSL3 for 10,000 psi WP and 15,000 psi WP

---

**Note**

Level PSL4 is not commonly used except for certain high pressure and/or high risks products.

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- Nominal size or bore size
- Working Pressure

**Example**

6A-P-DD-PSL2-(PR2) - 3-1/16 in. - 10,000 psi

The standardized pipework made of low alloy AISI 41xx steels heat-treated in accordance with NACE MR-0175, correspond to a Material Class DD.

The minimum Tensile Strength is 102,000 psi

Yield Strength is 80,000 psi.

Equivalent Low Alloys steels or Alloys with better tensile properties can be used if they comply with NACE MR-0175.

High Pressure Pipework is used for Category 1.1 and 1.2 equipment. High pressure pipework consists in: Straight pipe, subs, hubs, elbows, tees, crosses, flanges, etc.

**Table B-1: Temperature Class**

| | |
|---|---|
| Class P = | -20 to 180 degF (high pressure pipework) |
| Class P + U = | -20 to 250 degF |
| Class P + X = | 20 to 350 degF |

## B.2.2.4 ASME B31.3 Process Piping, Chapter II, Section 304, Pressure design of Components and basis of Calculation

In accordance with ASME B31.3, Chapter II, Section 304 Pressure Design of Components, thickness calculations are based in the following equation:

**t = P x D/(2 x S + P x 0.8)**

where:

t = thickness in inches D = external diameter in inches P = working pressure

- **t** = thickness in inches
- **D** = external diameter in inches
- **P** = working pressure
- **S** = design stress in psi. This is the lower of either: 1/3 of the minimum tensile strength of the material, or 2/3 of the minimum Yield strength of the material. The material design strengths are given for different operating temperatures in table A-1 of the ASME B31.3 standard.

This is the equation used for all Testing Services piping which has a WP of 5,000 psi or less.

---

**Note**

Although the above equation gives the minimum thickness of piping to contain the pressure, at low pressures the calculated material thickness becomes very thin, and the pipe looses mechanical strength. For this reason, the pressure value entered in the equation should never be less than 1,000 psi. This is especially important when calculating the minimum thickness values for fixed piping on 600 or 720 psi separators, and inlet manifolds on Gauge tanks and Surge tanks.

---

The following is an example of how the minimum thickness would be calculated:

3 in. 1002 piping, Schedule XXS, working pressure 5000 psi, test pressure 7,500 psi

- **D** = 3.5 in.
- **P** = 5000 psi
- **S** = 20,000 psi. (This value comes from ASME B31.3, Table A-1, and is the same from "minimum" to 400 degF).

t = 5000*3.5/(2*20000+5000*0.8) = 0.398 in.

The minimum thickness for this pipe case is therefore = 0.398 in.

## Nominal Thickness

When the pipe used in the example above is delivered, the nominal thickness (Tnominal) is given as 0.60 in.

The manufacturing tolerance is +/- 12.5% of the Tnominal.

The minimum thickness at the time of delivery for a new pipe is therefore = 0.600 in – 12.5% = 0.525 in.

This means that when the piping is new, there is at least 0.525 – 0.398 = 0.127 in of material for corrosion / erosion.

On percentage basis, 0.127 in. would be 24% of the original minimum delivery thickness of 0.525 in.

## *B.2.2.5* ASME B31.3 - High Pressure Piping - Chapter IX - Basis of Calculation

According to ASME B 31.3, High Pressure is considered to be pressure in excess of that allowed by the ASME B 16.5 class 2500 rating for the specified design temperature and material group.

The limit is around 6,000 Psi depending on temperature.

According to the ASME B31.3, Chapter IX, thickness calculations are based in the materials 2/3 (yield strength) at maximum operating temperature.

The equation used for the calculations is the following:

**ASME B31.3 → t = D/2 x [1 - exp (- P/S)]**

t: thickness in inches

D: external diameter in inches

P: working pressure

S: design stress in psi → 2/3 yield strength * Optional Temperature Derating factor Yr

Yr = Temperature Derating factor from API 6A, Annex G, Table G4 (0.9 for AISI 4130 at 350 degF)

This is the equation used for all Testing Services piping which has a WP above 5,000 psi. The following is an example of how the minimum thickness would be calculated:

4 in. 1502 piping, Schedule XXS, working pressure 10,000 psi, test pressure 15,000 psi

D = 4.5 in.

P = 10,000 psi

Yield Strength = 75,000 psi (from Table 6 “Standard material property requirements for bodies, bonnets and end and outlet connections” in API 6A).

S = 45,000 psi → this value comes from 2/3 * (75,000 psi) * 0.9

t = 4.5/2 * [1 –exp (-10,000/45,000)] = 4.5/2*[0.1993] = 0.448 in.

The minimum thickness for this pipe case is therefore 0.448 in.

---

**Note**

The API 6A standard quoted above is the twentieth edition dated October 2010.

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### Nominal Thickness

When the pipe used in the example above is delivered, the nominal thickness (Tnominal) is given as 0.674 in.

The manufacturing tolerance is +/- 12.5% of the Tnominal.

The minimum thickness at the time of delivery for a new pipe is therefore = 0.674 in – 12.5% = 0.590 in.

This means that when the piping is new, there is at least 0.590 – 0.448 = 0.142 in of material for corrosion / erosion.

On percentage basis, 0.142 in. would be 24% of the original minimum delivery thickness of 0.59 in.

---

**Quality Note**

- The use of steels with better characteristics will NOT qualify for a higher Working Pressure (WP) rating or a reduced wall thickness rejection criterion than that is assigned by Schlumberger Testing Services in , and .
- Piping that has a thickness less than the minimum thickness tolerated cannot be pressure down rated, IT MUST BE RENDERED INOPERABLE.

---

New pipework with hammer unions or Grayloc hubs has the Schlumberger assigned assembly working pressure stamped or forged on the union nut or on the Grayloc hub. Older pipework is normally blank.

## B.2.2.6 Thickness Calculations for Pipework Crossovers, Tees, and Laterals etc

Due to the hybrid nature of most crossovers (i.e one end has a different pressure rating to the other) and the subsequent wide range of different materials of manufacture and Working Pressures, standard values for minimum thickness are not available and it is necessary to refer to the Quality File of each individual crossover to help determine what it should be.

Some Quality files will have the minimum thickness value stated in the documentation, but in most cases it will first be necessary to verify the material of manufacture, and then use the appropriate value for the design stress from the table below to calculate a minimum value.

| Material | Minimum Tensile Strength (psi) | Minimum Yield Strength (psi) | Design Stress up to 350 DegF (psi) if used in the Standard Pressure equation (Pipes with a WP of 5 K psi or less) | Design Stress* up to 350 DegF (psi) if used in the High Pressure equation (Pipes with a WP greater than 5 K psi) |
|---|---|---|---|---|
| A105 | 70000 | 36000 | **23000** | **21500** |
| A106 gr B | 60000 | 35000 | 20000 | **21000** |
| A216 WCB | 70000 | 36000 | **23000** | **21500** |
| A217 WC1 | 65000 | 35000 | **21500** | **21000** |
| A234 WPB | 60000 | 35000 | 20000 | **21000** |
| A333 gr 6 | 60000 | 35000 | 20000 | **21000** |
| A420 WPL6 | 60000 | 35000 | 20000 | **21000** |
| API 5L X52 | 66000 | 52000 | 22000 | **31000** |
| API 5L X65 | 77000 | 65000 | **25500** | **39000** |
| API 5L X70 | 82000 | 70000 | 27000 | **42000** |
| API 5L X80 | 90000 | 80000 | 30000 | **48000** |
| API 60K (41XX) | **76500** | **54000** | **25500** | **32000** |
| API 75K (41XX) | **85500** | **67500** | **28500** | **40500** |

**A temperature derating factor (Yr) of 0.9 has already been applied to the design stress figures given for use in the high pressure equation and no further derating is required.*

The values given in the table are in line with those which are to be found in the ASME B31.3 Table A-1.

The minimum thickness of crossovers which have a uniform nominal size (i.e the pipe does not vary in ID or OD) may be calculated using the equations given in Section Appendix B.2.2.1: ASME B31.3 Process Piping, Chapter II, Section 304, Pressure design of Components and basis of Calculation (for crossovers which have a WP of 5,000 psi or less) and Section Appendix B.2.2.2: ASME B31.3 - High Pressure Piping - Chapter IX - Basis of Calculation (for crossovers which have a WP above 5,000 psi).

To be in accordance with ASME B31.3, crossovers which have a change in diameter (ID, OD or both) must have 12.5% additional minimum thickness in order to allow for the increased stresses encountered at the point where the diameters change.

The thickness equations thus become:

t = 1.125 x [P x D / (2 x s + P x 0.8)] for crossovers with a WP of 5,000 psi or less.

and

t = 1.125 x (D/2 x [1 – exp (-P/S)]) for crossovers with a WP above 5,000 psi.

Remember that the Working Pressure rating of the crossover is given by its' lowest rated part, and this lowest pressure rating is the value used to select which pipe equation should be used for the thickness calculation.

It will also be necessary to calculate the minimum thickness for each end of the crossover if there are changes in ID, OD (or both) so that both ends of the crossover can be thickness checked. In the event that OD's are not available from Quality Files, they will have to be measured with a caliper. Measurements will be taken from each end of the crossover where OD's are constant.

It is recommended that a hard copy of the calculation of the minimum thickness values is included in the Quality file if they are not already given in the documentation, and it is further recommended that the minimum thickness values be entered in the "Remarks" section of the RITE equipment card for easy reference.

Tees and Laterals etc. are usually consistent with the specifications in the standard pipework tables, however caution is advised and the Quality Files should be reviewed to ensure that this is the case. If not, then the calculations for minimum thickness will have to be done the same way as for crossovers.

## *B.2.3* Instructions and Rules for Application of the Standard

### *B.2.3.1* All pipework procured shall comply with this Standard

Testing Services Operations Support must approve any procurement of pipework outside of these Specifications.

### B.2.3.2 2 in. Fig 402 Hammer Unions are forbidden

As per API RECOMMENDED PRACTICE 7HU1 and IADC alerts, Schlumberger Testing Services Technology Centers will not process any order for pipework fitted with 2 in. Fig 402 Hammer Unions.

This style of hammer union has never been approved for use by Testing Services.

The 2 in. Fig 402 female sub can mismatch with a 2 in. Fig 1502 male sub.

### B.2.3.3 2 in. Fig 602 Hammer Unions are forbidden

As per API RECOMMENDED PRACTICE 7HU1 and IADC alerts, Schlumberger Testing Services Technology Centers will not process any order for pipework fitted with 2 in. Fig 602 Hammer Unions. This size of 602 union has been banned since the year 2000.

This decision has been taken because several incidents related to the possible mix of 2 in. Fig. 602 with 2 in. Fig. 1502 have been reported.

All equipment with 2 in. Fig. 602 inlet/outlet must be modified replacing the 2 in. Fig. 602 connection by 3 in. Fig. 602 or other (Refer to Appendix C for local repairs).

### B.2.3.4 2 in. Fig 1002 Hammer Unions are forbidden

As per API RECOMMENDED PRACTICE 7HU1 and IADC alerts, Schlumberger Testing Services Technology Centers will not process any order for pipework fitted with 2 in. Fig 1002 Hammer Unions. This size of 1002 union has been banned for a long time because the 2 in. Fig 1002 female sub can mismatch with a 2 in. Fig 1502 male sub.

### B.2.3.5 All Sizes of Fig 2202 Hammer Unions are forbidden

Schlumberger Testing Services Technology Centres will not process any order for pipework fitted with any size of Fig 2202 Hammer Union. This pipework has been banned since 1st January 2011.

This decision has been taken in order to align with industry practice in respect of Hydrocarbon flow lines which should have only metal to metal seals for WP > 10,000 psi.

New 15,000 psi WP surface testing piping and equipment shall be procured with Grayloc metal-to-metal seal connectors.

The use of any existing 2202 piping in flow lines must be approved through the QUEST exemption process (SLB-QHSE Standard #10) with approval at Segment level.

Crossovers to and from fig 2202 may still be used in order to adapt any currently existing Schlumberger equipment which is fitted with these connections, but it is strongly recommended that the flowline inlet and outlet connections are changed (or removed so that the API flange connections are used instead).

Changing the 2202 connections on drain or flushing lines of 15K equipment is not required, but may be done for the convenience of having standardised connections.

2202 piping, or other types of piping with non-metal seals, are still allowed, but only for flushing lines (i.e. lines with intermittent use) connected to sand filters which have a WP above 10K.

### *B.2.3.6* Use of Hammer Unions with threaded Subs

The use of pipework or flexible hoses fitted with Hammer Unions where the male and female subs of the Hammer Union have internal threads which are screwed onto the body of the pipe or hose end piece is forbidden, except for low pressure flexible hoses as defined in Section .

### *B.2.3.7* Use of Schedule 80 Pipework

With the exception of the Schedule 40 pipework described in section Appendix B.2.3.8: Use of Schedule 40 Pipework, all pipework must be manufactured using material which is schedule 80 or greater.

### *B.2.3.8* Use of Schedule 40 Pipework

Schedule 40 piping with Fig 206 connections may only be used on flare booms (due to constraints with flare boom weight limitations) or for relief lines of 8" or larger. It shall not be used at any other point in the rig up.

### *B.2.3.9* Use of Articulated Pipework

Articulated Piping with swivels are forbidden in surface testing operations except under following conditions:

- Articulated Piping may be used during circulation in connection with “Shoot and Pull” operations where no reservoir effluents or gas is routed through this articulated pipework. Only mud/kill fluid is allowed for pumping and reversing through this pipework.
- The standard color-coding must identify all such articulated pipework and additionally, the following must be stenciled in clear letters: **Not for flow of reservoir fluids/gas**.
- The pipe must be 2 in. 1502, 10,000 psi WP.
- It is strictly forbidden to subject the articulated pipework to reservoir driven pressure. Only surface induced pump pressure may be used.
- The rig up must have a check valve installed downstream of the pump and at the very end point prior to connecting to the flowhead.
- The rig up must have a Lo-Torque valve installed immediately downstream of the wellhead return outlet and prior to any articulated pipework.
- The articulated pipework used for such operations must be visually inspected following the guidelines set out in Section and pressure tested to WP at the base prior to each load out.

## *B.2.3.10* Limitations of Pipework fitted with Fig 206 unions

Pipework with Figure 206 hammer unions is rated for a maximum Working Pressure (WP) of 1500 psi.

Figure 206 schedule 80 pipework may be used in the following situations:
- For vent or relief lines when required by PRV outlet size or Architest simulation.
- Downstream of the separator on any job where flowrates require it.
- At any point in the rig up when testing a production well which has a permanent completion installed, and where the maximum possible WHP, either shut in or flowing, including pressure created by any means of artificial lift, does not exceed 1,250 psi. (The 1250 psi limit maintains the standard 1.2 * MPWHP safety margin).

The schedule 6 in. Fig 206 schedule 80 piping is allowed in the above applications because 6 in. 602 does not exist.

The use of Figure 206 schedule 40 is limited to piping of various sizes used on burner booms. It is allowed for use on the booms due to weight constraints.

Any deviation from the guidelines listed herein requires an exemption as per the Management of Change and Exemption Standard (SLB-QHSE-S010).

### B.2.3.11 Procurement of Pipework Crossovers, Replacement Piping, and Flexible Hoses

In order to connect to Client owned, Rig, or other 3rd party equipment, procurement of crossovers from any of the pipework connections listed in Section Appendix B.2.1: Standardized Pipework Tables (the pipework tables) to any other API, ASME, or industry standard connection is allowed without an exemption unless the crossover is to a connection type which has specifically been banned.

In addition to the pipework listed in Section Appendix B.2.1: Standardized Pipework Tables, replacement of fig 206 piping sections on flarebooms is also allowed. Purchase of any other rigid piping which does not meet the specifications listed in the piping tables is banned.

Medium and high pressure flexible hoses must be procured with swaged end connections which match either one of those in the pipework tables, or one of the recognized fittings types given in Section 4.4.12: Fittings.

---

**Note**
The swage must be direct to the pipework connection or recognized fitting connection, it must not go via an intermediate thread.

---

Low pressure flexible hoses may be procured with any API, ASME or industry standard connection.

## B.2.4 General Technical Information Related to Pipework

### B.2.4.1 Identification of Testing Pipework

In addition to the specific markings stamped on each component of the pipework (heat treatment number, serial numbers, etc.), two official easy-to-read identified means are provided:

1. A stainless steel identification ring wrapped around the pipe and stamped with the following:
   - Manufacturer identification code, Schlumberger code or part number
   - Serial number or manufacturer's item number
   - Nominal diameter
   - Working pressure (WP) and test pressure (TP)

- Service type
- Date of manufacture or first pressure test
- Last test date and type (e.g., 1-31-06 WP)

**2.** A color band, related to the working pressure. The color code schemes are shown in Table B-2: Working Pressure Color Bands.

**Table B-2: Working Pressure Color Bands**

| Working Pressure | Pressure Band Color |
|---|---|
| 1500 | Light Blue |
| 2500[1] | Yellow |
| 5000 | Red |
| 10,000 | Black |
| 15,000 | White |
| 20,000 | Brown |

[1] 4 in. 602 SCH 80 is rated 2300 psi but uses yellow band.

## B.2.4.2 Hammer Union Lip-Seal versus Flange or Hub Metal-to-Metal Seal

The properties of the well effluent can have an effect on the durability of the elastomer lip seal fitted to a Hammer Union connection. A number of different elastomer compounds are available and an elastomer seal which is suitable for the anticipated job conditions must always be used. More details on seal selection are given the SWT FOH at InTouch Content ID 3916699.

In high-pressure applications, especially when flowing gas, the hammer union lip seal elastomer may experience explosive decompression. This is caused by gas migrating into the elastomer while it is under pressure and subsequent deformation and damage the lip-seal when the pressure is reduced. The lip-seal will then pop out of the grooves in the union and cause a leak.

The risk is greater at high temperature or when the gas contains a high $CO_2$ concentration. Therefore piping with a metal-to-metal seal shall be used for jobs with a high well effluent temperature or high $CO_2$ concentrations.

## B.2.4.3 Hammer Unions

A Hammer Union is composed of the following:

- A male Sub fitted with an internally threaded wing nut and depending on Fig type an O'ring seal on the male Sub.

- An externally threaded female Sub and depending on Fig type an elastomer lip seal.

## B.2.4.4 Direction of Flow through a Hammer Union Pipework

By convention, the flow enters the pipework on the female sub side and circulates from the female sub to the male sub.

All testing services equipment is manufactured to adhere to this convention and it should be followed whenever possible. However, there is no technical requirement for this convention and under certain circumstances, such as in a complex rig up or due to crossover availability, it may be required to rig up a line where the direction of flow is reversed. Any such line where the direction of flow is reversed must be clearly marked as to the true direction of flow.

## B.2.4.5 Identification of Hammer Unions by Manufacturers

The manufacturers (FCE/FMC, ANSON) identify the hammer unions by a figure number.

For sour service, a "SG" marking may be added (ANSON).

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**Note**

The Cold Working Pressure (CWP) shown on the Hammer Union Nut, does NOT identify the Testing Services assigned Working Pressure (WP) rating of the pipework to which the unions are attached. Always refer to the pipework identification bands and certification documentation.

---

## B.2.4.6 Hammer Union Mismatches Risks

By standardizing on certain sizes and types of hammer union connections, Testing Services have minimized the risk of having a mismatch between unions, however the issue becomes a much higher risk when interfacing with client or third party equipment.

Mismatching of hammer unions presents a severe mechanical hazard which compromises the pressure rating of the complete system. It presents a weak point which can fail under pressure resulting in death, severe injury and/or asset damage.

Such Mismatches occur in 5 main categories:

1. Mismatching the same size.

2. Mismatching the pressure ratings.
3. Mismatching of wing nuts.
4. Mismatching of components.
5. Mismatching of non-detachable and detachable components.

**THESE COMBINATIONS ARE VERY DANGEROUS**. Further details of these possible mismatches are as follows:

### Mismatching the Same-Size Hammer Unions

These mismatches refer to connecting hammer unions having the same size, but different figure numbers. The Wing Half of the 2 in. Fig 1502 can accept a female 2 in Fig 402, 2 in. Fig 602 or 2 in. Fig 1002. These mismatched connections can appear to make-up and will hold some pressure, but will fail due to lack of thread engagement.

The 2 in. 602 and 2 in. 1002 unions have been BANNED from TS operations for several years. There should be no 2” 602 or 2” 1002 unions in TS locations, but continued vigilance is required.

It is also possible that unions of these types will be encountered when interfacing to client or third party installations or equipment. Go No-Go gauges must always be used to confirm the connection type in these circumstances. Go No-Go gauges for all 3 types of connection (602 / 1002 / 1502) should be used to check the unknown thread as a means of cross-checking the connection.

The 2 in 402 union has never been approved for use on Testing Services Equipment or piping, however care should be taken if connecting to client or third party equipment.

The only 2" hammer union approved for use on Testing Services equipment, flowlines, or rigid piping is the 1502 style connection. The 2” 1502 union thread is 4.109” (104.4 mm) minimum OD.

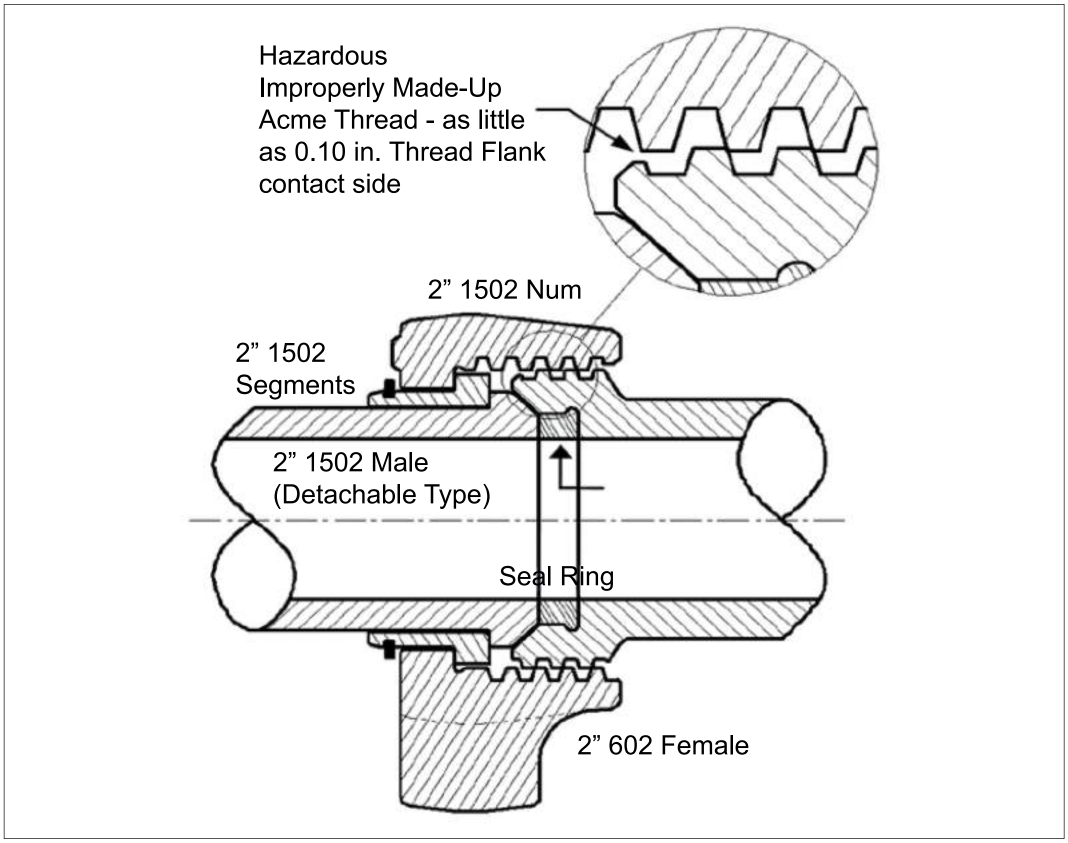


**Figure B-6: Mismatch of Hammer Union End Connections**

**Danger**

Potential Severity: Catastrophic
Potential Loss: Personnel
Hazard Category: Pressure

Never connect hammer union male and female threads that are not positively identified as having identical union figure numbers, size, and pressure rating. Mismatched connections may fail under pressure, which can result in serious personal injury, death and/or property damage.

**Note**

To enhance safety, all new 2” Figure 602 and 1002 female subs have been modified so they cannot engage the 2” Figure 1502 nut.

## Mismatching Pipe Pressure Ratings

This type of mismatch refers to connecting hammer union products having different pressure ratings but with end connections of the same size and figure number.

This occurs when mixing sour gas pipe with standard service pipe or when unions are welded to pipe with a working pressure lower than that corresponding to the union.

All TS piping is sour service and should not be mixed with WS standard service piping used in pumping operations.

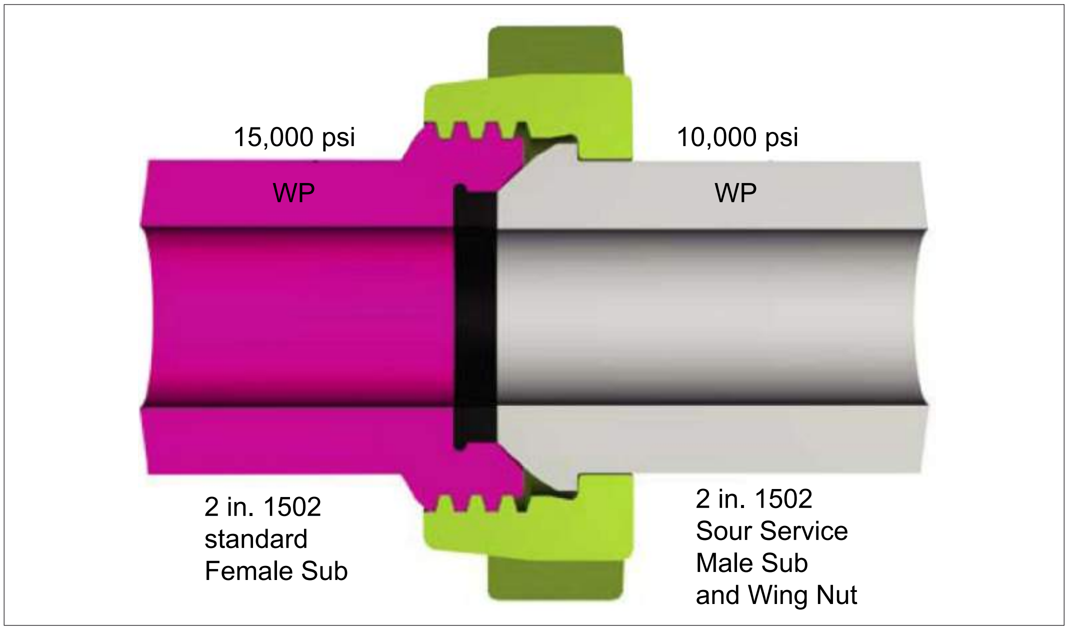


**Figure B-7: Mismatching of Sour and Standard Service Pressure Rating**

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**Danger**

Potential Severity: Catastrophic
Potential Loss: Personnel
Hazard Category: Pressure

Wing union components that cannot be positively identified with regard to manufacturer, size, figure number, pressure rating and **type of service** must never be used. Incorrectly identified components will lead to hazardous assemblies which can failed under pressure and result in serious personal injury, death and/or property damage.

---

## Mismatching Wing Nuts

This mismatch occurs when the wing nut of one size and figure number is mounted on the male sub of another size and figure number. There is only a small amount of engagement of the male sub in the wing nut and therefore the connection will not safely hold typical working pressures.

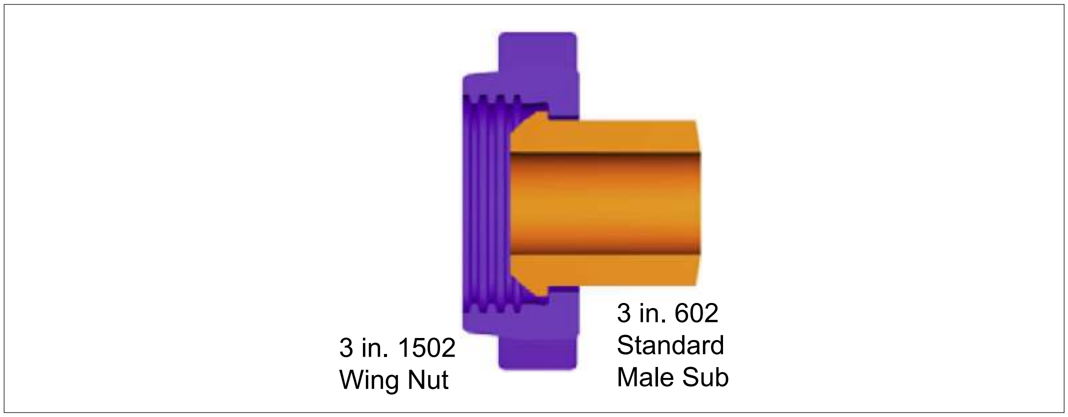


**Figure B-8: Mismatch caused by Misidentification - Standard Male Sub**

**Danger**
Potential Severity: Catastrophic
Potential Loss: Personnel
Hazard Category: Pressure

Never assemble any combination of male sub, wing nut or segments that are not positively identified to assure that union figure number, size, pressure rating and manufacturer are identical. Mismatched components will result in hazardous connections, which may failed under pressure, which can result in serious personal injury, death and/or property damage.

Similarly, a 2 in. Fig 1502 nut fits over a 2 in. Fig 602 or Fig 1002 male sub, but the nut shoulder has a minimal overlap with the shoulder of the male sub.

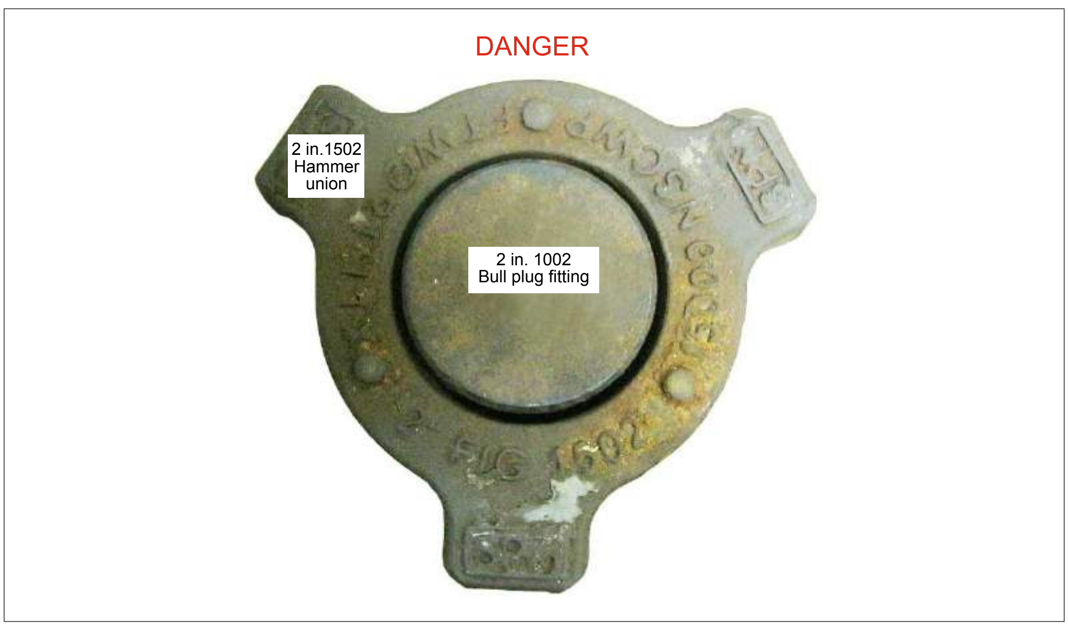


**Figure B-9: 2 in. 1502 Hammer Union and 2 in. Bull Plug Fitting**

## Mismatching Components

Mismatching of components occur when segments and nut of one figure number are made up to a detachable male sub with a different figure number. This results in a small amount of engagement of the male sub with the segment engaging the wing nut. This will not hold pressure safely during typical operations.

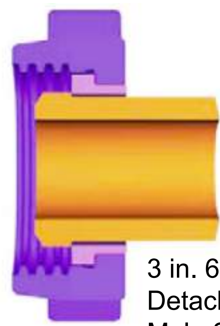


**Figure B-10: Mismatch caused by Misidentification - detachable Male Sub**

---

**Danger**
Potential Severity: Catastrophic
Potential Loss: Personnel
Hazard Category: Pressure

Never assemble any combination of male sub, wing nut or segments that are not positively identified to assure that union figure number, size, pressure rating and manufacturer are identical. Mismatched components will result in hazardous connections, which may failed under pressure, which can result in serious personal injury, death and/or property damage.

---

## Mismatching Non-Detachable and Detachable Components

This mismatch is caused by the assembly of non-detachable nuts on detachable male subs. The detachable wing nuts require a longer thread length to compensate for the segments between the wing nut and the sub shoulder. Use of a non-detachable wing nut in a detachable union results in a lack of thread engagement and an insufficient engagement between of the male sub shoulder with the wing nut ID.

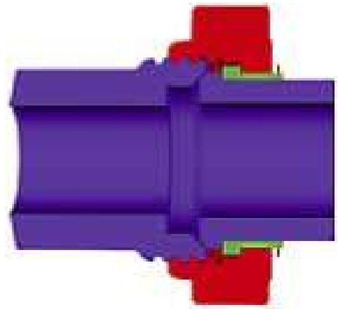

**Figure B-11: Misapplication of Wing Nuts**

4 in. 1002 non-detachable nut inappropriately used in a detachable union assembly. Notice the resulting lack of thread engagement with the female sub.

---

**Danger**

Potential Severity: Catastrophic
Potential Loss: Personnel
Hazard Category: Pressure

The misapplication of standard, non-detachable style wings nuts on 2 in., 3 in. and 4 in. Figure 602 and 1002 detachable nut connections will result in an unsafe connection leading to separation when under pressure.
Failure to avoid this condition may result in death, serious personal injury and severe property damage.

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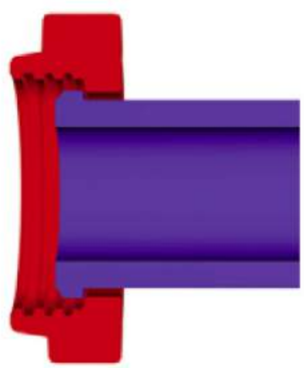

**Figure B-12: Another Misapplication of Wing Nuts**

4 in. 1002 non-detachable nut inappropriately assemble to a detached male sub end. Notice the excessive play between the ID of the nut and male sub OD behind the shoulder.

**Danger**
Potential Severity: Catastrophic
Potential Loss: Personnel
Hazard Category: Pressure

The misapplication of standard, non-detachable style wings nuts on 2 in., 3 in. and 4 in. Figure 602 and 1002 detachable nut connections will result in an unsafe connection leading to separation when under pressure.
Failure to avoid this condition may result in death, serious personal injury and severe property damage.

### B.2.4.7 Grayloc Connectors

Schlumberger Testing Services strongly recommends the use of Grayloc metal-metal seal connectors for high-pressure applications (15 kpsi).

**Note**
If 6" pipe is required upstream of the separator, the 6" Grayloc with a GR52 connection must be used. (See Figure B-3: Schlumberger Rating for “Grayloc” Clamp Connector Pipework).

**Table B-3: Average Torque Values for Two-pieces, Four-bolt Grayloc® Clamps***

| Stud Bolt Size | Stud Bolt Length (Inches) | Clamp Size | Average Torque | |
|---|---|---|---|---|
| | | | ft-lbs | Nm |
| ½-13UNC-2 | 3½ | 1 | 17 | 23 |
| ⅝-11UNC-2 | 5 | 1½ | 35 | 48 |
| ¾-10UNC-2 | 5¼, 6 | 2, 2½, 3 | 55 | 75 |
| ⅞-9UNC-2 | 7, 6¾ | 4, C, B | 90 | 122 |
| 1-8UNC-2 | 8½ | 5, D, E | 140 | 190 |
| 1⅛-8N-2 | 9⅜ | 6, F | 205 | 279 |
| 1¼-8N-2 | 10½ | 8 | 290 | 394 |
| 1⅛-8N-2 | 11¾ | XF | 330 | 449 |
| 1⅜-8N-2 | 11 | X8, G | 390 | 530 |
| 1⅝-8N-2 | 14¼, 14⅛, 17 | H, 10H, X14 | 630 | 857 |
| 1¾-8N-2 | 16, 19½ | X10H, 12M, X16 | 870 | 1,183 |
| 1⅞-8N-2 | 21½ | X18 | 1,170 | 1,591 |
| 2-8N-2 | 16½, 18½, 24¾ | P, X12M, X20 | 1300 | 1,768 |
| 2¼-8N-2 | 27, 20¾, 24 | X24, 30, 3V | 1,870 | 2,543 |
| 2½-8N-2 | 22, 31, 29½, 20 | S, U, 32, 36, 3W, 5P | 2,570 | 3,495 |

| Stud Bolt Size | Stud Bolt Length (Inches) | Clamp Size | Average Torque | |
|---|---|---|---|---|
| | | | ft-lbs | Nm |
| 2¾-8N-2 | 28¾ | Y | 3,500 | 4,760 |
| 3¼-8N-2 | 35½ | 40 | 7,100 | 9,656 |

*When using lubricated bolts. Double all torque values if bolts are not lubricated.

## Inspection of Grayloc Connectors

Make sure the connector hubs and clamp are clean before you begin the inspection.

- Check the seal ring for standoff. The seal ring rib should not be able to firmly contact the hub face. If it does, the seal ring must be replaced.

**Note**
The seal ring does not seat until the connector clamp is fully tightened.

- Visually inspect the hubs' seats for uniformity and freedom from burrs and deep scratches.
- Check the internal groove surface of the clamp halves or uniformity and freedom from burrs.
- Check the bolts and nuts for thread damage and any stretching/elongation of the bolts due to over-torquing.

**Note**

Mating Hub Connector Components from different manufacturers.

Mating hub components from different manufacturers typically occurs when interfacing with client or third party equipment.

The patent for © Grayloc has expired and © Grayloc will not endorse the integrity of the connection with components “copies” from another manufacturer. The mating of hub connector components from two different manufacturers (only) is allowed if:

- The components are dimensionally the same and mechanically equivalent.
- The hub connector face shall be from one manufacturer and ALL the other connector components shall be supplied by the other manufacturer. (See Figure B-13: Mating Hub Connector Components from Different Manufacturers).

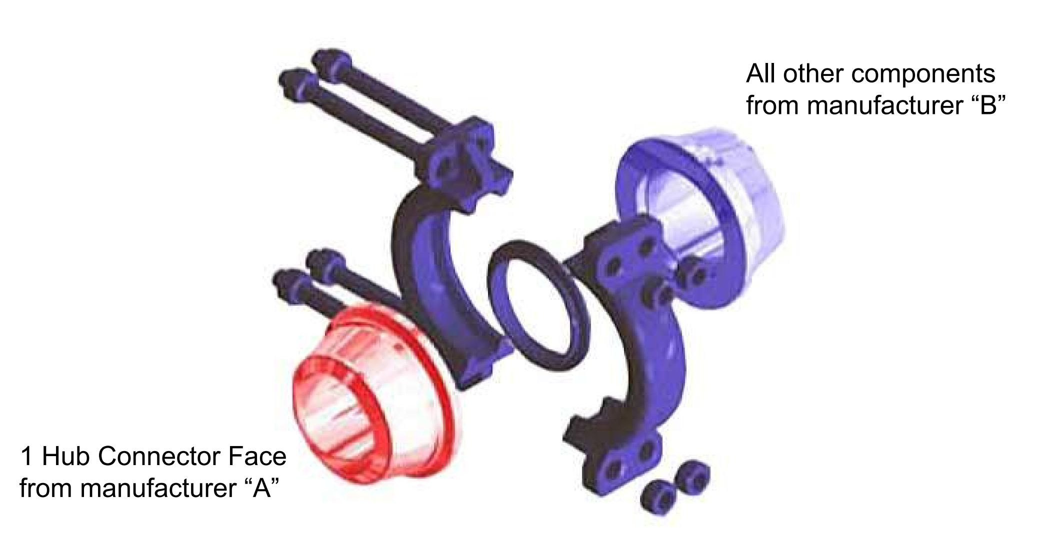


**Figure B-13: Mating Hub Connector Components from Different Manufacturers**

## Assembly and Disassembly of © Grayloc Connectors

To assemble, first make sure that the sealing faces of both hubs are clean. Place a seal ring in position between the hubs and move the pipes into a position where the clamp pieces can be put over the lips of the hubs. Insert the studs and screw nuts onto both ends. Do the nuts up hand tight, ensuring that the clamps remain evenly positioned on the hubs and are parallel with each other. Begin to tighten the nuts in a diagonal pattern to make sure that the clamps remain in the parallel position. This will ensure the application of an even force on the hub lips. Finally, and still following the diagonal sequence, a calibrated torque wrench must be used to tighten the nuts to the correct torque.

---

**Note**

It is mandatory that torque wrenches are calibration checked every year, and recommended that they are checked more frequently if in regular use. The calibration check status may be tracked in RITE by creating the wrenches under the file code TORQUE_WRENCH.

Some locations will have a specialist facility nearby which can calibration check the torque wrenches on a digital torque tester, however where this is not available, torque wrenches may be calibration checked by securing the socket drive in a vice and applying a known weight to the handle when it is in a horizontal position. The weight can be moved back and forth along the handle until the “give” point of the torque wrench setting is found. The force applied can then be calculated by measuring the distance between the centre point of the drive and the point at which the weight was acting on the handle. The calculation of weight times distance then gives the torque at which the wrench “gave” and this can be compared to the setting on the wrench. A number of such checks across the range of the wrench (or range of use) will then give the calibration factor for it, which should then be painted or stamped on a tag fixed to the handle so that it can be referred to each time the wrench is used and the setting adjusted accordingly. Any wrench which has a calibration factor outside the range 0.95 – 1.05 must be set to a specialist facility for repair or junked.

---

To disassemble, first verify that all pressure has been removed from the line before disassembling a Grayloc connector. Open a valve from the line or equipment to atmosphere if possible. The nuts should NOT be completely removed from the studs during the initial disassembly of the clamp. Loosen all 4 studs evenly, and ensure both clamp segments are slack to allow the safe release of any trapped pressure before finally removing the nuts from the studs. If the clamp segments remain stuck in place around the hubs, then both clamp segments must be loosened by jarring (i.e. a sound blow to the inside of the clamp ear with a soft hammer). The bolting can then be safely removed after release of any trapped pressure.

### *B.2.4.8* API 16B and 16BX Clamp Connectors (hubs) using API Specification 6A Seal Rings

These connectors are defined by standard API Specification 16A (Drill Through Equipment). They use seal rings type B or BX identical to the seal rings used for the API Specification 6A flanges.

Hubs do not have the angular restriction of flanges.

### *B.2.4.9* API Specification 6A Flanges and Spools

The standard sizes of API Specification 6A flanges, seal rings, dimensions and ratings are tabulated in Figure B-15: API Specification 6A Flanges and Ring Joints.

API flanges are widely used in the oil industry and can simplify the connection to client equipment, or the interconnections between Testing Services SWT equipment in confined spaces or HPHT applications. Flanged spools can be manufactured in any length to suit particular applications, or a crossover from an API flange to a different connection may be used.

---

**Note**

Reminder - All pressure-containing and pressure-controlling equipment including crossovers and surface piping shall be purchased exclusively through Schlumberger Product Centres.

---

The API Specification 6A flanges are easy to identify by pressure rating and ring-gasket API number. Due to the very limited wear during assembly, Schlumberger Testing Services does not down-rate the pressure rating of API flanges and hence uses the rating as stated by API Specification 6A. The drawback of API flanges is the restriction in angular position.

Due to this restriction, COFLEXIP hoses with API flanges should always be fitted with a X-Over/Saver Sub to Hammer Union or Grayloc connectors.

API-6A flanges shall be made up by applying the recommended torque values given in API Specification 6A Appendix D to the bolts.

The recommended torque values for the bolt sizes used with the API flanges most commonly encountered in Testing Services operations is given in Table B-4: Recommended Torques for Flange bolting.

**Table B-4: Recommended Torques for Flange bolting**

| Bolt Size | Studs with Yield Strength = 105 ksi bolt stress = 52.5 ksi (50%)Friction = 0.13 |
|---|---|
| | ft.lbf |
| 1/2 - 13 UNC | 59 |
| 5/8 - 11 UNC | 115 |
| 3/4 - 10 UNC | 200 |
| 7/8 - 9 UNC | 319 |
| 1 - 8 UN | 474 |
| 1 1/8 - 8 UN | 686 |
| 1 1/4 - 8 UN | 953 |
| 1 3/8 - 8 UN | 1281 |
| 1 1/2 - 8 UN | 1677 |
| 1 5/8 - 8 UN | 2146 |
| 1 3/4 - 8 UN | 2696 |
| 1 7/8 - 8 UN | 3332 |
| 2 - 8 UN | 4061 |
| 2 1/4 - 8 UN | 5822 |
| 2 1/2 - 8 UN | 8030 |

Table based on API 6A data.
Torque figures assume standard API 6A equipment well made up with a friction factor of 0.13 for a typical anti sieze compound.

In addition to applying the recommended torque values, the correct sequence in which to tighten the flange bolts must be followed so as to apply the force to the seal evenly. It will be necessary to follow the sequence several times before the flange connection becomes properly tight.

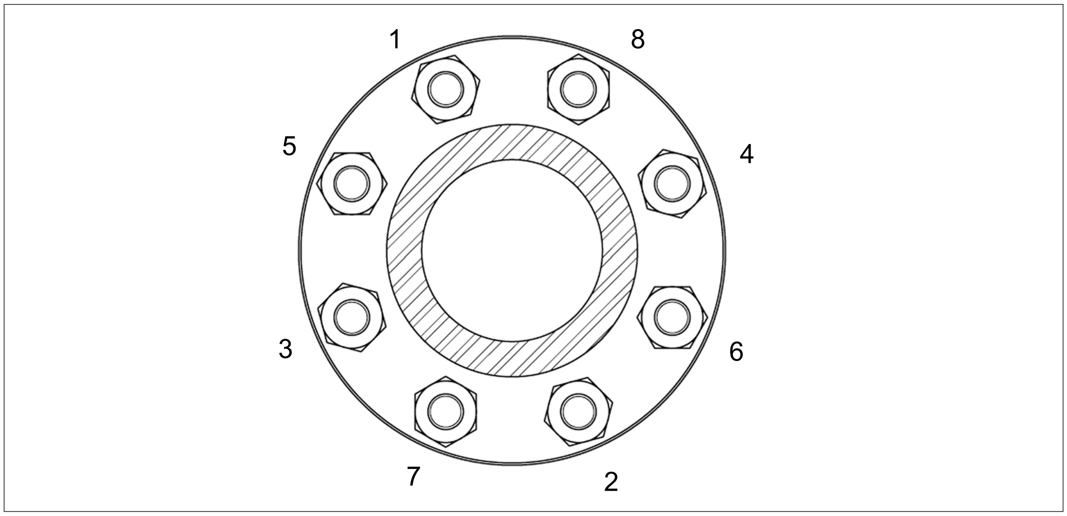


**Figure B-14: Flange Bolt Tightening Sequence**

A calibrated torque wrench must be used to ensure the correct torque values are applied.

The importance of correct make up of flange connections cannot be overstated. Wrong bolt sizing, bolt material, applied torque or tightening tecnique can easily make the connection weak. Overtorqued bolts may have been stretched past their elastic limit and may fail in service when exposed to pressure plus physical loading or thermal effects.

**Note**

It is strictly forbidden to apply torque to any connection while under pressure.

**Note**

It is mandatory that torque wrenches are calibration checked every year, and recommended that they are checked more frequently if in regular use. The calibration check status may be tracked in RITE by creating the wrenches under the file code TORQUE_WRENCH.

Some locations will have a specialist facility nearby which can calibration check the torque wrenches on a digital torque tester, however where this is not available, torque wrenches may be calibration checked by securing the socket drive in a vice and applying a known weight to the handle when it is in a horizontal position. The weight can be moved back and forth along the handle until the “give” point of the torque wrench setting is found. The force applied can then be calculated by measuring the distance between the centre point of the drive and the point at which the weight was acting on the handle. The calculation of weight times distance then gives the torque at which the wrench “gave” and this can be compared to the setting on the wrench. A number of such checks across the range of the wrench (or range of use) will then give the calibration factor for it, which should then be painted or stamped on a tag fixed to the handle so that it can be referred to each time the wrench is used and the setting adjusted accordingly. Any wrench which has a calibration factor outside the range 0.95 – 1.05 must be set to a specialist facility for repair or junked.

## Table B-5: Table of API Specification 6A Flanges and Ring Joints

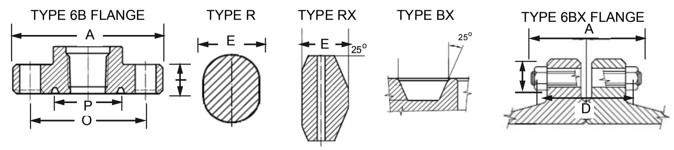


Figure B-15: API Specification 6A Flanges and Ring Joints

| FLANGE | | | | | FNG GASKET | | | BOLT STUDS | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| API Pressure Rating | Nom Size* | "Old" Nom Size | A outside Dia* | T* | P or G* O.D. | E Width* | API Nb. | 0 Bolt Circle* | No. | Size* | Length* | Casing Thread O.D.* |
| 2000 lb. WOG ("R" or "RX" Gasket) | 2-1/16 | 2 | 6-1/2 | 1-6/16 | 3-1/4 | 15/32 | 23 | 6 | 8 | 5/8 | 4-1/2 | 7 |
| | 2-9/16 | 2-1/2 | 7-1/2 | 1-7/16 | 4 | 15/32 | 26 | 57.8 | 8 | 3/4 | 5 | 8-5/8 |
| | 3-1/6 | 3 | 8-1/4 | 1-9/16 | 478 | 15/32 | 31 | 65.8 | 8 | 3/4 | 5-1/4 | 10-3/4 |
| | 4-1/16 | 4 | 10-3/4 | 1-13/16 | 578 | 15/32 | 37 | 8-1/2 | 8 | 7/8 | 6 | 13-3/8 |
| | 7-1/16 | 6 | 14 | 2-3/16 | 8-5/16 | 15/32 | 45 | 11-1/2 | 12 | 1 | 7 | 16 |
| | 9 | 8 | 16-1/2 | 2-1/2 | 10-5/8 | 15/32 | 49 | 13-3/4 | 12 | 1-1/8 | 8 | 20 |
| | 11 | 10 | 20 | 2-13/16 | 12-3/4 | 15/32 | 53 | 17 | 16 | 1-1/4 | 8-3/4 | |
| | 13-5/8 | 12 | 22 | 2-15/16 | 15 | 15/32 | 57 | 19-1/4 | 20 | 1-1/4 | 9 | |
| | 16-3/4 | 16 | 27 | 3-5/16 | 18-1/2 | 15/32 | 65 | 23-3/4 | 20 | 1-1/2 | 10-1/4 | |
| | 21-1/4 | 20 | 32 | 378 | 23 | 17/32 | 73 | 28-1/2 | 24 | 1-5/8 | 11-3/4 | |

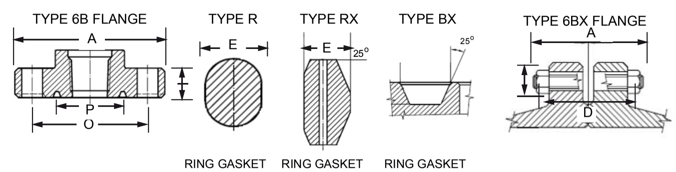


**Figure B-15: API Specification 6A Flanges and Ring Joints**

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3000 lb. | 2-1/16 | 2 | 8-1/2 | 1-13/6 | 3-3/4 | 15/32 | 24 | 6-1/2 | 8 | 7/8 | 6 | 7 |
| WOG | 2-9/16 | 2-1/2 | 9-5/8 | 1-15/16 | 4-1/4 | 15/32 | 27 | 7-1/2 | 8 | 1 | 6-1/2 | 8-7/8 |
| (“R” or “RX” | 3-1/8 | 3 | 9-1/2 | 1-13/16 | 4-7/8 | 15/32 | 31 | 7-1/2 | 8 | 7/8 | 6 | 10-3/4 |
| Gasket) | 4-1/16 | 4 | 11-1/2 | 2-1/16 | 5-7/8 | 15/32 | 37 | 9-1/4 | 8 | 1-1/8 | 7 | 13-3/8 |
| | 7-1/16 | 6 | 15 | 2-1/2 | 8-5/16 | 15/32 | 45 | 12-1/2 | 12 | 1-1/8 | 8 | 16 |
| | 9 | 8 | 18-1/2 | 2-13/16 | 10-5/8 | 15/32 | 49 | 15-1/2 | 12 | 1-3/8 | 9 | 20 |
| | 11 | 10 | 21-1/2 | 3-1/16 | 12-3/4 | 15/32 | 53 | 18-1/2 | 16 | 1-3/8 | 9-1/2 | |
| | 13-5/8 | 12 | 24 | 3-7/16 | 15 | 15/32 | 57 | 21 | 20 | 1-3/8 | 10-1/4 | |
| | 16-3/4 | 16 | 27-3/4 | 3-15/16 | 18-1/2 | 21/32 | 66 | 24-1/4 | 20 | 1-5/8 | 11-3/4 | |
| | 20-1/4 | 20 | 33-3/4 | 4-3/4 | 23 | 25/32 | 74 | 29-1/2 | 20 | 2 | 14-3/4 | |
| 5000 lb. | 2-1/15 | 2 | 8-1/2 | 1-13/16 | 3-3/4 | 15/32 | 24 | 6-1/2 | 8 | 7/8 | 6 | 7 |
| WOG | 2-9/15 | 2-1/2 | 9-5/8 | 1-15-16 | 4-1/4 | 15/32 | 27 | 7-1/2 | 8 | 1 | 1-1/2 | 8-5/8 |
| (“R” or “RX” | 3-1/6 | 3 | 10-1/2 | 2-3/16 | 5-3/8 | 15/32 | 35 | 8 | 8 | 1-1/8 | 7-1/4 | 10-3/4 |
| Gasket) | 4-1/16 | 4 | 12-1/4 | 2-7/16 | 6-3/8 | 15/32 | 39 | 9-1/2 | 8 | 1-1/4 | 8 | |
| | 7-1/16 | 6 | 15-1/2 | 3-5/8 | 8-5/16 | 17/32 | 46 | 12-1/2 | 12 | 1-3/8 | 10-3/4 | |
| | 9 | 8 | 19 | 4-1/6 | 10-5/8 | 21/32 | 50 | 15-1/2 | 12 | 1-5/8 | 12 | |
| | 11 | 10 | 23 | 4-11/16 | 12-3/4 | 21/32 | 54 | 19 | 12 | 1-7/8 | 13-3/4 | |
| API-BX | 13-5/8 | | 28-1/2 | 4-7/16 | 16063 | 0.786 | BX-160 | 23-1/4 | 16 | 1-5/8 | 12-1/2 | 13-3/6 |
| 5000 lb. | 16-3/4 | | 30-3/8 | 5-1/8 | 18832 | 0.705 | BX-162 | 26-5/8 | 16 | 1-7/8 | 14-1/2 | 16 |
| WOG | 18-3/4 | | 35-5/8 | 6-17/02 | 22185 | 1.006 | BX-163 | 31-5/8 | 20 | 2 | 17-1/2 | 18-5/8 |
| (“BX)” | 21-1/4 | | 39 | 7-1/6 | 24904 | 1.071 | BX-165 | 34-7/8 | 24 | 2 | 18-3/4 | 20 |
| (Gasket) | | | | | | | | | | | | |

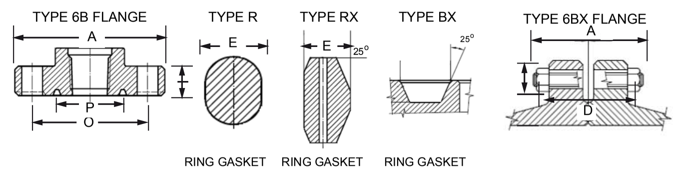


**Figure B-15: API Specification 6A Flanges and Ring Joints**

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| API-BX | 1-13/16 | | 7-3/8 | 1-21/02 | 3 002 | 0.406 | BX-151 | 5-3/4 | 8 | 3/4 | 5 | 7 |
| 10000 lb. | 2-1/16 | | 7-7/8 | 1-47/64 | 3 395 | 0.408 | BX-152 | 6-1/4 | 8 | 3/4 | 6-1/4 | 8-5/8 |
| WOG | 2-9/16 | | 9-1/8 | 2-1/64 | 4 046 | 0.554 | BX-153 | 7-1/4 | 8 | 7/8 | 6 | 9-5/8 |
| (“BX)” | 3-1/16 | | 10-5/8 | 2-19/64 | 4 685 | 0.606 | BX-.154 | 8-1/2 | 8 | 1 | 6-3/4 | 11-3/4 |
| (Gasket) | 4-1/16 | | 12-7/16 | 246/64 | 5 930 | 0.698 | BX-155 | 10-3/16 | 8 | 1-1/8 | 8 | 16 |
| | 5-1/16 | | 14-1/16 | 3-1/8 | 6 955 | 0.666 | BX-169 | 11-3/16 | 12 | 1-1/8 | 8-3/4 | 18-5/8 |
| | 7-1/16 | | 18-7/8 | 4-1/16 | 9 521 | 0.921 | BX-158 | 15-7/8 | 12 | 1-1/2 | 11-1/4 | 20 |
| | 9 | | 21-3/4 | 4-7/8 | 11 774 | 1.039 | BX-157 | 18-3/4 | 16 | 1-1/2 | 13 | |
| | 11 | | 25-3/4 | 5-9/16 | 14 064 | 1.149 | BX-158 | 22-1/4 | 16 | 1-3/4 | 15 | |
| | 13-5/8 | | 30-1/4 | 6-5/8 | 17 033 | 1.279 | BX-159 | 26-1/2 | 20 | 1-7/8 | 17-1/4 | |
| | 16-3/4 | | 34-5/15 | 6-5/8 | 18 832 | 0.705 | BX-162 | 30-9/16 | 24 | 1-7/8 | 17-1/2 | |
| | 18-3/4 | | 40-15/16 | 8-26/02 | 22 752 | 1290 | BX-164 | 38-7/16 | 24 | 2-1/4 | 22-1/2 | |
| | 21-1/4 | | 45 | 9-1/2 | 25 507 | 1373 | BX-164 | 40-1/4 | 24 | 2-1/2 | 24-1/2 | |
| API-BX | 1-13/16 | | 8-3/16 | 1-25/02 | 3 062 | 0.466 | BX-151 | 6-5/16 | 8 | 7/8 | 5-1/2 | 7 |
| 15000 lb. | 2-1/16 | | 8-3/4 | 2 | 3 395 | 0.498 | BX-152 | 6-7/8 | 8 | 7/8 | 6 | 8-5/8 |
| WOG | 2-9/16 | | 10 | 2-1/4 | 4 046 | 0.554 | BX-153 | 7-7/8 | 8 | 1 | 6-3/4 | 9-5/8 |
| (“BX)” | 3-1/16 | | 11-5/16 | 2-17/02 | 4 685 | 0.606 | BX-154 | 9-1/16 | 8 | 1-1/8 | 7-1/2 | 10 |
| (Gasket) | 4-1/16 | | 14-5–16 | 3-3/02 | 5 930 | 0.698 | BX-155 | 11-7/16 | 8 | 1-13/8 | 9-1/4 | 10 |
| | 7-1/16 | | 19-7/8 | 4-11/16 | 9 251 | 0.921 | BX-156 | 16-7/8 | 16 | 1-1/2 | 12-3/4 | |
| | 9 | | 25-1/2 | 5-3/4 | 11 774 | 1.039 | BX-157 | 21-3/4 | 16 | 1-7/8 | 15-3/4 | |
| | 11 | | 32 | 7-3/8 | 14 064 | 1.149 | BX–158 | 28 | 20 | 2 | 19-1/4 | |

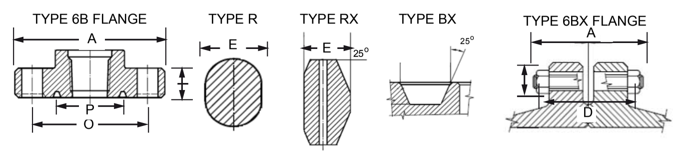


**Figure B-15: API Specification 6A Flanges and Ring Joints**

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| API-BX | 1-13/16 | | 10-1/8 | 2-12 | 3.062 | 0.466 | BX-151 | 8 | 8 | 1 | 7-1/2 | 7 |
| 20000 lb. | 2-1/16 | | 11-5/16 | 2-13/16 | 3.395 | 0.498 | BX-152 | 9-1/16 | 8 | 1-1/8 | 8-1/4 | |
| WOG | 2-9/16 | | 12-13/16 | 3-1/8 | 4.046 | 0.554 | BX-153 | 10-5/16 | 8 | 1-1/4 | 9-1/4 | |
| ("BX)" | 3-1/16 | | 14-1/15 | 3-3/6 | 4.685 | 0.606 | BX-154 | 11-5/16 | 8 | 1-3/8 | 10 | |
| (Gasket) | 4-1/16 | | 17-9/15 | 4-3/16 | 5.930 | 0.698 | BX-155 | 14-1/6 | 8 | 1-3/4 | 12-1/4 | |
| | 7-1/16 | | 25-13/16 | 6-1/2 | 9.521 | 0.921 | BX-156 | 21-13/16 | 18 | 2 | 17-1/2 | |

* Dimensions en inches

### B.2.4.10 ASME / ANSI flanges

Flanges made to the specification ASME B16.5 (formerly ANSI B16.5) are found on many items of Testing Services equipment, including diverter manifolds and separators.

The pressure rating of these flanges will decrease as the operating temperature increases.

When performing high temperature jobs it is important to be aware of the WP ratings at the specific well fluid temperature.

A range of values for the Group 1.1 Materials typically used in construction is in Table B-6: Maximum Allowable non-shock Working Pressure of ASME Flanges* (psig).

**Table B-6: Maximum Allowable non-shock Working Pressure of ASME Flanges* (psig)**

| Operating Tempe-rature | Pressure Class (lb) | | | | | | |
|---|---|---|---|---|---|---|---|
| **(degC)** | **150 #** | **300 #** | **400 #** | **600 #** | **900 #** | **1500 #** | **2500 #** |
| **-29 to 38** | 284 | 741 | 988 | 1481 | 2222 | 3703 | 6171 |
| **50** | 278 | 727 | 969 | 1453 | 2181 | 3635 | 6058 |
| 100 | 257 | 676 | 901 | 1352 | 2028 | 3379 | 5632 |
| **150** | 229 | 654 | 872 | 1308 | 1961 | 3269 | 5448 |
| 200 | 200 | 635 | 847 | 1271 | 1906 | 3176 | 5294 |

* Only valid for carbon steel flanges and not for alloy flanges as rating may vary.

## B.3 Pipework Maintenance and Certification

### B.3.1 FIT

Prior to load out all items of Pipework and Crossovers must undergo a FIT check which is a verification that it is ready for use.

It must be clear of internal obstructions (sand / soil, scale, rags, etc.), free of obvious physical damage, and female Hammer Unions must be fitted with seals.

The TRIM and Q-Check status must be verified and up to date in RITE and the Annual Survey color coded band must be in place and valid in accordance to Section Appendix B.3.3.1: Identification of Pipework Annual Survey Status.

Paintwork, including the WP colour band, must be in good condition.

## B.3.2 TRIM

A TRIM shall be conducted after each job and consist of a visual inspection as described under "Visual Inspection of Pipework" below.

Where the piping has been subjected to adverse conditions such as high velocities (i.e. High flow rate jobs), solids production (See POM section 4.6.5: Solids Production) or corrosive fluids, random wall thickness checks (especially on elbows) and a pressure test to working pressure are also required, unless a detailed record of thickness checks performed during the job on each piece of pipe used in the rig up is available and can be attached to the RITE Work Order for the TRIM.

If the on job thickness checks are available and attached to the Work Order then only a random sample of 10% of the pipe needs to be thickness checked as confirmation of the on job readings. If discrepancies between the on job and post job thickness measurements are found, then all the pipe must undergo thickness checks during the TRIM.

In either cases, if thickness checks are required on all the pipe during the TRIM, it must also undergo a pressure test to Working Pressure.

For Testing Express production tests where there are frequent short duration jobs a time element will apply instead and a TRIM will be performed at a maximum interval of three months unless the piping has been subject to corrosive or erosive environments in which case a TRIM shall be performed immediately after rig down.

In all cases the pipework TRIM must be updated in RITE with details of any thickness measurements entered into, or attached to, the work order so that a proper history for each pipe can be documented.

Piping shall follow the Mandatory Piping Colour coding For Annual Survey set out in Section Appendix B.3.3.1: Identification of Pipework Annual Survey Status.

### B.3.2.1 Visual Inspection of Pipework

The purpose of the visual inspection is to identify non-conforming, sub-standard, or obviously damaged items which should be immediately junked, without the need for any further detailed inspection.

The Visual inspection consists of:

- Verify that the Quality file for the item is available.
- Ensure that the Pipe, Data Header, Tee, or Crossover was manufactured by an approved supplier.
- Ensure that nothing has been welded to the exterior surface of the pipe or crossover (such as a support or bracket).
- Verify that each piece has a band with a serial number; if the band is missing, perform the necessary research to identify the component's serial number. If it is not possible to identify the original serial number the item must be junked.
- Check the internal bore of the piece for erosion, corrosion, or build up of scale or other deposits. A torch may help with this process. If scale or other deposits are present, they should be removed by flushing, by scraping with a bar, or by using a rotating wire brush. If the piece shows any signs of erosion or corrosion, test the point of concern with the ultrasonic thickness tester.

  For Tees closely inspect the intersection of the bores for cracks.
- In the case of Pipe or crossovers fitted with hammer unions perform the checks as detailed in section .
- In the case of pipe or crossovers fitted with Grayloc connections perform the checks as detailed in Appendix B.3.6: Grayloc Hub and Connector Check.
- In the case of pipe or crossovers fitted with flange connections, check the sealing faces for damage.

## B.3.3 Annual Survey

All pipework shall undergo an annual survey within Q1 of each year that consists of a visual inspection, checks of wall thickness, hammer unions integrity check or Grayloc hub and clamp inspection, and a pressure test to test pressure.

Wall thickness checks on all piping straights, elbows, crossovers and Tees should be performed as follows:

**a)** At a distance of between 4 and 6 inches (100 - 150 mm) away from each end connection, measure 4 points which are at 90 degrees to each other.

**b)** Unless either items "d." or "e." below apply, at the mid point of each item (and at the mid point of each leg on Tees) measure 4 points which are at 90 degrees to each other.

**c)** For items exceding 6 ft (2 m) in length, one additional random point should be measured between the mid point and each end.

**d)** For short, straight, items, (such as most crossovers) where the mid point measurement would be within 1 ft (25 cm) of either end, the mid point measurement may be omitted.

**e)** For elbows, the mid point measure point which is on the inside of the elbow radius may be omitted, but the other 3 points of it (top and bottom, and on the outside of the radius) must be performed.

**f)** Tees (and Y's) should be considered as two elbows which are back to back, where the mid point of the outside radius forms one common measurement point.

**g)** Welded pipework assemblies (such as the fixed piping on Separators or Surge Tanks) should be viewed and measured as if they had been assembled from individual straights, Tees and Y's".

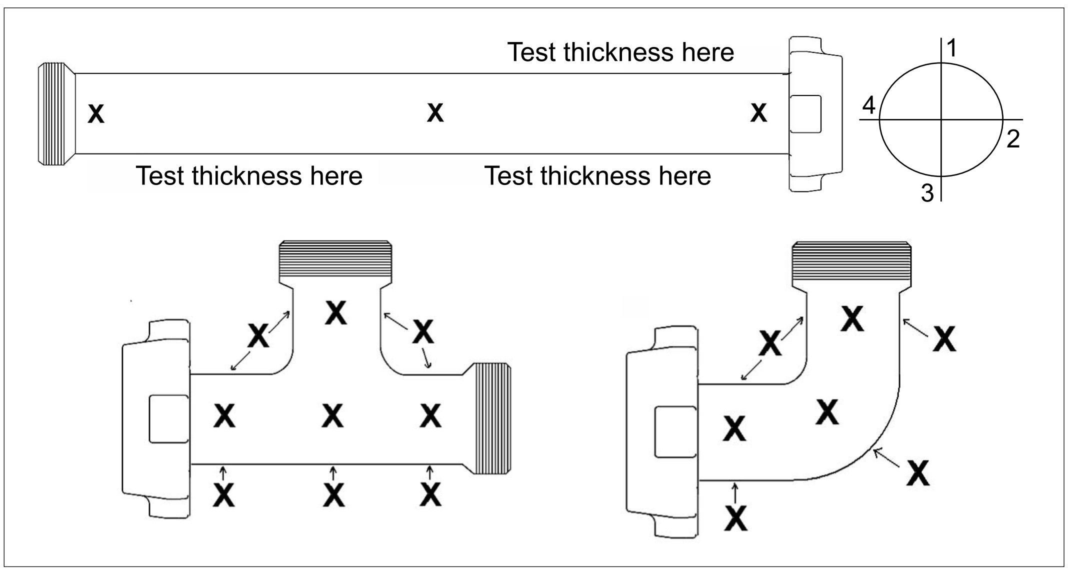


**Figure B-16: Thickness Tests**

The survey results shall be added into the equipment quality file and RITE shall be updated. Additionally the Pipework shall be colour coded as described below and inspection/certification dates stamped on the metallic identification band as per Figure B-17: Schlumberger Piping Identification.

**Note**

If the measured wall thickness is within 10% of the minimum wall thickness, evaluate the operating conditions of the pipe and inform management of an impending need of replacement.

**Note**

Having a certifying authority witness the annual survey is not required by this standard but may be required to meet local regulations or customer requirements.

**Note**

Pressure testing to Test Pressure may flex the pipe and loosen any scale or deposits still inside. It is recommended to remove the test caps, and then flush through the entire length of pipework assembled for the test at the highest flow rate possible to remove any loose solids.

### B.3.3.1 Identification of Pipework Annual Survey Status

RITE is the primary maintenance recording system where formal certification and inspection records are captured. However, due to the large number of items involved an Annual Survey colour coding procedure has also been implemented specifically for pipework in order to provide a quick and easy method of visual identification of survey status.

All pipework (piping, elbows, data headers, crossovers, adapters, flanges, etc.) must be certified within Q1 of each year. For new piping received during the year, the colour coding applicable is the same as if it had been certified in Q1 of that year.

This means that Q1 is the only period where it is acceptable to have two colour codes in service - pipework which underwent a survey the previous year, and piping which has undergone a survey in the current year.

The maximum allowable period between surveys on any given piece of pipe or crossover remains 12 months – items which were surveyed in January one year should be surveyed in January the following year. The 3 month overlap period is given in recognition of the fact that it is not normally possible for a location to put all its pipework and crossovers through a survey at the same time and that a rotation of “Due for Survey” and “Recently completed survey” items will need to take place.

Some items of pipe or crossovers may need to be put through a survey before the 12 month time limit in order to facilitate this rotation process. (For example pipework which was surveyed in March one year may have to be done in January the next year so that it is available to replace other piping which is due for survey in February or March).

It is the date of the pressure test which is considered to be the date of the survey. It is acceptable to put pipework through the inspection process in December of one year ready for final pressure test and colour coding in January the next year, as long as the pipe is not used between inspection and pressure test. This is allowed so that jobs loading out in January can be equipped with pipework which will remain in survey for a full 1 year period.

Piping and crossovers going on a job must have a current Annual Survey with an expiry date which is at least as far in the future as the estimated job duration plus one month at the time of load out.

Though similar in process, the Annual Survey is an internal Schlumberger requirement, while the 5 years Major Survey is an industry standard. To fully comply with this industry standard, locations must ensure that the 5 years Major Survey is valid for the entire period for which the pipe is colour coded, i.e. That it does not expire before the pipe or crossover is due for its next Annual Survey. If this is not the case, the 5 years major re-certification must be performed before applying the relevant color code.

It is forbidden to use any pipe or crossovers which are not identified with the current colour code band. Pipework which does not have a current survey status colour band must be removed from operations and put in a quarantine area until it can be verified as having a current survey and re-banded, or put through the survey process.

The colour code band must not be painted and must be easily removable at the end of the year. 50 mm wide water resistant tape (avoid making multiple wraps with a narrower tape) or heavy duty cable ties of at least 10 mm width are recommended. The colour band should be applied close to the female (Thread) end of the pipe.

The colour codes have been chosen so that they cannot be confused with the colours used to identify the WP rating of pipework, and are repeated over a 3 year schedule. The schedule is as follows:

- 2010 = Grey
- 2011 = Orange
- 2012 = Green
- 2013 = Grey

- 2014 = Orange
- 2015 = Green
- etc.

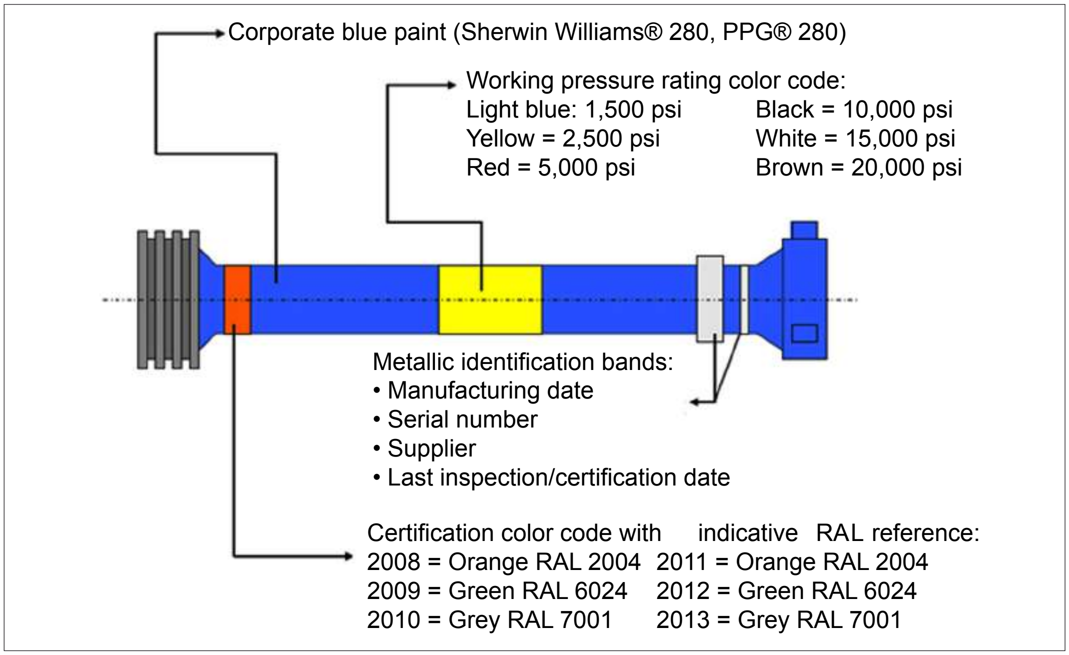


**Figure B-17: Schlumberger Piping Identification**

## B.3.4 Pipework Major Re-Certification

Every 5 years at least, pipework must be re-certified. It is equivalent to an Annual Survey but it must be witnessed by a certifying authority.

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**Note**

Pressure testing to Test Pressure may flex the pipe and loosen any scale or deposits still inside. It is recommended to remove the test caps, and then flush through the entire length of pipework assembled for the test at the highest flow rate possible to remove any loose solids.

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## B.3.5 Hammer Union Integrity Check

A Visual Inspection should be performed on all hammer unions as follows:

Points to Check for a TRIM:

- Wing nut thread condition - obvious wear, cracking or pitting of the thread (If any doubt exists the threads should be given MPI and dimensional checks).

- Female thread condition - obvious wear, cracking or pitting of the thread half (If any doubt exists the threads should be given MPI and dimensional checks).
- Obvious wear on the backside face of the male hub where the wing nut shoulders.
- Obvious wear of the segments (collet pieces) fitted to integral male unions.
- Condition of the retainer ring (circlip) which retains the segment (collet) pieces in integral unions. (The circlip should not be bent and when the union is assembled should hold the segments (collets) firmly in place.

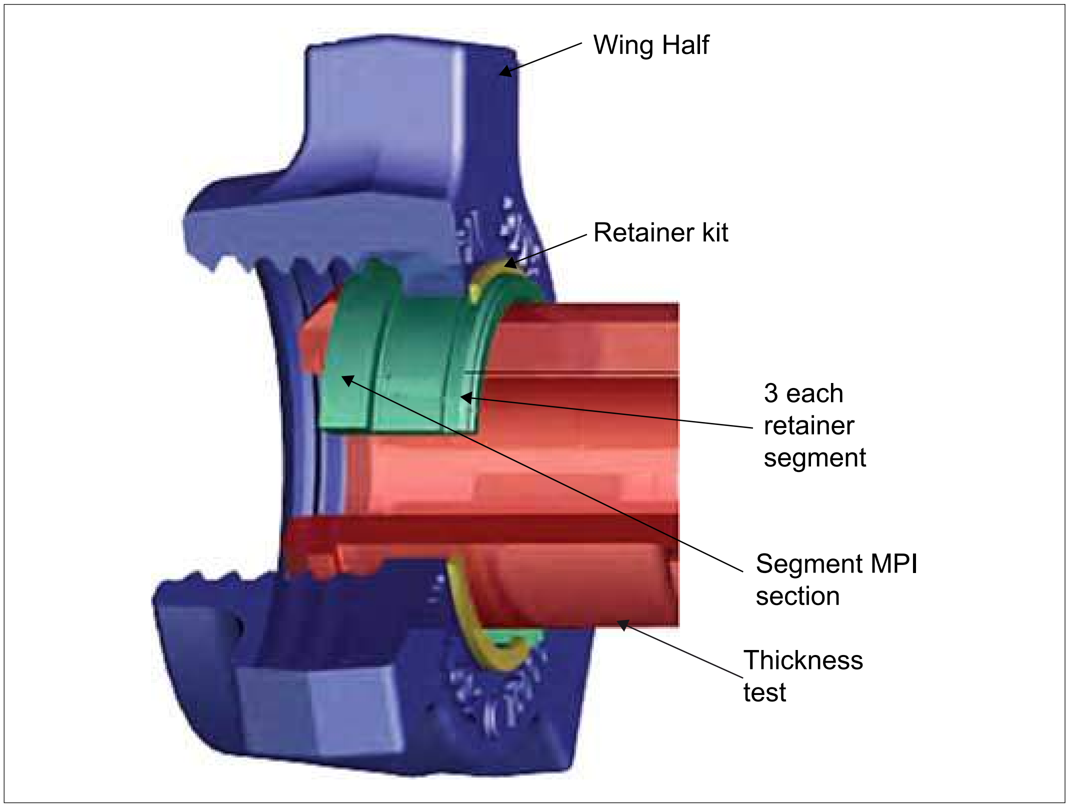


**Figure B-18: Hammer Union Diagram**

For an Annual or Major Survey, perform the TRIM checks plus:

- MPI of the segments (collet pieces) fitted to integral male unions.
- Heavily beaten wing nuts should be dressed by grinding following the instructions below.
- The wing nut lug height should be measured and compared against the table below.

### Height and Width check for Wing Nut Lugs

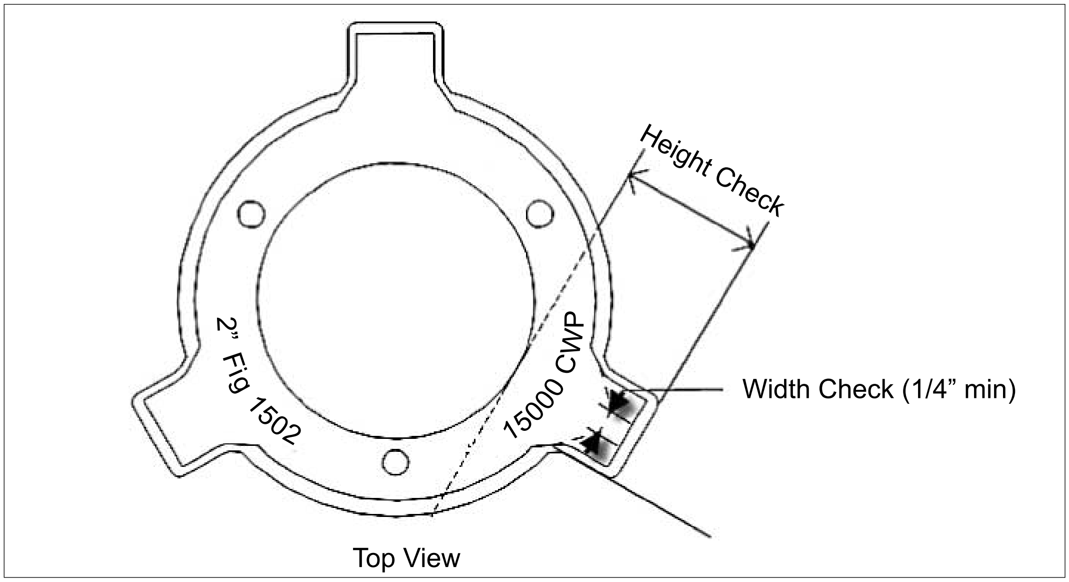


**Figure B-19: Height and Width check for Wing Nut Lugs**

Hammer Union wing nut lugs must meet the following dimensional criteria.

**Table B-7: Hammer Union Wing Nut Lugs Dimensional Criteria**

| Hammer Union Nut | Original Height (Inches) | Minimum Height (Inches) |
|---|---|---|
| 6" Fig 206 | 2.18 | 1.88 |
| | | |
| 3" Fig 602 | 2.34 (2.18) | 2.00 (1.84) |
| 4" Fig 602 | 2.35 (2.28) | 2.00 (1.93) |
| | | |
| 3" Fig 1002 | 2.34 (2.18) | 2.00 (1.84) |
| 4" Fig 1002 | 2.35 (2.28) | 2.00 (1.93) |
| 6" Fig 1002 | 2.93 | 2.56 |
| | | |
| 2" Fig 1502 | 2.06 | 1.79 |
| 3" Fig 1502 | 2.25 | 1.97 |
| 4" Fig 1502 | 3.00 | 2.65 |

Figures in brackets are for the Integral Union nuts which have a larger ID, the 1502 nuts are dimensionally the same for both Integral and Welded hammer unions as the detail of the male end changes rather than the nut.

## Grinding Guide for misshapen Wing Nut Lugs

Grind down any damage on the lugs on the wings to the configuration shown below. Remove any wings that have one or more lugs that are damaged to the point shown in C below:

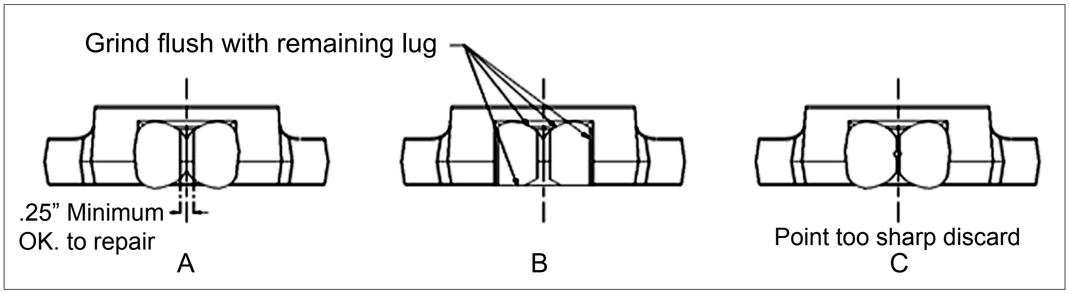


**Figure B-20: Grinding Guide for misshapen Wing Nut Lugs**

### Confirmation Check

Thread Go/No Go gauges can be used to positively identify hammer unions whenever doubts exist with a union Fig. type. It is strongly recommended to use the gauges to check and confirm connections when interfacing with Client or Rig hammer unions.

The gauges can be purchased from SRPC via External sales.

EXTB 1069 3” 602 Male Plug Gauge
EXTB 1070 3” 602 Female Ring Gauge

EXTB 1071 4” 602 Male Plug Gauge
EXTB 1072 4” 602 Female Ring Gauge

EXTB 3577 3” 1002 Male Plug Gauge
EXTB 3578 3” 1002 Female Ring Gauge

EXTB 3579 4” 1002 Male Plug Gauge
EXTB 3580 4” 1002 Female Ring Gauge

EXTB 3581 6” 1002 Male Plug Gauge
EXTB 3582 6” 1002 Female Ring Gauge

EXTB 3583 2” 1502 Male Plug Gauge
EXTB 3584 2” 1502 Female Ring Gauge

EXTB 1067 3” 1502 Male Plug Gauge
EXTB 1068 3” 1502 Female Ring Gauge

EXTB 3585 4” 1502 Male Plug Gauge
EXTB 3586 4” 1502 Female Ring Gauge

EXTB 3587 6” 206 Male Plug Gauge
EXTB 3588 6” 206 Female Ring Gauge

**Figure B-21: Ring Gauge and Plug Gauge**

## B.3.6 Grayloc Hub and Connector Check

Visual Inspection for TRIM, Annual or Major survey as follows:

- Remove scale rust or any foreign matter from the hub faces by using a cloth or nylon brush.
- Visually inspect the hub's seats for uniformity and freedom from burrs and deep scratches (Minor burrs and scratches can be removed from the Hub face/ring seat by a fine steel wool, for deep pitting or scratching consult InTouchSupport.com for advice on re-facing).
- Check the external surfaces of the clamp halves for damage or cracking (If any areas are suspect then perform an MPI of the area of concern).
- Check the internal groove surface of the clamp halves for uniformity and freedom from burrs.
- Check the bolts and nuts for thread damage and any stretching/elongation of the bolts due to over-torquing.

# *B.4* Pipework Check Valve Maintenance and Certification

The following requirements are the minimum required for the maintenance of Pipework Check Valves. Some check valves may come with manufacturer's documentation which gives increased requirements, and if this is the case then increased requirements should be followed instead.

## *B.4.1* FIT

Prior to load out Pipework check valves must undergo a FIT check which is a verification that they are ready for use. They must be clear of internal obstructions (sand / soil, scale, rags, etc.), free of obvious physical damage, and female Hammer Unions must be fitted with seals.

The valve should also be checked for operation by ensuring that the flapper is free to move (This is best done by pushing the flapper into the open position by using a wooden stick).

The TRIM and Q-Check status must be verified and up to date in RITE, and Paintwork, including the WP colour band, must be in good condition.

## *B.4.2* TRIM

A TRIM shall be conducted after each job. Dis-assemble the valve, clean all parts and check the conditon of the seat and flapper. Replace as required. Perform a visual inspection on the rest of the valve as described in section for Pipework, including the Hammer union integrity check as described in section . Re-assemble the valve using new O-Rings / rubber parts as applicable and perform pressure tests to WP. (One Test for the body, one valve seat test). Finally dry out the valve internals and apply a light oil or corrosion inhibitor before fitting end caps.

## *B.4.3* Annual Survey

Pipework Check Valves shall undergo an annual survey every 12 months, which consists of a TRIM, plus the additional checks on the Hammer Unions for an annual survey as described in section . Thickness checks are not generally required as check valves are not usually used in positions where they are subject to errosion, however they should be visually inspected internally for signs of any erosion or corrosion and put aside for more detailed checks if any is noted.

**Note**

The pressure test requirement for a check valve undergoing an annual survey is a test to WP only, as described under Appendix B.4.2: TRIM. However locations may find it more convenient to test check valves along with pipework and body test them to TP instead. The seat test must only ever be to WP.

## B.4.4 Pipework Check Valve Major Re-Certification

Pipework check valves must be re-certified at a minimum frequency of 5 years intervals. It is the same as an annual survey, but with the body test done to Test Pressure. The re-certification must be witnessed by a certifying authority.

# B.5 Flexible Test Lines

Schlumberger Testing Services normally utilizes Flexible test lines in DST and PTL applications.

- In DST application, the hose provides a single length, two connections only, which is safe and easy to install. A DST Hose is designed to operate in a temporary set up with duration of less than 72 hr.
- In PTL applications (extended test) the hose is designed for production tests with no duration limit.

Schlumberger Testing has currently qualified 2 suppliers of Flexible test lines:

- Technip Drilling and Refining Application Division which supply Coflexip®, designed for sour service ($H_2S$).
- Parker who supply Black Eagle® hoses which are designed for standard service, but which do not comply to API 6A and can therefore only be used downstream of the Choke Manifold or for Kill line applications.

A flexible test line (COFLEXIP, Black Eagle or any future approved supplier) usually consists of connectors, terminations, lifting/handling collar and a flexible line. The connectors can be supplied with any end-fittings, the most practical being API hubs which can then be fitted with saver subs or crossovers. Direct connection between an API flanged flexible hose and an API flange on a fixed point is not recommended as, due to the angular restrictions of flanges, a torsional moment may be induced in the hose. Hammer union terminations should be avoided as hammer union saver subs have a greater risk of leakage, and damage to the union on the hose termination would require the hose to be re-swaged. The terminations interface between the fixed attachment points and the flexible pipe and have several functions such as, mechanical attachment to the flexible pipe, provide seal against inner effluent, provide seal against outer environment and mechanical attachment to the outer stainless steel carcass.

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**Note**

Where Flexible Hoses are equipped with Hammer Union end connections, the hammer unions must undergo an integrity check when the hose is given a TRIM, Annual or Major survey in accordance with Section . Care must also be taken in respect of Section , especially when replacing segment (collet) pieces or wing nuts.

---

## B.5.1 Coflexip® Hoses

Testing Services use Coflexip® Drill Stem Test (DST) and Production Test Lines (PTL) for Flowline applications. These are distinct from other hoses in the Coflexip® range (such as the hoses for BOP Choke and Kill lines) and must not be confused with them, as the maintenance and certification requirements are not the same.

For information on Coflexip handling, care, inspection, maintenance and certification. See the Coflexip Users Guide InTouch Content ID 3015903.

The correlation between RITE terminology and that used in the User's Guide in respect of maintenance and surveys is as follows:

- FIT = External Inspection.
- TRIM = External Inspection plus Internal inspection (plus a pressure test to WP).
- Q-Check = Full Inspection.
- CE (Major Survey) = Manufacturers Inspection (Major Survey).

The TRIM pressure test performed on reception of a new hose should be of 24 h duration. Subsequent TRIM pressure tests need only be until 15 minutes of stable pressure is achieved.

When performing a TRIM it is important to verify that the hose exposure on the most recent job performed has been correctly recorded in RITE. See Section Appendix B.5: Flexible Test Lines for further details.

The optional field pressure testing detailed in the users guide relates only to permanently installed choke and kill lines, not to hoses used for DST applications.

Where Major surveys cannot be conducted by the manufacturer or by a manufacturer approved third party then an exemption as per the Management of Change and Exemption Standard (SLB-QHSE-S010) is required, with approval at Area level.

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**Note**

In common with most other items of surface testing equipment, the maximum service life of a Coflexip® hose is 20 years. Hoses older than this must be junked.

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## B.5.2 Flowrates

The maximum continuous fluid velocity inside a Coflexip hose should be considered the same as any API or ASME specification pipework. The end connections are more likely to suffer abraison than the hose itself.

For any other smooth-bore (i.e., thermoplastic inner sheathed lines) the fluid velocity should not excede 49 ft/s [15 m/s] for any kind of fluids. The limit for a Black Eagle hose is 30 m/s for non abrasive fluids (i.e. mono-phase fluids).

---

**Note**

The potential damage depends on the abrasive properties of the flow medium and the above fluid velocity shall be reduced if solids are anticipated. Contact InTouchSupport.com on a case by case basis for assistance with Architest simulation if solids or high flowrates are expected.

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## B.5.3 Pressure and Temperature Rating

Flexible hoses shall be chosen in accordance to temperature, pressure and fluid type expected. Refer to manufacturer’s specifications. See also .

The stamped working pressure must be understood as the maximum design pressure to which the line can be exposed. Surge factor must be considered for the particular job.

Maximum working temperature vs. exposure time limits must be respected and any hose exposed to temperature above normal continuous rating shall be removed from service upon completion of work in progress.

## *B.5.4* Aging

Flexible hoses will age according to conditions of exposure. Accurate records of $CO_2$, $H_2S$, Acid, pressure and especially temperature exposure versus time must be maintained and recorded in RITE on a service report, and hoses retired from service according to manufacturer's specifications. These records must be reviewed prior to a major survey being carried out to ensure the re-certification is justified or if certain conditions have been reached where the hose shall be retired. Hoses missing records will not be accepted by the manufacturer for Major Survey re-certification.

## *B.5.5* Inspection of Flexible Flow lines

The very nature of a flexible pipe's construction and that of its end-fittings does not allow a detailed examination of the internal integrity. Therefore the operational verification must be based on external visual examination and regular pressure testing.

## *B.5.6* Certification Validation

Flexible lines shall be inspected and tested preferably by the manufacturer or by a manufacturer approved third party.

When the manufacturer or approved third party are not available for the inspection or the operation is highly impractical (exportation, transport, customs, lead time, etc…) the inspection can be performed by any other competent third party inspection body, as long as all the inspections and tests are as per manufacturer manual/ instructions.

Tests and inspections performed either by manufacturer or by third party must be witnessed and approved by a certifying authority.

The recommended periodicity of each certification inspection test varies depending on the application, refer to manufacturer's manual.

## *B.5.7* Routine Visual Inspection

### *B.5.7.1* External Inspection

An in-house external inspection of the flexible line shall include as a minimum:

- Check that both end fittings are properly attached to the hose body and that neither hose nor fittings show signs of any stress.
- Check the hose body along its' full length to ensure that it has no signs of wear or damage.
- Check the connections for damage to the seal.

### *B.5.7.2* Internal Inspection

A visual inspection of the inner surface of the end-fittings shall be done after cleaning, to check that it is free of cracks and that any corrosion resistant coating is undamaged.

In case of cracks or severe abrasion, the line should be removed from service and the manufacturer or manufacturer’s approved vendor should perform a more detailed inspection.

The lines can be checked for internal collapse by using an internal pigging or gauging method

### *B.5.7.3* Periodicity of Routine Visual Inspection

Routine inspection of flexible lines shall be performed before and after every job.

## *B.5.8* Annual Survey

The Annual Survey shall be conducted every year either by manufacturer or by manufacturer approved vendor.

The Annual Survey must include:

- A full external inspection.
- An internal inspection of the ends.

The inspection must show that the ends are free from any collapse of the internal lining. Either visual inspection or internal pigging or gauging or endoscope may verify this.

A pressure test to Original Equipment Manufacturer (OEM) test pressure (TP).

The inspection results must be filed with the Quality File.

## *B.5.9* Major Survey

Flexible Hoses shall undergo a Major Survey every 5 years. Major Surveys must be witnessed and approved by a certifying authority.

The Major Re-Certification must include:

- Entire external inspection.
- Entire internal inspection of the hose and of the ends, using an endoscope or similar.
- Full pressure test at OEM test pressure, as marked on the flexible line and for a 24 hr duration.

Additionally, some flexible hoses may be required to undergo bending at the minimum bending radius. Refer to the Manufacturers documentation for the hose concerned.

The inspection results must be filed with the Quality File.

## *B.5.10* Pressure Test Ratings

The pressure test ratings of flexible hoses must be verified in the original equipment manufacturer manuals or quality files, but must not, in any case, exceed the Schlumberger Testing Services assigned Test Pressure for the end connections.

All Schlumberger Testing pressure-testing rules must be adhered to.

The complex inspection and testing of flexible lines implies that the job history must be carefully recorded in the history card after each job.

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**Note**
Flexible lines without complete Quality Files must be retired immediately. A retired flexible line must be clearly stamped NOT-REUSABLE.

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# *B.6* Low Pressure Flexible Hoses

## *B.6.1* Definition

Low Pressure: Pressure equal to or below 285 psi (1967 kPa).

**Note**

This pressure is defined by the ambient temperature pressure rating of a class 150 flange Group 1.1 materials specified in ASME B 16.5 Annex F.

Low pressure flexible hoses falling into the above definition are generally found in surface well testing operations application in the following:

1. Pump suction
2. Air supply to burners
3. Water supply to burners
4. Steam supply
5. Steam return
6. Utility Water supply
7. Utility air supply

## B.6.2 Technical Specifications

Low pressure flexible hose shall be rated to have a WP of 285 psi or less and a safety factor between rated WP and burst pressure of at least 4 is recommended. The material of the hose construction must be in accordance to SAE or ISO/EN codes for the appropriate fluids, mineral oils/water or methanol/glycol. These specifications must be stated in a COC supplied with the hose.

The pressure rating must also be printed along the length of the hose body.

Low pressure hoses may have a maximum nominal diameter of 4 inches.

It is recommended that low pressure flexible hoses have swedged end connections.

There may also be specific local regulations or client requirements for end connections.

The use of threaded connections on Low pressure hose is permitted as specified in , and it is not allowed to use low pressure flexible hoses when $H_2S$ is present.

## *B.6.3* Maintenance and Inspection of Low Pressure flexible Hoses

All flexible hoses require traceability and maintenance. Each individual hose must carry a stainless steel (rust free) identification rings showing as a minimum the manufacturer's part number, a serial number, Working Pressure and Test Pressure. Inspection and tests shall be tracked via RITE.

Each length of hose must be regularly inspected (FIT), and any observed damage or deformation of the hose assembly must be a cause for repair/rejection/disposal. A TRIM is a FIT plus a pressure test to WP. A Q-Check is the same as a TRIM, but with a pressure test to 1.5 times WP. Local regulations may also dictate certain requirements. If coiled up, the coil diameter of the flexible hose must be larger than any minimum diameter of curvature specified by the manufacturers.

In cases where steam generators and air compressors are supplied by a third party, hoses supplied with the equipment must conform to the minimum standards listed above. An exception is allowed for steam hoses which may have a WP above 285 psi provided that they meet all the other criteria and they are never used for any other purpose.

## *B.6.4* Use of Low Pressure Flexible Hoses

When selecting low pressure flexible hoses, care must be taken to ensure that the construction material of the hose and end fittings is compatible with the type of fluid to be conveyed, as chemical reactions may occur and subsequently lead to a release (leak) of fluids or complete failure of the hose or connections with a resulting environmental impact or risk of physical injury to personnel.

Care must also be taken when rigging up to avoid points where the hose may be pinched between heavy or sharp objects, tensile loading (stretching), or excessive heat.

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**Danger**

Potential Severity: Major
Potential Loss: Personnel
Hazard Category: Pressure

Pressurized hoses with crowfoot connections must be secured with whipchecks and R-clips at every connection. Refer to the SWT FOH (InTouch Content ID 3916699) for more information.

---

# B.7 Medium and High Pressure Flexible Hoses and Liners

## B.7.1 Definition

Medium and High Pressure: Pressure above 285 psi.

**Note**
This pressure is defined by the ambient temperature pressure rating of a class 150 flange Group 1.1 materials specified in ASME B 16.5 Annex F.

Medium and High pressure flexible hoses and liners falling into the above definition are generally found in well testing operations in the following applications:

1. Control lines and umbilicals
2. Instrumentation liners
3. Chemical injection hoses
4. Sampling liners
5. Pressure test liners
6. Discharge lines

## B.7.2 Medium and High Pressure Flexible Hose Technical Specifications

Medium and High pressure flexible hoses with a WP of 12,500 psi or less must have a design safety factor between rated WP and burst pressure of at least 4. Hoses with a WP above 12,500 psi must have a safety factor of at least 3.5. The material of the hose construction must be in accordance to SAE codes for the fluids with which the hose will be used, and the working temperature range of the material must be appropriate for the application. These specifications must be stated in a COC supplied with the hose. The pressure rating must also be printed along the length of the hose body.

Medium and High pressure flexible hoses must have swedged end connections. Swedges must be direct to an end fitting appropriate to the pressure rating and application of the hose without going via an intermediate thread. No cast or brazed connections are allowed.

Hose end fittings should never be of a WP which is less than the WP of the hose, and in any case shall be marked either with their WP, or with other identification which allows their WP to be determined. (For example a part number).

Re-swedging of hoses shall only be carried out by the manufacturer, the manufacturer's agent, or trained personnel.

## *B.7.3* Maintenance and Inspection of Medium and High Pressure Flexible Hoses

All flexible hoses require traceability and maintenance. Each individual hose must either:

**a)** Carry a stainless steel (rust free) identification rings showing as a minimum the manufacturer's part number, a serial number (or other unique identification reference), the maximum and minimum temperatures at which the hose can be used, Working Pressure and Test Pressure.

or

**b)** Have sufficient information moulded into the outer sheath of the hose to enable individual identification and specifications to be determined.

Inspection and tests shall be tracked via RITE.

Each length of hose must be regularly inspected (FIT), and any observed damage or deformation of the hose assembly must be a cause for repair/rejection/disposal.

A TRIM is a FIT plus a pressure test to WP. Pressure tests should be conducted for a minimum duration of 1 hour to allow for the detection of slow leaks.

A Q-Check is the same as a TRIM, but with a pressure test of 1 hour duration to 1.5 times WP. Local regulations may also dictate certain requirements.

A Major survey is a Q-Check, plus a review of the documentation held for the hose and its job history. Hoses which have been exposed to fluids which are not compatible with their specification should be junked.

Hoses which are re-swaged at the wellsite may be pressure tested just to WP, but on return to the base must undergo a test to 1.5 x WP. Hoses re-swaged at the base or by an outside 3rd party contractor should be pressure tested to 1.5 x WP at the time of swaging.

If coiled up, the coil diameter of the flexible hose must be larger than any minimum diameter of curvature specified by the manufacturers.

## *B.7.4* Metallic Liners

Metallic liners are not recommended for applications where they are regularly rigged up and down. They are best suited to permanent installations.

When used they should be of Stainless 316, Inconel 625, Inconel 825 or Super Duplex 2507 seamless tubing, and used with end connections from recognized suppliers such as swagelock or Autoclave.

When used in permanent installations, they may be treated as an integral part of the main equipment and inspected and tested as part of the equipment's regular schedule. Metallic liners which are used in temporary situations must follow the rules set out in Section Appendix B.7.3: Maintenance and Inspection of Medium and High Pressure Flexible Hoses.

# *B.8* Appendix B Revision History

For more details see Appendix F.

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**Warning**

Potential Severity: Serious
Potential Loss: Security
Hazard Category: Human

The controlled source document of this manual is stored in the InTouch Content ID 3045666. Any paper version of this standard is uncontrolled and should be compared with the source document at time of use to ensure it is up to date.

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# Regional Manufacturing, and Local Remanufacturing and Repair of Pressure Containing or Controlling Equipment

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# C Regional Manufacturing, and Local Remanufacturing and Repair of Pressure Containing or Controlling Equipment

## C.1 Regional Manufacturing

The Regional Manufacturing Service provides a process to supply manufacturing support services to the field and allows the establishment of machining facilities that have been independently qualified to produce pressure containing components.

These manufacturing facilities are geographically selected in order that field locations can gain the most efficient supply chain advantage regarding delivery and minimal freight costs. At present this service applies mainly to the production of crossover components but it has been designed to support the regional manufacturing process where the field can request local manufacturing of components that fit into the capabilities listing of the regional manufacturer.

### C.1.1 Surface Testing

SRPC have approved various regional manufacturing/repair centres for Surface Testing pressure containing and controlling equipment. The process to utilize these facilities with or without a Regional Manufacturing Supervisor is laid out in Section Appendix C.8: SRPC - Testing Services Equipment Repair Process Chart.

### C.1.2 Below Flowhead / Downhole Crossovers

The process of selection and qualification of factories or machine shops on behalf of field locations for the manufacture of downhole crossovers is controlled by the regional manufacturing group (RMG) in Aberdeen which has been integrated into SRC and renamed RTST RR Crossover Group. This process has been formatted primarily around the manufacture of Subsea, DST and Completion ancillary crossovers component and the group will continue to support below flowhead crossovers as well as test caps, lifting subs and the manufacturing support service.

**Warning** Potential Severity: Serious
Potential Loss: Assets
Hazard Category: Human, Pressure

It is a Schlumberger MANDATORY action that all orders for below flowhead Crossovers shall be instigated only through the Rapid Response process via OneCAT.

It is a Schlumberger MANDATORY action that all orders for below flowhead Crossovers shall be instigated only through the Rapid Response process via OneCAT. The objective for this action is to achieve 100% traceability and POM compliance of all Schlumberger tubular crossovers and to avoid catastrophic failures as experienced in the past with uncontrolled manufactured components. To ensure this, crossover's will be manufactured with both a Quality Control Plan (QCP) and an Engineered Design which has been approved by a Schlumberger Technical or Product Centre, the process and procedures for ordering components via OneCat are as follows.

Phase 1 Quote, (within 7 days):

- Field submitter creates a cart in OneCat for an existing crossover or specifies a new product.
- Submit cart for quote.
- RTST-RR receive quote.
- RTST-RR obtain manufacturing quote from vendor.
- RTST-RR apply vendor and engineering charges to quote, send results to submitter.
- Pending quote answer from field.

Phase 2 Design (7 - 28 days depending on approval response and if existing product):

- When quote approved, RR will start the RFQ.
- Engineering PO released in SWPS.
- PO approved by field location.
- Engineering start design.
- Design complete and package ready for vendor.
- Invoice engineering fees to fields location.

Phase 3 Manufacture (depends on approval of PO and machine shop availability):

- Field location send PO for crossover manufacture to vendor**.
- Vendor request manufacturing package from RTST-RR.
- Crossovers manufactured and expedited to field location.

  **If the regional machine shop is not required a PO can be placed with RTST-RR who will manage the vendor selection, manufacturing and delivery process**

If RTST-RR cannot meet the delivery schedule following the above workflow the procedure set out in Section Appendix C.1.2.1: Regional Manufacturing Emergency Crossover Supply Process may be implemented.

## C.1.2.1 Regional Manufacturing Emergency Crossover Supply Process

Following is regional manufacturing's emergency supply process:

1. RFQ is raised for crossover component through the OneCAT system as normal, defining full component details and delivery schedule.
2. If Rapid Response cannot meet the requested delivery schedule for any reason they shall inform the submitter of the RFQ of this fact by email, and advise them that they should follow the steps 3 to 5 detailed below.
3. In order to gain approval for this deviation from the Testing Services RR Crossover Procedure, a QUEST entry shall be raised for an Exemption to the Manufacturing Process with Expert Approval requested from the RTST-RR Manager, Geomarket Approval requested from the Geomarket QOSM or Ops Manager, and final approval requested from the Area QOSM.

   This exemption shall state the type of crossover and all relevant mitigating circumstances regarding the short delivery date.

   **Note**
   Without permissions from this group then crossover manufacture outwith the catalogue shall not be permitted.

4. Following the granting of the exemption, the requestee shall locate the nearest approved vendor or regional manufacturer (from SWPS Listing) with capabilities for the design and manufacture of the component concerned and will complete the process in accordance with the dictates of this Appendix.
5. This component, if designed and validated by the selected local manufacturer, should be treated as a 'proprietary' product of that company and therefore the quality assurance factors of the product must be checked by the field location requesting the emergency supply. It will be the field location's responsibility

to check that the component is supplied fit for service in accordance with the requirements of the POM and the Minimum Quality Package defined by the POM.

### C.1.2.2 Maintenance of Downhole or Below Flowhead Crossover

In the absence of a Downhole or below flowhead crossover maintenance manual, maintenance of Downhole or Below flowhead crossover should be conducted as per the guidelines in InTouch Content ID 4146802.

### C.1.2.3 Crossover Redressing and Re-cuts

Redressing" of a thread is limited to smoothing of the existing thread surfaces without altering the profile or pitch of the original thread. Threads may be redressed (or chased) locally by an approved vendor without submitting an RFQ in OneCAT.

Where a thread has been damaged beyond the point where a thread redress is sufficient to restore the function of the connection and a re-cut is required, or if there is a requirement to re-cut a crossover with a different thread, the requirements should be submitted in an RFQ through OneCAT.

It should be noted that re-cuts may not always be possible; this will depend on the original design of the crossover.

Re-cutting a crossover with the same thread as it had before will mean a modification to the part number to indicate a recut has occured.

Re-cutting a crossover with a different thread will also mean that the part number of the crossover will change, due to both the change in length and the change of thread type.

Any change of part number must be updated in the RITE record, and revisions to the Q File will also be required.

### C.1.2.4 Sub and Tool Joint Redressing and Re-Cuts

Where the thread of a sub or top/bottom connection of a tool has been damaged beyond the point where a thread redress is sufficient to restore the function of the connection, then an In Touch ticket should be submitted to the product centre which is responsible for the manufacture of the tool concerned, giving the part number of the tool or Sub. Advice will then be given as to whether or not the thread can be re-cut and which process is to be followed.

# *C.2* Local Remanufacturing and Repair

**No local manufacturing, repair or procurement of pressure containing or controlling Equipment to be used in Schlumberger Testing Services Operations shall be allowed outside the responsibility of a Schlumberger Technology Center unless specifically authorized under this standard. This includes any frame or transportation skid into which the equipment is built.**

Local remanufacturing or repair of equipment authorized under this standard shall be carried out in workshops which have been qualified and approved for the purpose. Requests for such approval shall be documented and submitted by GeoMarkets for review and acceptance by the Technology Centers. Any approval given is granted for specific products, in accordance with the vendor capabilities.

A properly trained procurement/manufacturing supervisor, nominated by the Area or Geomarket management, shall supervise local remanufacturing or repair of equipment. Training and certification of this supervisor is provided through the courses provided for the maintenance organization in the Training centres.

Please refer to Appendix C.8: SRPC - Testing Services Equipment Repair Process Chart at the end of this appendix for guidance on equipment repair.

Any deviation from this standard must be managed via Management of Change and Exemption Standard (SLB-QHSE-S010).

# *C.3* Applicability

This standard applies to the remanufacturing or repair of pressure controlling or containing equipment carried out by a workshop outside the direct control of a Product/Technology Center.

# *C.4* Vendor Responsibilities

When undertaking manufacturing/remanufacturing or repairing to Schlumberger Product Centre specifications, the vendor's responsibility is limited to:

- Conformance with the engineering and manufacturing file
- Quality of material and workmanship
- Respect of commercial terms.

Responsibility for proper performance of the manufactured item rests with the owner of the design and engineering file.

When supplying non-Schlumberger designed items, the vendor is fully responsible for the performance of the product sold and for its compliance with the requested specifications, industry codes and government regulations.

# C.5 Responsibilities

## C.5.1 Testing Services Operations Support

It is Testing Services Operations Support Managers responsibility to:

- Set and maintain the standards.
- Maintain the list of excepted items.
- Evaluate exemption requests.

## C.5.2 Area

It is the Area's responsibility to:

- Appoint the local manufacturing/procurement supervisor(s).
- Ensure competence of the supervisor through appropriate training.
- Select and qualify vendors through Technology Center involvement and ensure proper confidentiality agreements are in place (the area legal counsel can supply model agreement).
- Maintain the list of workshops in their area which have been approved, and the purpose for which they were approved.

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**Note**

Depending on the Area, the Local Manufacturing/Procurement Supervisor could be a shared resource between several business Segments.

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## C.5.3 Manufacturing and Procurement Supervisor

It is the Manufacturing and Procurement Supervisor's responsibility to:

- Organize for vendor qualification.
- Perform the vendor follow up.
- Ensure local manufacturing/remanufacturing or repairing is done according to Testing Services requirements.

- Ensure that workshops are provided with the required documents and obtain all the required information from the appropriate technology center.
- Ensure product inspections and controls are in place and are performed before product delivery (including third party certification, quality file, as required).

### C.5.4 Technology/Product Centers

It is the Technology/Product Centers responsibility to:

- Train and certify the appointed local manufacturing/procurement supervisors.
- Provide technical assistance to the area, as required.
- Audit and qualification of vendors.
- Manufacturing files (drawings, specifications, QC plans, etc.)
- Acceptance and commissioning including Quality File documents review.

## C.6 Documentation

Any equipment which undergoes Remanufacturing or Repair under the provisions of this Appendix must conform with the requirements of POM sections 2.4.3: Replacement of Parts or Equipment Repair / Re-Manufacturing and 2.4.3.1: Repair / Re-Manufacturing Documentation.

## C.7 Exceptions

Locations which have a properly trained Manufacturing and Procurement Supervisor may manufacture / remanufacture, repair or procure the following items of equipment without the involvement of a Schlumberger Product or Technology centre:

- Low pressure flexible hoses as defined in POM section Appendix B.6: Low Pressure Flexible Hoses and conforming to the technical specifications given in POM section Appendix B.6.3: Maintenance and Inspection of Low Pressure flexible Hoses.
- Medium and high pressure flexible Hoses and Liners as defined in POM section Appendix B.6.1: Definition and conforming to the specifications given in POM section Appendix B.7: Medium and High Pressure Flexible Hoses and Liners. (This does NOT include hoses which will be used for the flow of Hydrocarbons - all hoses for this purpose must only be purchased through a Schlumberger Product centre).

- Air compressors (Max 150 psi) for shop or field use.
- Air Driven Transfer Pumps.
- OEM replacement hydraulic hoses for industrial equipment or winch units.

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**Note**

Locations with a Manufacturing and Procurement Supervisor may also purchase or repair equipment or items which do not contain or control pressure - such as containers, racks, and baskets etc. without involving a Schlumberger Product or Technology centre.

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# *C.8* SRPC - Testing Services Equipment Repair Process Chart

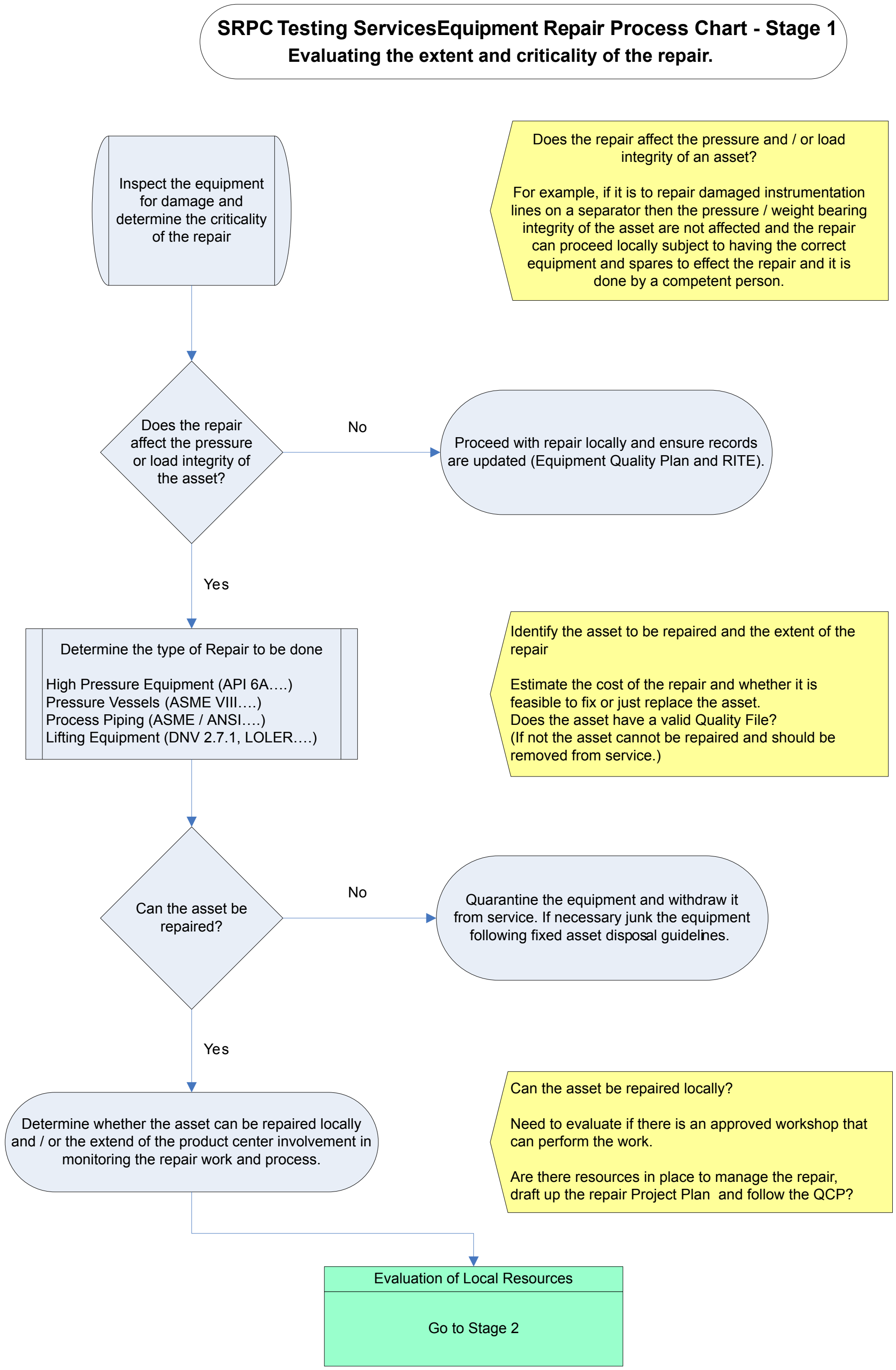


**Figure C-1: SRPC Testing Services Equipment Repair Process Chart - Stage (1)**

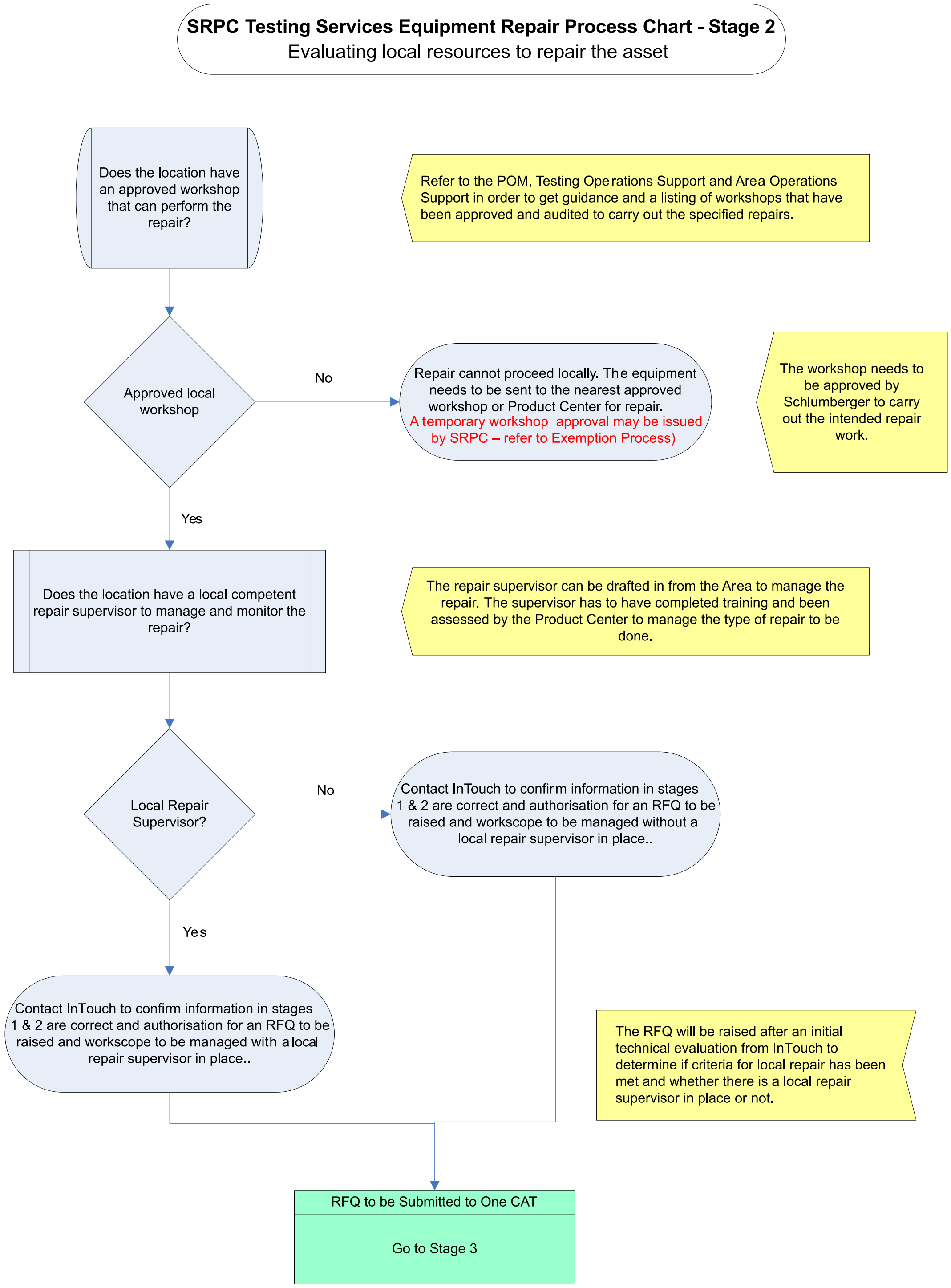


**Figure C-2: SRPC Testing Services Equipment Repair Process Chart - Stage (2)**

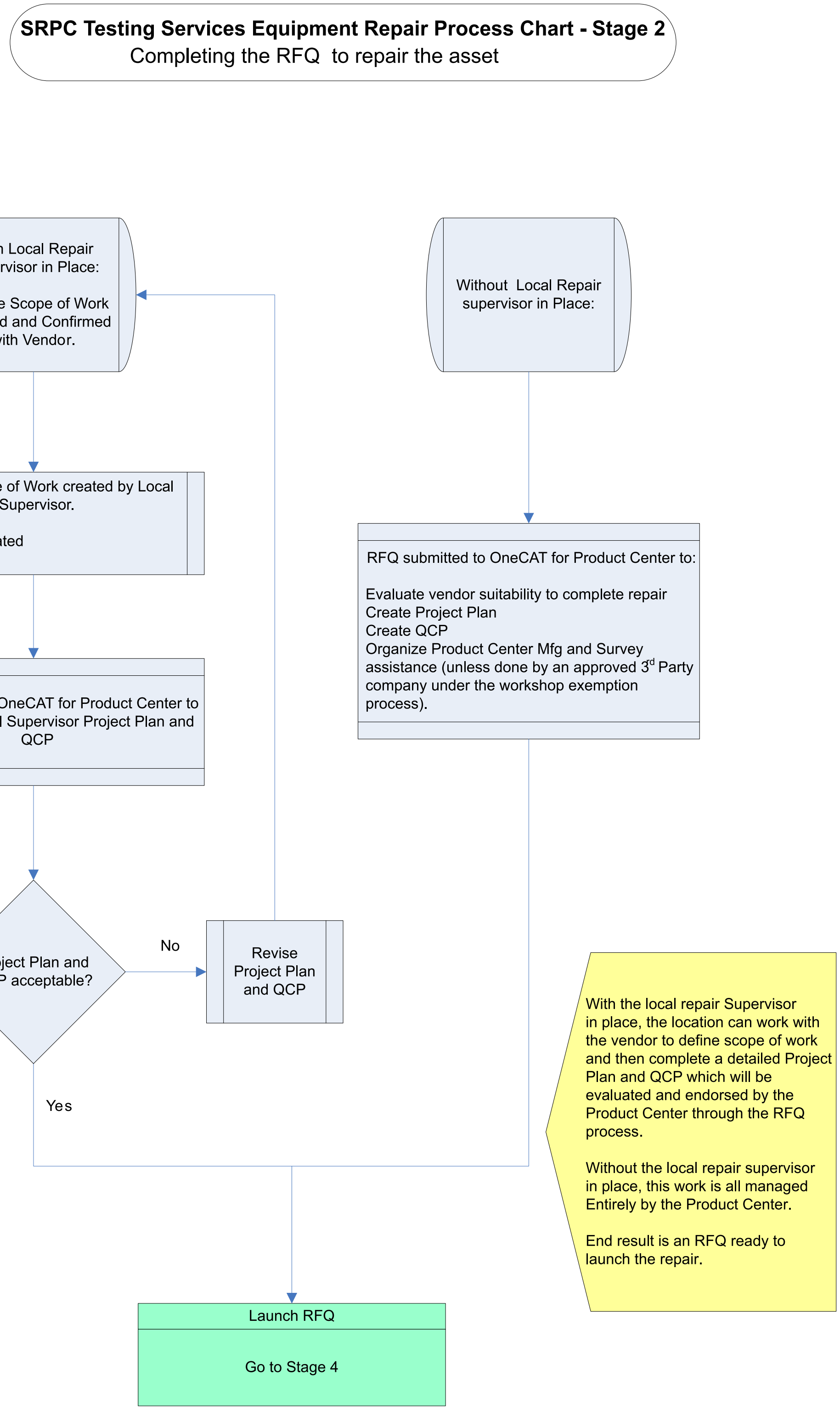


**Figure C-3: SRPC Testing Services Equipment Repair Process Chart - Stage (3)**

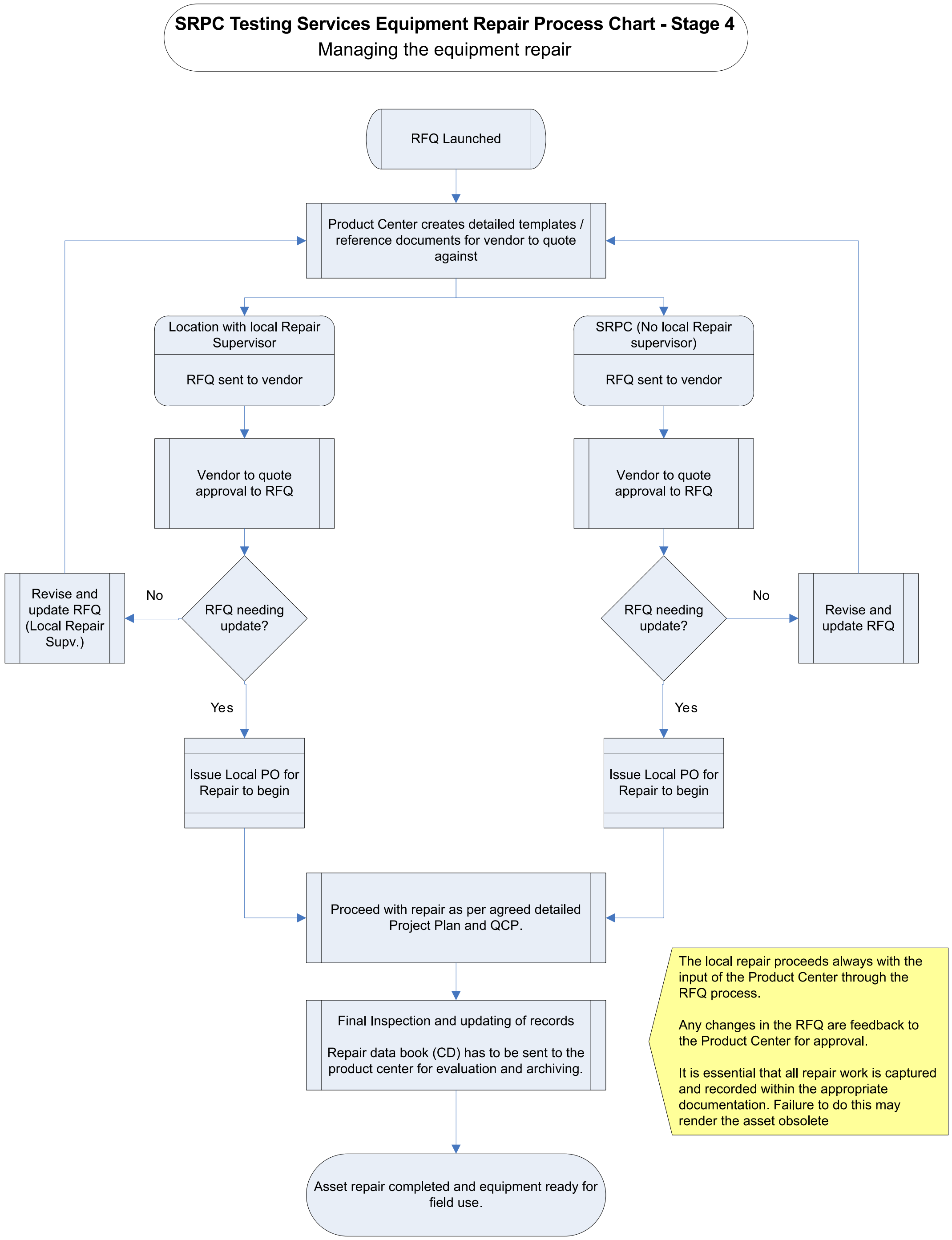


**Figure C-4: SRPC Testing Services Equipment Repair Process Chart - Stage (4)**

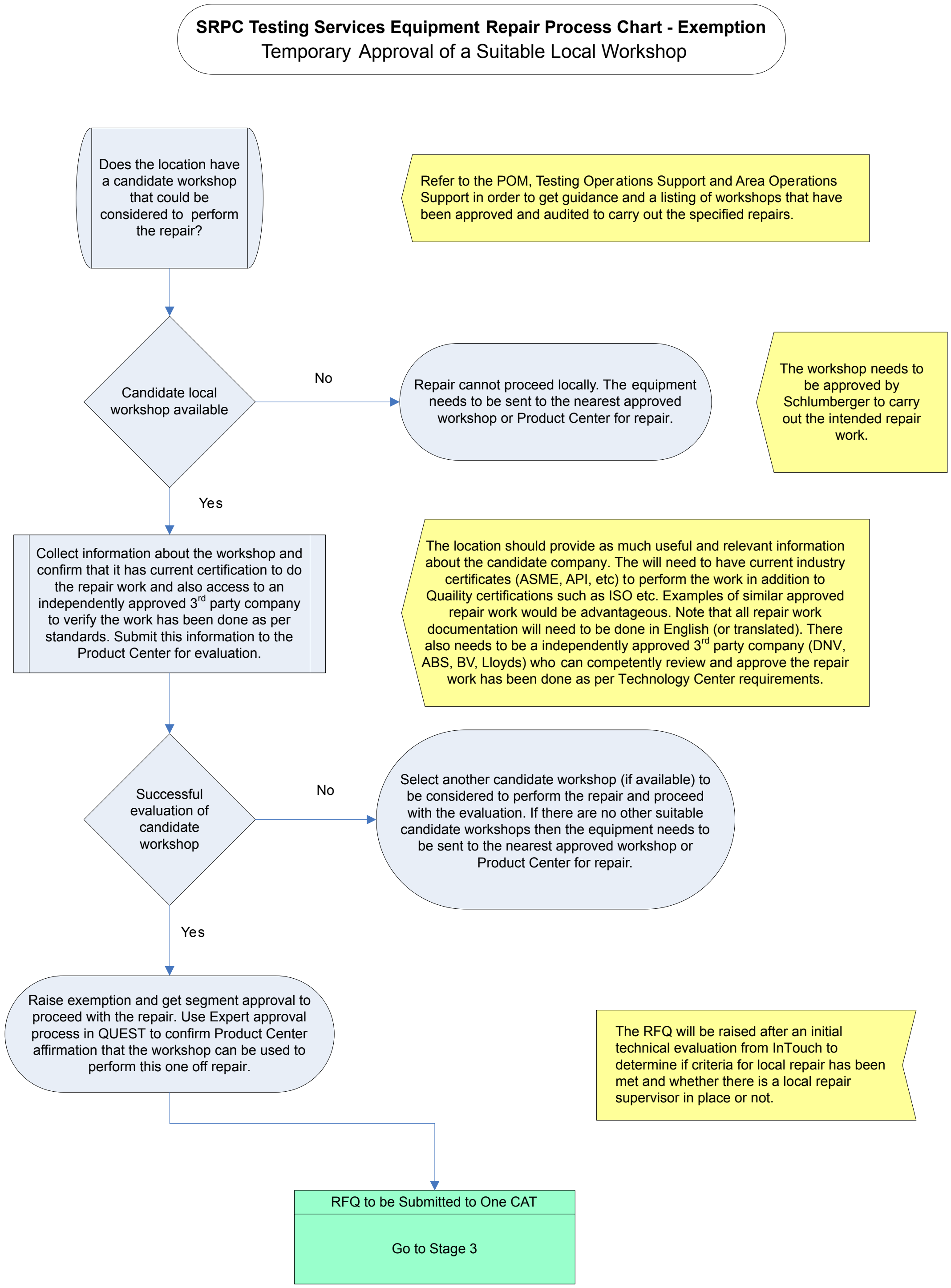


**Figure C-5: SRPC Testing Services Equipment Repair Process Chart - Stage (5)**

# C.9 Appendix C Revision History

For more details see Appendix F.

**Warning** Potential Severity: Serious
Potential Loss: Security
Hazard Category: Human

The controlled source document of this manual is stored in the InTouch Content ID 3045666. Any paper version of this standard is uncontrolled and should be compared with the source document at time of use to ensure it is up to date.

# NACE MR-0175/ISO 15156, Second Edition 2009

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# D NACE MR-0175/ISO 15156, Second Edition 2009

NACE MR-0175/ISO 15156 was last revised in 2009.

Materials for use in environments containing $H_2S$ in oil and gas production.

Hydrogen Sulfide ($H_2S$), also called sour gas, is a poisonous gas which can also deteriorate and destroy the strength of the steel used for pressure containing parts, causing them to fracture while under pressure, with disastrous results.

SSC (Sulfide Stress Cracking) is the brittle failure of the metallic material by cracking under the combined action of tensile stress and corrosion in a water and $H_2S$ environment.

NACE MR-0175/ISO 15156 recommends metallic materials which exhibit resistance to Sulfide Stress Cracking (SSC).

Schlumberger Testing Equipment complies with the metallurgical requirements of NACE MR-0175/ISO 15156. The user is responsible to ensure that the equipment is fit for service in the intended well environment consistent with the intent of the standard.

NACE MR-0175/ISO 15156 defines:

- The environmental conditions in which Sulfide Stress Cracking (SSC) is likely to occur, commonly designated as sour environments.
- The metallic materials and their requirements (heat treatments, etc.) for resistance to SSC, SCC and other forms of environmental cracking related to $H_2S$ exposure.

NACE MR-0175/ISO 15156 does not include design specifications and does not consider other forms of corrosive conditions such as, for instance, weight loss corrosion due to $H_2S$, $CO_2$, $O_2$.

The new ISO 15156 document is divided into three parts:

Part 1: General Principles Section for the Selection of Cracking Resistant Materials.

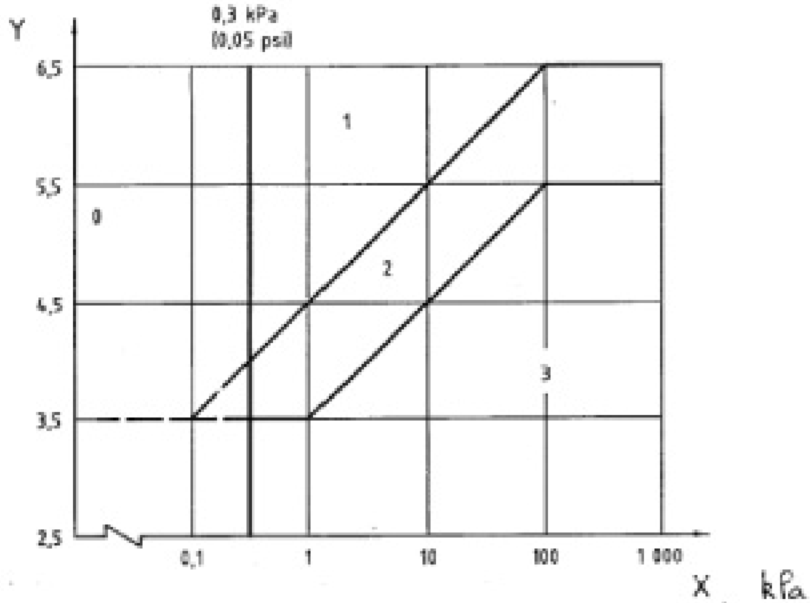
Part 2: Cracking-resistant carbon and low-alloy steels, and the use of cast irons.

Part 3: Cracking-resistant CRAs (Corrosion Resistant Alloys) and other alloys.

The new standard is technically equivalent to NACE MR0175:2003 edition. In 2003 $H_2S$, pH and chloride limits were imposed for many alloys. Thus it is important to know the specific well conditions before selecting materials to be used for permanent equipment. There are special rules for temporary or well service equipment that apply to Schlumberger tools used in testing.

# D.1 Sour Environments Determination

NACE MR-0175/ISO 15156 defines sour environments on the basis of the partial pressure of $H_2S$ in the gas phase. Figure D-1: Sour Environment Severity can be used to assess the severity of the sour environment.




Key
X $H_2S$ partial pressure, kPa
Y *in situ* pH
0 Region 0
1 SSC Region 1
2 SSC Region 2
3 SSC Region 3

**Figure D-1: Sour Environment Severity**

$H_2S$ service resistant materials shall be used when the partial pressure of $H_2S$ in a wet gas phase of a gas or gas condensate or crude oil system is equal or greater than 0.05 psia.

Region 0: Generally, no precautions are required for materials used in these conditions. However, steels that are highly susceptible to SSC and Hydrogen Stress Cracking may crack. These are typically high strength steels above 140 ksi min yield strength.

Region 1: Steels for Region 1 may be selected based on criteria described in Section A.2, A.3 or A.4 in the ISO 15156:2 standard in Annex A.

Region 2. Steels for Region 2 may be selected from Sections A.2 or A.3 in Annex A.

Region 3. Steels for Region 3 may be selected from Section A.2 only in Annex A.

In summary, Region 0 is generally non sour condition.

Region 1 and 2 - certain grades of tubing and tubular components like UNS G41XXO, formerly AISI 41XX are acceptable with hardness higher than 22 HRc, but lower than a hardness which is specific to the grade of material, with proper qualification.

Region 3 - the materials that are listed in ISO 15156 part with hardness and or strength limitations.

In the absence of suitable choices, steels may be qualified by lab testing or documented field experience under the guidelines stated in the standard.

In a mixture of gases, partial pressure of each component is equal to the total pressure multiplied by its mole fraction in the mixture. For most gases, the mole fraction is equal to the volume fraction of the component.

$H_2S$ partial pressure = (total pressure in psia) x $H_2S$ concentration in ppm x 1/1,000,000.

(Note ppm concentration is expressed here in volume percent; 10 ppm = 0.001%)

## *D.2* Metallic Material Requirements

NACE MR-0175/ISO 15156 lists materials that are resistant to SSC in sour environments, provided they are manufactured to the heat treatment and mechanical properties specified.

Material supplied for sour service shall meet the metallurgical requirements including maximum hardness as listed in Table D-1: Maximum Acceptable Hardness Limits.

A measurement of hardness can therefore be used as a field inspection method to verify if a material is suitable for $H_2S$ Service.

As a general guideline, carbon and low alloy steels are acceptable at a maximum hardness of 22 HRC (Rockwell C Hardness Scale units) equivalent to 237 B (Brinell Hardness) for carbon steel and 241 HB for alloyed steels, provided that they have less than 1% mass fraction of Nickel, are not free-machining steels, and are subject to certain heat treatment conditions.

Table D-1: Maximum Acceptable Hardness Limits lists hardnesses for commonly used specialty steels and alloys. For other materials, consult the NACE MR-0175/ISO 15156 to determine the maximum acceptable hardness values.

**Table D-1: Maximum Acceptable Hardness Limits**

| Alloy | Condition | Min YS (ksi) | HRC Max | Cold Worked Alloys | | | |
|---|---|---|---|---|---|---|---|
| 4130/4140 | Q&T | 80 | 22 | 25Cr | CW | 110-140 | 36 |
| 4130 | Q&T | 80 | 22 | 825 | CW | 110-140 | 40 |
| 4140 | Q&T | 80 | 22 | G-3 | CW | 110-140 | 40 |
| 9Cr-1Mo | Q&T | 80 | 22 | C-276 | CW | 110-140 | 40 |
| 13Cr/420 | Q&T | 80-85 | 22 | | | | |
| L80 13Cr - 5CT | Q&T | 80-85 | 23 | | | | |
| Super 13Cr | Q&T | 95 | 27-28 | | | | |
| UNS S17400 | ST/Dbl age | 105 | 28–31 | | | | |
| Alloy 316 | Ann. | 30 | 22 | | | | |
| Alloy 450 | Ann/Age | 95 | 31 | | | | |
| Ann 25Cr | Ann | 80 | 28 | | | | |
| Alloy 925 | Ann/Age | 110 | 38 | | | | |
| Alloy 718 | Ann/Age | 120 | 40 | | | | |
| Alloy 725 | Ann/Age | 120 | 43 | | | | |
| Alloy 625 Plus | Ann/Age | 120 | 43 | | | | |
| Alloy 625 Plus | Ann/Age | 140 | 43 | | | | |
| X-750 Spring | Ann/Age | See Spec | 50 | | | | |
| MP35N | CW&A | 200 | 51 | | | | |
| MP35N Spring | CW&A | See Spec | 55 | | | | |
| Elgiloy Spring | CW&A | See Spec | 60 | | | | |

Sufficient number of hardness tests shall be made to establish the actual hardness of the material. Individual hardness readings exceeding the value permitted can be considered acceptable if the average of several readings taken does not violate the value permitted and no individual reading is greater than 2 Rockwell C (HRC) scale unit above the acceptable value.

When warranted, Brinell (HB) or other hardness scales may be used.

## D.3 Alloy Limits

Table D-3: Material Limits lists the $H_2S$, chloride, pH and temperature limits for commonly used alloys in Schlumberger. For alloys not listed here, consult the standard.

Table D-2: Conditions for 17-4PH lists the conditions under which 17-4PH may be used in testing tools subject to certain heat treatments which are required. Fluid sampling containers can be used to store sour oil without restriction. If water is present, then the pH should be equal to or greater than 4.5, and the $H_2S$ partial pressure less than 0.5 psi for short term or long term storage.

**Table D-2: Conditions for 17-4PH**

| | | | | | |
|---|---|---|---|---|---|
| **Formation Testing Tools** | | | | | |
| 17-4PH[1] | 105 Min YS (ksi) | Not sp | Not sp | Not sp | Not sp |
| **Fluid Sampling Containers**[2] | | | | | |
| 17-4PH | 105 Min YS (ksi) | 4.5 mg/l | Not sp | Not sp | 0.5 psi |

[1] 17-4PH shall be used under conditions where it is stressed at less than 60% of the minimum specified YS Environmental limits have not been established.

[2] 17-4PH has been used successfully for sample bottles and containers. Continued use in environments beyond those listed in NACE MR-0175 has been documented according to the procedures in Section 16 in 2003 edition of MR-0175. Information has been sent to NACE and was made public.

Certain alloys like 316 SS, 825 and components are listed without environmental restriction such as 316 SS control line, fittings, screens, etc. Similarly, Monel is listed for gas lift application and for non pressurized components. Please review the document for lack of restriction on a specific component. Consult materials engineering expert for a specific sour environmental application if not sure about the specific application.

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**Table D-3: Material Limits**

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | MR0175 Limits | | | | | |
| | | | | | | | | Schlumberger Recommendation | | | | | |
| | | | | | | | Temp/$H_2S$ Limits | | | | | | |
| Material | Min YS (ksi) | | pH Limit | Chloride Limit (mg/l) | Temp Limit Deg F | $H_2S$ Limit PSI | <200°F | 250°F | 275°F | 300°F | 350°F | 400°F | 450°F |
| 4130/4140 | 80 | | not sp | not sp | not sp | not sp | | | | | | | |
| 9Cr-1Mo | 80 | | not sp | not sp | not sp | not sp | | | | | | | |
| 13Cr | 80/85 | | ≥3.5 | not sp | not sp | 1.5 psi | | | | | | | |
| | | SLB Limit | 4 | 100,000 | | 1.5 psi | | | | | | | |
| 17-4 PH SS | 105 | | ≥4.5 | not sp | not sp | 0.5 | | | | | | | |
| | | | ≥4.5 | not sp | | 0.5 | | | | | | | |
| Alloy 450 | 95 | | ≥3.5 | not sp | not sp | 1.5 psi | | | | | | | |
| | | SLB Limit | 4 | 100,000 | | 1 psi | | | | | | | |
| S-13Cr-95 | 95 | | ≥3.5 | not sp | not sp | | | | | | | | |
| | | SLB Limit | ≥4 | | 350°F | 1 psi | | | | | | | |
| S13Cr-110 | 110 | SLB Limit | Not in MR 0175 | | | | | | | | | | |
| | | | ≥4.5 | | | 0.05 psi | | | | | | | |
| Ann 316SS | 30 | | not sp | not sp | 140°F | 15 | | | | | | | |
| | | | | if <50 mg/l | 140°F | 50 | | | | | | | |
| Ann 25Cr | 80 | | not sp | not sp | | 3 | | | | | | | |
| CW 25Cr | 110-140 | | not sp | 120,000 | not sp | 3 | | | | | | | |
| 718/925 | 120/110 | | not sp | not sp | 275°F | | | | no limit | | | | |
| | | | | | 300°F | | | | | 400 psi | | | |
| | | | | | 390°F | | | | | | | 330 psi | |
| | | | | | 400°F | | | | | | | 200 psi | |
| | | | | | 450°F | | | | | | | | 30 psi |
| 725/625 Plus | 120 | | not sp | not sp | 350°F | | | | | | no limit | | |
| | | | | | 400°F | | | | | | | 600 psi | |
| | | | | | 425°F | | | | | | | 300 psi | |
| | | | | | 450°F | | | | | | | | 150 psi |
| Ann Ni Alloys | 35 | | not sp | not sp | not sp | | | | | | | | |
| CW C-276 | 180 max | | not sp | not sp | 400°F | | | | | | | no limit | |
| | | | | | 450°F | | | | | | | | 1000 psi |
| CW&A MP35N | 200 | | not sp | not sp | not sp | | | | | | | | |

## D.3.1 The API Specification Reference to NACE MR-0175 for the Selection of Materials

Our testing equipment is designed for $H_2S$ service in compliance with API Specification 6A for high pressure equipment (WP > 5000 psi) or with ASME/ANSI and API RP 14E for low pressure equipment (WP < 5000 psi).

API6A 17th edition: refer to Material Requirements Table D-3: Material Limits.

The material for $H_2S$ is classified as Class DD, EE, FF.

When no weight loss is anticipated, Schlumberger Testing will use (mainly for bodies) a Class "DD" material which is a carbon or a low alloy steel.

Class "EE" calls for bodies made of carbon or low alloys steels and pressure bearing parts made of stainless steels. Class EE may be used when $CO_2$ is present, for a better resistance to weight loss corrosion.

Class FF is all stainless steel.

## D.3.2 Effect of Temperature on Resistance to SSC

As a general rule, the resistance of a metallic material to SSC increases when the temperature increases. For instance, high tensile grades of tubing can be used at elevated temperature: above 175°F [80°C] for N80, P105, P110.

Equipment design should give consideration for drop in yield strength at elevated temperatures and equipment pressure rating must be adjusted accordingly for services above 200°F.

# D.4 Recovery

When the equipment is no longer subjected to the $H_2S$ environment (upon completion of the operation) and after a certain time, the hydrogen trapped in the steel migrates out through the structure and is released to the atmosphere. The detrimental effect of hydrogen will be lesser over a period of time.

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**Note**
High temperature will accelerate the recovery rate: about three hours at 350 °F is equivalent to two days at 70 °F.

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The migration speed of hydrogen is also increased at high temperature (above 80 °C) and the time needed to evacuate the hydrogen from the steel is reduced.

## *D.5* Appendix D Revision History

For more details see Appendix F.

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**Warning** Potential Severity: Serious
Potential Loss: Security
Hazard Category: Human

The controlled source document of this manual is stored in the InTouch Content ID 3045666. Any paper version of this standard is uncontrolled and should be compared with the source document at time of use to ensure it is up to date.

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# Reservoir Sampling and Analysis $H_2S$ Standard

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# E Reservoir Sampling and Analysis $H_2S$ Standard

## E.1 Statement of Standard

Hydrocarbons are being sought and discovered over a wider geographical area than ever before and reservoir formations containing Hydrogen Sulfide ($H_2S$) are now being routinely sampled and analyzed by Testing Services.

Testing Services operations encompassing Reservoir Sampling and Analysis (RSA) services can be conducted safely if the $H^2S$ hazard is recognized, understood and the appropriate measures taken to ensure safe operations.

## E.2 Objective

To ensure that all Testing Services Reservoir Sampling and Analysis locations are adequately prepared to deal with the risks associated with reservoir fluid samples containing $H_2S$ and that risks are effectively managed to be as low as reasonably practicable for all Schlumberger and contractor personnel.

## E.3 Scope

This standard compliments SLB-QHSE-S015 $H_2S$ (Hydrogen Sulfide) Standard and establishes the minimum expectations for the conduct of our operations and the protection of life when dealing with reservoir fluid samples containing $H_2S$. This standard shall apply at all times to all Schlumberger employees working for or on behalf of Schlumberger on Testing Services Reservoir Sampling and Analysis facilities and locations where $H_2S$ may be present.

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**Note**
For all wellsite Reservoir Sampling and Analysis operations the Schlumberger SLB-QHSE-S015 $H_2S$ (Hydrogen Sulfide) Standard must be adhered to at all times.

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This standard is not intended to be a design specification or technical reference for hardware or in material selection for $H_2S$ service. The standard is principally intended to address operations being conducted at reservoir fluids analysis locations and facilities where $H_2S$ containing reservoir fluid samples may be handled, analyzed or stored.

Operations pertaining to reservoir sampling and analysis $H_2S$ operations include sample handling, restoration, transfer, analysis, storage, blow down, transportation and disposal.

It is recognized that Health and Safety related criteria may differ according to local, state or national regulations. All locations must follow Schlumberger standards as well as client standards and international or local regulations in case of conflict, the stricter requirements apply.

# E.4 Implementation and Monitoring

## E.4.1 Key Definitions

| Term | Definition |
|---|---|
| **$H_2S$** | Hydrogen Sulfide otherwise know as Hydrogen “Sulphide”, “Sour Gas”, “Acid Gas” along with other names, is an extremely toxic, colorless gas, which is heavier than air and soluble in both water and liquid hydrocarbons. $H_2S$ has an odor of rotten eggs at small concentrations (<1 ppm) however at higher concentrations olfactory nerves become temporarily paralyzed and it cannot be detected by smell alone. $H_2S$ can be naturally occurring, can be produced by sulfate-reducing bacteria, and can be generated by reaction of HCL acid and iron-sulfides (sulfide scale) found on the well tubular. $H_2S$ occurs worldwide in various concentrations associated with gas, oil and water.<br><br>**Note**<br>See section Appendix E.6: $H_2S$ Characteristics and Units of Measurement for additional details on $H_2S$ characteristics and units of measurements. |
| **Sample** | Samples may include but are not limited to, pressurized reservoir fluid (oil, gas and water) samples, dead/atmospheric crude oil, water, completion and drilling fluid samples and all sub-samples that may be created at the wellsite or within the Fluids Analysis Laboratory. |
| **$H_2S$ “not suspected” Sample** | A $H_2S$ “not suspected” sample is a sample where previous compositional analysis, Well Testing, Wireline or Production operations have confirmed the absence of $H_2S$. |

| | |
|---|---|
| **$H_2S$ "known" Sample** | A $H_2S$ "known" sample is one where compositional analysis, well testing or production operations information is available and confirms the presence of $H_2S$. Locations immediately adjacent to formations, zones or blocks designated as $H_2S$ areas shall be assumed to be $H_2S$ areas until proven otherwise. |
| **$SO_2$** | Sulfur Dioxide (also Sulphur Dioxide…) is a heavy colorless gas with a specific gravity 2.25 times that of air.<br><br>Though $SO_2$ does not burn, it is highly corrosive when mixed with water and only slightly less toxic than hydrogen sulfide.<br><br>The odor threshold for $SO_2$ is 0.3 - 1 ppm. Exposure to $SO_2$ can cause breathing difficulties, inflammation of respiratory organs and irritation of eyes due to the formation of sulphurous acid on moist mucous membranes.<br><br>At higher concentrations $SO_2$ can cause long term damage to eyes, skin and lungs and also give rise to delayed potentially fatal fluid accumulation and swelling in the lungs. |
| **Partial Pressure** | Partial pressure, in the context of this standard, may be used to establish the integrity of a system that was not specifically designed for $H_2S$ service when such a system is subsequently exposed to $H_2S$.<br><br>The total pressure in a system is equal to the sum of the individual partial pressures of the gas fractions in a mixture i.e. the pressure of a gas in a mixture is equal to the pressure it would exert if it occupied the same volume alone at the same temperature. To calculate partial pressure in a system therefore we must consider the mole % of gas and the total measured pressure of the system in absolute terms (or at bubble point pressure if the fluid under consideration is contained above bubble point pressure). Therefore:<br><br>• Partial pressure equals the mole % multiplied by total system pressure in units absolute.<br><br>For example, if the total system pressure is 1000 psia and mole % is 1%, then the partial pressure equals 1000 × 1/100 = 10<br><br>• Partial pressure divided by total pressure multiplied by 1,000,000 will give you ppm of $H_2S$ by volume (and ppm multiplied by system pressure divided by 1,000,000 to obtain partial pressure).<br><br>Example A. 10 mole % $H_2S$ within a system at 1000 psia = 100 psia partial pressure (10/100 × 1000).<br><br>Example B. 10 psia partial pressure within a system at 10,000 psia = 1000 ppm (10/10000 × 1e6).<br><br>Example C. 50 ppm within a system at 1,000 psia = 0.05 psia partial pressure. |
| **Sulfide Stress Cracking** | SSC (Sulfide Stress Cracking) is the brittle failure of the metallic material by cracking under the combined action of tensile stress and corrosion in an $H_2S$ environment. It can deteriorate and |

destroy the strength of the steel used for pressure containing parts, causing them to fracture while under pressure, with disastrous results.

## E.4.2 Responsibilities

Schlumberger Testing Services Line Management is responsible for:

- Maintaining accurate information about the presence of $H_2S$ in their area of operations. Within Testing Services RSA, operational areas may include Fluids analysis laboratories, Rock laboratories, sample restoration areas, sample storage areas, workshops, sample bleed down areas and any other areas within the facility where samples and sub-samples containing $H_2S$ may be located, transported or stored even on a temporary basis. This information shall be defined on a site plan, posted in the location and communicated to all personnel.
- Adequate warning signage must be posted in all $H_2S$ areas to alert personnel to the possibility of the presence of $H_2S$.
- Ensuring all Sample bottles and receptacles in storage containing > 10 ppm $H_2S$ are labelled with a Toxic/$H_2S$ Hazard label to identify hazardous nature of contents.
- Having an up to date database of all reservoir fluid samples on location, including $H_2S$ concentration and storage location.
- Ensuring that risk assessments (HARCs) are defined and all identified risk prevention and mitigation measures are implemented for all operational workflows and operational areas that may encounter $H_2S$ in Testing Services RSA locations.
- Ensuring that Schlumberger shall adhere to regulatory authority and Client standards, procedures and/or practices where they are enforced and are the more demanding.
- Ensuring all personnel including contractors are trained to a sufficient level of competency for handling $H_2S$.
- Having an up to date and tested Testing Services location Emergency Response Plan which must encompass personnel evacuation routes from all RSA operational areas including Fluids analysis laboratories, Rock laboratories sample restoration areas, sample storage areas, workshops, sample bleed down areas and any other areas within the facility where samples and sub-samples containing $H_2S$ may be located, transported or stored even on a temporary basis.
- Maintaining a register of all location $H_2S$ safety equipment including alarms, detectors, extraction systems, breathing air systems, escape packs.

- Defining, implementing and maintaining a location schedule of maintenance, certification and calibration for all location $H_2S$ safety equipment including alarms, detectors, extraction systems, breathing air systems, escape packs.
- Ensuring that Testing Services Reservoir Sampling and Analysis facilities are constructed to a standard that reduces risk of $H_2S$ exposure to personnel to as low as reasonably practicable via proper engineering, isolation, extraction and ventilation controls.
- Ensuring that Testing Services Reservoir Fluid Sampling and Analysis facilities are fitted with adequate $H_2S$ detection and alarms systems in order to detect and alert to the presence of $H_2S$ in all RSA $H_2S$ operational areas.
- Ensuring all sample bleed down operations are conducted using validated methods and in a way to minimize exposure of $H_2S$ to both personnel, operational areas and the environment.
- All waste residues arising from all sample disposal and bleed down operations are handled through a Schlumberger approved waste management company and in strict accordance with Schlumberger Environmental Standards and any applicable local, state or national regulations.
- Ensuring that Schlumberger supplied $H_2S$ safety equipment is available, operative and fully tested and that only qualified personnel or a qualified service center carries out maintenance of equipment using original manufacturers parts.
- Fit testing of SABA and SCBA masks is carried out to ensure all personnel have the correct size mask available.
- Operational judgment when $H_2S$ is found to be present below a concentration of 50 ppm either in solution in sour crude samples or as free gas in reservoir fluid samples. Refer to the Section Appendix E.4.3.3: Operational considerations for Reservoir Sampling and Analysis operations for samples with $H_2S$ concentrations <50 ppm for guidance.

## *E.4.3* $H_2S$ Operations in Testing Services Reservoir Sampling and Analysis Locations

### *E.4.3.1* Operational Areas in Reservoir Sampling and Analysis Locations

Reservoir Fluid Sampling and Analysis locations regularly handle reservoir fluid samples containing $H_2S$. $H_2S$ content can vary from few ppm to very high concentrations at % levels. Proper risk prevention and mitigation measures as identified during definition of HARCs shall be implemented in all operational areas. These areas can generally be divided into:

- Fluids Analysis Laboratory
  - Sample Restoration Areas
  - PVT Analysis Areas
  - Compositional Analysis Areas
  - Wet Chemistry Areas
- Rock Analysis Laboratory
  - Core flood where crude oil or live oil is being used
  - EOR studies where crude oil or live oil is being used
- Sample Storage Areas and Rooms
- Lab Cabins (e.g. for PVT Express and Wellsite Analysis)
- Sample Blowdown Areas
- Workshop Facilities (e.g. for Sample Bottle and Tool Redressing)

## *E.4.3.2* General

Basic detection and measuring devices (e.g personal monitors) need to be provided in all Testing Services Reservoir Sampling and Analysis operational areas at all times (whether $H_2S$ is suspected from a sample or not).

Designated $H_2S$ areas within Testing Services Reservoir Sampling and Analysis locations shall be assigned for handling or storing all reservoir fluids samples and sub-samples which contain $H_2S$ concentrations greater than 10 ppm. $H_2S$ safety equipment shall be deployed on site in all Testing Services Reservoir Sampling and Analysis facilities along with trained and competent persons and an operational plan taking full account of the presence of $H_2S$.

$H_2S$ safety items will be as described below in Section Appendix E.4.3.4: Safety Equipment.

Personnel conducting $H_2S$ operations are forbidden to work alone and must always work using a “Buddy System” i.e. there is always a minimum of one other $H_2S$ Level 2 trained person available in a safe area with emergency equipment available to oversee the operations being carried out in case of an emergency situation arises in which assistance would be required.

All efforts should be taken into determining the $H_2S$ levels in all samples and sub-samples received by the laboratory, these efforts should include and not limited to:

- Sample Data Sheets from Wireline or Testing Sampling Operations.

- Sampling Field Operations Reports.
- Client provided information.
- Reservoir Fluids Data from previous fluids analysis studies on the same zone of the reservoir.

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**Note**

There may be occasions when the $H_2S$ level of samples is unknown and has not been determined. In this situation the client must be contacted to gain permission in order to perform $H_2S$ analysis.

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No work is permitted on any reservoir fluid samples where the $H_2S$ content is unknown without provisions of a minimum of $H_2S$ safety equipment.

Minimum equipment means $H_2S$ detectors, measuring equipment and Self Contained Breathing Apparatus (SCBA) until such time as $H_2S$ concentration is accurately determined.

Work decision criteria for all Reservoir Sampling and Analysis location operations as defined in Table E-1: Work Decision criteria for Reservoir Fluid Samples Containing $H_2S$ in RSA Locations and Table E-2: Work Decision Criteria for $H_2S$ in Air in RSA Locations must be adhered to at all times.

### E.4.3.3 Operational considerations for Reservoir Sampling and Analysis operations for samples with $H_2S$ concentrations <50 ppm

Operational Judgment is required when $H_2S$ is found to be present during work activities either in solution in “Sour” reservoir fluid samples or as free gas either in-stream (contained within an enclosed system e.g. tubing, PVT cell, sample bottle, etc) or as free gas in atmosphere (breathable air in the vicinity of the work area) as to when to start using $H_2S$ safety equipment. It is recommended practices for low concentrations (< 50 ppm) of $H_2S$ to follow the following:

- Where in Stream $H_2S$ concentrations are found during reservoir sampling and analysis activities to be above 20 ppm; if the fluid and gas are contained in a closed system i.e where no sample venting or leakage can occur (e.g. in a enclosed system such as a sample bottle or PVT Cell), operations may be continued until the measured in-stream $H_2S$ concentrations reaches a level of 50 ppm. If the concentration is above 50 ppm , work will be suspended until $H_2S$ safety equipment and qualified personnel are deployed.

- In case of venting free gas in atmosphere (i.e flashed gas, DV gas, sample transfers, sample bleed down operations etc.) where $H_2S$ concentrations are greater than 10 ppm in atmosphere, ongoing work shall be suspended as soon thereafter as operational and safety considerations allow, and shall remain so until $H_2S$ safety equipment and qualified personnel are deployed. For $SO_2$ the limit shall be reduced to 2 ppm.
- In the case of venting free gas in atmosphere (i.e flashed gas, DV gas, sample transfers etc..) where $H_2S$ concentrations between 0 ppm and 10 ppm in atmosphere a line management decision must be made whether the operation can start, continue or be terminated under prevailing circumstances. Consideration must be given to expected duration, means and direction of escap, ventilation, extract and particularly possibility of stacking (build up) in low lying areas.
- If, in consideration of the above, a line manager cannot provide acceptable justification, in the prevailing circumstances, for performing the planned operations the default must be to action an assuredly safe option i.e. suspend operations, deploy necessary $H_2S$ safety equipment and personnel.

**Table E-1: Work Decision criteria for Reservoir Fluid Samples Containing $H_2S$ in RSA Locations**

| **Type of $H_2S$ presence encountered in Reservoir Fluid Samples** | | |
|---|---|---|
| **Measured $H_2S$ Concentration** | **Controlled working environment** (e.g. handling and operating closed systems such as Sample Bottles or PVT Cell ie.no venting) | **Uncontrolled $H_2S$ Release** (e.g. venting of sample to atmosphere) |
| Less than 20 ppm in sample | Work normally | Work allowed at discretion of line manager , monitor $H_2S$ continuously, SCBA must be available for rescue* |
| From 20 ppm to 50 ppm in sample | Work allowed to continue , sample is under observation, SCBA available for rescue* | Suspend work until $H_2S$ equipment is deployed , monitor $H_2S$ continuously , use SCBA for short term work , use SABA for continuous work |
| More than 50 ppm in sample | Suspend work until $H_2S$ equipment is deployed , monitor $H_2S$ continuously , use SCBA for short duration, use SABA for continuous work | Suspend work, vacate area unless $H_2S$ equipment is deployed , use SCBA for rescue only* , use SABA for continuous work |

* Rescue operations shall only be undertaken with $H_2S$ safety equipment and by personnel trained in $H_2S$ Emergency Response.

**Table E-2: Work Decision Criteria for $H_2S$ in Air in RSA Locations**

| Type of $H_2S$ presence encountered in Air | | |
|---|---|---|
| **Measured $H_2S$ Concentration** | **Controlled working environment** (e.g. Fluids Analysis Laboratory, $H_2S$ Room, Sample Venting Area, Sample Storage Area) | **Uncontrolled $H_2S$ Release** |
| Less than 10 ppm in air ( Note: 2 PPM for $SO_2$) | Work time is restricted to <8 hrs , recovery period after exposure, monitor $H_2S$ continuously | Work allowed at discretion of line manager , monitor $H_2S$ continuously, SCBA must be available for rescue* |
| From 10 ppm to 20 ppm in air | Exposure limited to <10 min, suspend work, vacate area, unless $H_2S$ equipment is deployed use SCBA for short duration , use SABA for continuous work | Suspend work until $H_2S$ equipment is deployed , monitor $H_2S$ continuously , use SCBA for short term work , use SABA for continuous work |
| More than 20 ppm in air | Suspend work until $H_2S$ equipment is deployed, monitor $H_2S$ continuously , use SCBA ( for rescue only) , use SABA for continuous work | Suspend work, vacate area unless $H_2S$ equipment is deployed , use SCBA for rescue only* , use SABA for continuous work |

* Rescue operations shall only be undertaken with $H_2S$ safety equipment and by personnel trained in $H_2S$ Emergency Response

## E.4.3.4 Safety Equipment

### Supplied Air Breathing Apparatus (SABA)

Supplied Air Breathing Apparatus (SABA) is the Schlumberger recommended option for continuous work in an $H_2S$ environment such as Reservoir Analysis Laboratories.

Cascade system: Comprising air supply for SABA consisting of a cascade system of hoses connected to a main set of bottle banks for continuous supply. These banks are either exchanged for new ones, or can be recharged locally with dedicated breathing air compressor.

Breathing air high-pressure compressors: Compressor must be certified as breathing air compressor and capable of delivering a minimum of 15 cft/mn, or 500 l/mn, at a working pressure of 3000 psi. The air supplied shall meet or exceed air quality requirements of standards EN 12021 or ANSI/CGA G-7.1grade "D". Air quality shall be tested and test results recorded.

The SABA used by the individual users shall have as a minimum a 20 minute SCBA capability immediately functional (automatic or manual change over) upon failure or disconnect of the SABA cascade system to allow time for completion of critical work activities and escape to a safe area.

**Self Contained Breathing Apparatus (SCBA)**

Self Contained Breathing Apparatus (SCBA) may only be used for continuous work when the supply hoses from a (SABA) system would constitute an unacceptable hazard or significantly impede operations, as documented in the HARC form.

Persons in or adjacent to the work area but who are not required to utilize breathing apparatus for their duties shall wear portable $H_2S$ gas detectors (or be in accompanied by an individual so equipped) and an Escape Pack.

**Escape Packs**

An Escape Pack is a portable breathing apparatus with a minimum of 5 minutes (10 minutes recommended) breathable air supply to allow escape from $H_2S$ areas to fresh air. Use of an escape pack for work in place of SABA or SCBA is strictly forbidden.

## *E.4.3.5* Facial Hairs

For all breathing apparatus to be effective, it is critical to have an effective seal around the face mask. Given that facial hairs may prevent this seal, it is recommended to prohibit facial hairs for personnel working in known $H_2S$ areas.

## *E.4.3.6* $H_2S$ Detection Systems

Fixed gas detection systems. A main control panel in an area with 24 hour manning coverage with remote sensors in strategic areas around installations for continuous monitoring of the concentration of combustible gases and $H_2S$ in atmosphere. The systems are to be fitted in work areas housing major assets e.g. PVT cells, restoration benches, gas chromatogram equipment, wet chemistry lab and sample storage areas where $H_2S$ is expected. They shall have audible and visual low and high alarms set at 10 ppm and 20 ppm respectively. It is recommended that all fixed $H_2S$ detection systems have back up power supply.

Portable electronic gas detectors: A hand portable device with a clear audio visual display with alarm and settings for 10 ppm of concentration. The device must be able to determine oxygen content in air, level of combustible gases in air and level of $H_2S$ in air. Detectors must have means for calibration, a valid calibration certificate, and have accessories for remote detection (especially for confined space entry). Personnel shall be trained in their application, proper use, and any operational limits that may be applicable. Detectors shall not be used as measuring devices.

$H_2S$ sampling should be carried out with chemical reactive tubes of “Gastec” type, UOP/ASTM type titration measurement, or electronic sensing device where the accuracy is similar or better to the chemical means.

## E.4.3.7 RSA Facility Exhaust and Ventilation Systems

Facility exhaust and ventilation systems: Reservoir Sampling and Analysis operational areas including Fluids Analysis Laboratories, $H_2S$ Rooms and Sample Storage areas shall be fitted with adequate fixed exhaust and ventilation systems in order to minimize build-up of $H_2S$, hydrocarbons and odors in the working environment and to maintain a clean and safe workplace atmosphere to a level as low as reasonably practicable and within exposure limits. Fixed exhaust and ventilation systems may include fixed laboratory and room extracts and fume cupboards. Localized extract and ventilation including flexible trunking may also be employed e.g. directly above transfer liners during sample handling operations. $H_2S$ Scrubbing Systems should be employed to minimize potential $H_2S$ concentrations released to atmosphere from ventilation and extract systems to within all applicable local, state and national regulatory Air Quality regulatory requirements. Exhaust and ventilation systems must be tested for efficiency and preventative maintenance conducted to ensure minimum exhaust rates are maintained. Personnel shall be trained in their application, proper use and testing.

## E.4.3.8 Schedule of Testing $H_2S$ Safety Equipment and Systems

**Personnel Safety Equipment**

All personnel $H_2S$ safety equipment including SABA, SCBA, Personnel monitors and alarms shall be tested prior to each use i.e.prior to entering any $H_2S$ operational areas or conducting any work during which $H_2S$ may be suspected or encountered.

**$H_2S$ Detection and Alarms Systems**

All facility fixed $H_2S$ alarm systems shall be tested at a minimum frequency of once per week.

All $H_2S$ detection equipment shall be calibrated at a minimum frequency of once per year.

All tests must be recorded and maintained in assets files in the location.

**Facility Extract and Exhaust Systems**

All facility extract and exhaust systems shall be checked for operational readiness daily or prior to each shift commencing to ensure they are operational.

Air Flowrates from fumecupboards shall be checked and recorded weekly.

Smoke Tests shall be conducted at a minimum frequency of every 6 months.

## E.4.4 Implementation

### E.4.4.1 Hazard Analysis and Risk Control (HARC)

Prior to start up for any new Reservoir Sampling and Analysis operation with $H_2S$ suspected or $H_2S$ known samples, a full HARC analysis must be carried out. This must be documented in QUEST.

The risk assessment shall encompass all operational areas which may include Fluids analysis laboratories, Rock analysis laboratories, sample restoration areas, sample storage areas, workshops, sample bleed down areas and any other areas within the facility where samples and sub-samples containing $H_2S$ may be located, transported or stored even on a temporary basis.

Engineering calculations or design simulation software may be used to simulate $H_2S$ dispersal in air upon release from sample receptacles for risk analysis purposes e.g. for designing exhaust and ventilation systems in fluids analysis laboratories and sample storage areas. These calculations shall be performed by engineering experts in gas dispersal and exhaust and ventilation system design. Consideration must be given to all potential $H_2S$ leak mechanisms, density of $H_2S$, expected concentrations of $H_2S$, hydrocarbon release, facility airflows. Example sample receptacle volumes for $H_2S$ release simulations are given in Table E-3: Example Sample Receptacle Volumes.

**Table E-3: Example Sample Receptacle Volumes**

| Sample Receptacle | GSB-LD20 | SSB-IB | CSB-IB | SPMC-20 | MPSR |
|---|---|---|---|---|---|
| Volume (cc) | 20000 | 600 | 600 | 250 | 450 |

## *E.4.4.2* Expert Assistance

For all RSA locations, review and training of our $H_2S$ planning, procedures, and safety equipment deployment shall be performed by 3rd party specialized companies, who are qualified and approved by internationally recognized bodies or local, state or national regulatory authorities to perform such work. Where such a company is not locally available, arrangements shall be made to contract such expertise from another area where such expertise exists.

These reviews shall be undertaken prior to start up of any operations involving handling, analysis or storage of any samples containing $H_2S$ and at a minimum frequency of every 2 years thereafter. Expertise shall be employed during the design of facility exhaust and ventilation systems.

It is recommended that Local Emergency Services are consulted when defining location emergency response and facility re-entry procedures with respect to $H_2S$ and hydrocarbon releases.

## *E.4.4.3* Training and Competency

Training shall meet all applicable Schlumberger, Client, local rules and regulations and applicable international standards. Individuals shall be certified competent by Schlumberger procedure and/or third party specialist review. $H_2S$ certification requirement and training date shall be recorded in QUEST for all applicable individuals.

Schlumberger training requirements:

- A qualified instructor must certify all personnel working in $H_2S$ areas to Schlumberger $H_2S$ level 2.
- Personnel with any risk of coming into contact or of being exposed to $H_2S$ must have completed Schlumberger $H_2S$ level 1. By default this shall include all persons involved in any PVT cell, compositional analysis, wet chemistry, restoration, storage and movement of samples or any laboratory activities. Non- suspected $H_2S$ samples shall not be regarded as zero risk.

## *E.4.4.4* Exposure

Exposure to $H_2S$ shall be strictly controlled so that no employee can be exposed to a concentration greater than the industry recognized time-weighted average Threshold Limit Value (TLV) of 10 ppm in atmosphere for an 8 hour day, in any 40 hour week or to an exposure of no more than a ceiling Short Term Exposure

Limit (STEL) of 20 ppm for a period of 10 minutes with no more than four occurrences in any 8 hour period, or a peak STEL of 50 ppm for a period of 10 minutes as a single occurrence. Persons so exposed shall be immediately removed from possible further exposure for a period of at least five times the duration of the exposure or 40 hrs in the event of a peak exposure event. Persons with medical conditions shall obtain medical advice prior to possible exposure to $H_2S$.

For $SO_2$ the time-weighted average Threshold Limit Value shall be limited to 2 ppm for an 8 hour day with a ceiling Short Term Exposure Limit of 5 ppm as a single occurrence.

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**Note**

Local Government Regulations shall take precedence, where they are more stringent than the above e.g. Exposure Limit - Time Weighted Average of 7 ppm $H_2S$ in an eight hour period.

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## E.4.4.5 Emergency Response

**Emergency Response Plan for Testing Locations:**

Each Testing Services location which handles analyses or stores any $H_2S$ containing samples shall have a formal written $H_2S$ Emergency Response Plan (ERP). The ERP shall include a site contingency plan, which must be posted at key points on the location and communicated to all staff working in the vicinity of $H_2S$ operational areas.

Site contingency plans for shut in and evacuation must be read and understood by site Supervisors and communicated to all personnel present at the worksite prior to commencing operations.

The $H_2S$ contingency plan shall give clear instructions to all personnel on what action is to be taken in the event of an H2S emergency. These instructions shall include:

- The location of safe breathing areas depending on wind direction; and extract location.
- The location of $H_2S$ protective equipment.
- The identification of the alarm sound and visual displays.
- The search and rescue procedures.
- Location search and rescue map; locate all $H_2S$ possible areas.
- The evacuation procedures.

- The communication procedure.
- The specific assignments and duties of all personnel.

**Frequency of Drills**

The location ERP shall be tested periodically by performing drills. When considering minimum frequency of drills, it should be noted that fluids analysis laboratory facilities are staffed with permanent staff unlike wellsite facilities.

- Drills shall be held at least on a monthly basis when any $H_2S$ samples or sub-samples are on location.
- The drills shall be pre-planned and shall emphasize the key learning point(s).
- The drills shall be held on varying days of the week and at varying times.
- The drills shall be documented in QUEST The ERP shall be tested prior to start up of operation involving handling, analysis or storage of any samples containing $H_2S$ and be documented in QUEST.

**Neighboring Facilities**

Adequate warning systems and escape routes for lab staff and those working within the same area and sharing same entrances and exits should be placed in proper places.

All facilities should have at least two options of escape and at same time facilitate escape of others in same building; these procedures should be documented in laboratory and in Base Emergency Response Plans.

The Emergency Response Plans must be communicated to and drilled with personnel from neighboring facilities who make be affected by any $H_2S$ related emergency situation.

## *E.4.4.6* Review

Line management are required to review the location Hazard Analysis and Risk Control measures on a regular basis, to confirm there have been no significant changes. When changes in any activities occur that may change the associated risk, the hazard analysis shall be repeated as per the SLB-QHSE-S020 HARC Standard.

### E.4.5 Material and Equipment

Reservoir Sampling and Analysis equipment used for operations encountering any $H_2S$ must meet all requirements of NACE MR 0175, $H_2S$ Standard SLB-QHSE-01 and the Testing Pressure Operations Manual.

### E.4.6 Environment

$H_2S$ toxicity (the human health risk) and the potential for material damage due to the corrosive properties of aqueous solutions of $H_2S$ (and similarly $SO_2$) in contact with steel products dictate a need for stringent control of release into the environment.

In consideration of the above all reasonable efforts shall be made to minimize planned and/or contingent release of $H_2S$ (and $SO_2$) into the environment. Where such release or potential release e.g. from release through laboratory exhaust and ventilation system, sample blow down etc. is necessary the action shall be designed to reduce the potential risk to health, safety and the environment to levels that are as low as is reasonably practicable. Such tools as are known to be available e.g. dispersion models, design software’s etc. shall be employed to further the objectives stated herein.

### E.4.7 Audits

Regular audits against this standard are to be performed at all RSA locations at a minimum frequency of once per year and all Remidial Work Plans (RWP) are to be documented in QUEST.

Audits shall be conducted as required to applicable local, state and national regulations as applicable and all Remidial Worlk Plans (RWP) to be documented in QUEST.

## E.5 References

### E.5.1 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

- Hazard Analysis and Risk Control Standard SLB-QHSE-S020.
- NACE MR0175 Sulfide Stress Cracking Resistant Metallic materials for Oilfield Equipment.
- American Standards:
  - ANSI Z88.2 - 1992 Standard for Respiratory Protection.
  - US Code of Federal Regulations 29 CFR Subpart I: Personal Protective Equipment.
  - 29 CFR 1910.134: Respiratory Protection.
  - 42 CFR 84 Approval of Respiratory Protective Devices.
  - American National Institute for Occupational Safety and Health (NIOSH).
  - ANSI / Compressed Gas Association, G-7.1, specification for air.
- European Standards:
  - EN 136 through EN 149: Standards for Respiratory Protective devices.
  - EN 269, 270, 271: Standards for Hood-type SABA.
  - EN 400: Closed Circuit BA.
- Air Quality Standards:
  - All applicable Local, State and International Air Quality Regulations.
- Schlumberger, International and National Dangerous Goods Shipping Standards:
  - Testing Services Sample Management Standard.
  - Transportation of Dangerous Goods by Air, Sea, Road and Rail (OP 241).
  - International Air Transport Association (IATA) Dangerous Goods Regulations.
  - International Marine Dangerous Goods (IMDG) Code.
  - European Agreement concerning the International Carriage of Dangerous Goods by Road (ADR).
  - United States Code of Federal Regulations, Title 49, Transportation Parts 100 – 199 (e-CFR 49).
  - Transport Canada Regulations.

## E.5.2 Informative References

- $H_2S$ Level 1 Training

- $H_2S$ Level 2 Training

# E.6 $H_2S$ Characteristics and Units of Measurement

## E.6.1 $H_2S$ Characteristics

The Molecular Weight of $H_2S$ is 34.08. The boiling point of $H_2S$ is minus 62 degC (minus 79 degF) and its melting point minus 116 degC (minus 177 degF).
In concentrations above 20 ppm $H_2S$ produces irritation to eyes, throat and respiratory system.

In concentrations above 100 ppm it is immediately dangerous to health with a lethal air concentration for humans of 600 ppm for 30 minutes.

With concentrations above 1000 ppm one breath is instantly disabling via diaphragm paralysis and fatal without immediate resuscitation.

$H_2S$ forms an explosive mixture with a concentration between 4.3 and 45.5 percent by volume.

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**Note**
This is a very wide range as compared with butane, propane etc.

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Auto ignition occurs at 260 degC (500 degF). $H_2S$ is corrosive to all electrochemical series metals and in the absence of oxygen (e.g. in separator vessels, tubulars) can react and form pyrophoric deposits prone to spontaneous combustion on exposure to atmosphere. $H_2S$ burns with a blue flame and produces Sulfur Dioxide ($SO_2$).

## E.6.2 $H_2S$ Unit of Measurement

In dealing with $H_2S$ several different units may be in use for measuring its concentration.

The Schlumberger Standard unit is ppm - Parts Per Million for concentration in gas.

Other industry recognized units and conversions include:

- 1% = 10,000 ppm
- 0.65 Grains per SCF (Standard Cubic Foot) = 10 ppm

- 0.001 MOL% (and VOL%) = 10 ppm
- 15 mg/Cu.M. (1 mg/$m^3$ = 0.717 ppm @ 25°C) = 10 ppm
- 10 ppm is a very small concentration; it is comparable to 10 kg in 1000 tonnes.

# E.7 Appendix E Revision History

For more details see Appendix F.

**Warning**

| | |
|---|---|
| Potential Severity: | Serious |
| Potential Loss: | Security |
| Hazard Category: | Human |

The controlled source document of this manual is stored in the InTouch Content ID 3045666. Any paper version of this standard is uncontrolled and should be compared with the source document at time of use to ensure it is up to date.

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# Revision Release Notes

# F Revision Release Notes

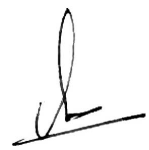
This appendix contains the Revision Record Summary Table for the Testing Services POM and the Revision Release Notes for each Pressure Operations Manual Revision. Sub-paragraphs within the Revision Release Notes contain a brief of the release notes for each section and appendices. Within these sub-paragraphs, release notes for each section or appendices are the details of the changes to each section or appendices.

**Table F-1: Testing Services Pressure Operations Manual Revision Record Summary Table**

| POM Rev No. | Effective Date | Sections Affected, Remarks | Prepared By (name) | Reviewed By (name) | Approved By (name) |
|---|---|---|---|---|---|
| 1.0 | December 18, 2000 | 1st major release | Jean Luc Monnac, WCP-T Operations Support Mgr | | Mark Riding, Testing General Mgr |
| 2.0 | January 30, 2001 | 2nd major release | Jean Luc Monnac, WCP-T Operations Support Mgr | | Mark Riding, Testing General Mgr |
| 3.0 | April 2, 2001 | 3rd major revision | Jean Luc Monnac, WCP-T Operations Support Mgr | | Mark Riding, Testing General Mgr |
| 3.1 | October 12, 2001 | Edits to Section 1 | Jean Luc Monnac, WCP-T Operations Support Mgr | | Mark Riding, Testing General Mgr |
| 4.0 | June 28, 2003 | 4th major revision | Adriano Bastos, WCP-T Operations Support Mgr | | Mark Riding, Testing General Mgr |
| 5.0 | March 8, 2005 | Temporary release of Sec 6 | | | |

| POM Rev No. | Effective Date | Sections Affected, Remarks | Prepared By (name) | Reviewed By (name) | Approved By (name) |
|---|---|---|---|---|---|
| 5.1 | May 17, 2005 | 5th major release. Major Revisions to: Sections 6, 9 and Appendix A. Minor revisions to: Sections 1, 2, 3, 4, 5, 6, 7, 8, 9 and Appendices A, B, C, D, E, F, G | Keith Barnard, InTouch Engineer | Charles Van Petegem, Testing Operations Support Mgr; Les Swan, WCP Operations Support Manager - Core Completions /RMC;Gene Barnett, AL Operations Support Mgr | Mike Jardon, WCP QHSE and Operations Support Mgr |
| 5.2 | January 31, 2006 | 6th major release. Major Revisions to: Sections 3,4,5,8,9 and Appendices D, F. Minor revisions to: Sections 1, 2, 3, 4, 5, 6, 7, 8, 9 and Appendices B, C, E, G. | Keith Barnard, InTouch Engineer | Charles Van Petegem,WCP Operations Support Manager | Mike Jardon, WCP QHSE and Operations Support Mgr |
| 6.0 | January 31, 2008 | 7th release.<br>Major Revisions to: Sections 3,5,6,9 & Appendix A, B & C.<br>Minor revisions to: Sections 1, 2, 4, 7, 8 & Appendices D, E, F & G | John Hartleroad Marc Garriga Guillaume Prat TS InTouch Engineers<br>Jonathan Richards, Oilphase Operations Support Mgr<br>Ian Graham TS SRPC Rapid Response / Sustaining Mgr | | Enrico Barbaglia, TS QHSE and Operations Support Mgr |

| POM Rev No. | Effective Date | Sections Affected, Remarks | Prepared By (name) | Reviewed By (name) | Approved By (name) |
|---|---|---|---|---|---|
| 7.0 | January 31, 2011 | 8th release.<br>Major Revisions to: Sections 1,2,3,4,5,6,7,8 & Appendix A, B, D, E, F. | Jean-Noel Mauze<br>Christopher Daniel | | |
| 7.1 | February, 2011 | 9th release<br>Minor revisions to:<br>Sections: 1, 2, 3, 4, 5, 6 Appendix A, B<br>Major revisions to: Appendix: B, D | Jean-Noel Mauze<br>Christopher Daniel | | |
| 8.0 | February, 2012 | Major revisions. Version 8.0 of the Pressure Operations Manual represents an important rework of the standard with significant changes or additions in most sections. | Jean-Noel Mauze<br>Christopher Daniel | | |
| 8.1 | December, 2012 | | Jean-Noel Mauze | TS SRPC ITE | JL Monnac |
| Current revision approved by: | | | Signed: | | |

| POM Rev No. | Effective Date | Sections Affected, Remarks | Prepared By (name) | Reviewed By (name) | Approved By (name) |
|---|---|---|---|---|---|
| Jean-Luc Monnac<br>Testing Services Operations Support Manager | | |  | | |
| 8.2 | January, 2014 | | Jean-Noel Mauze, Stephane Moreau | TS SRPC ITE | JL Monnac |
| Jean-Luc Monnac<br>Testing Services Operations Support Manager | | |  | | |

## F.1 Revision 1.0, December 18, 2000, Release Notes

First major release of the TS Testing Pressure Standard.

## F.2 Revision 2.0, January 30, 2001, Release Notes

Second major release of the TS Testing Pressure Standard.

## F.3 Revision 3.0, April 2, 2001, Release Notes

Third major release of the TS Testing Pressure Standard.

## F.4 Revision 3.1, October 12, 2001, Release Notes

Grammatical edits to Section 1, Revision 3.0.

# F.5 Revision 4.0, June 28, 2003, Release Notes

This standard replaced the Pressure Operating Manual Revision 3.0 dated Jan 2001.

This standard addresses the testing sub segment activities only in addition to the OFS-QHSE Pressure Standard S014.

The wellhead equipment section of the former pressure operating manual has been changed to an additional standard that will be published by the RE-WL/CH and RD-WI segments.

# F.6 Revision 5.1, May 17, 2005, Release Notes

Revision 5.1 replaces the Pressure Operating Manual Revision 4.0 dated June 28, 2003.

In summary, Sections 6, and 9 contain several major revisions. Sections 6, 9 and Appendix A are documented as being shared between WCP and Wireline. The other sections and appendices are WCP specific. These remaining sections or appendices contain limited major revisions and/or only minor revisions.

The details of the changes of each section or appendices are posted at the end of each section or appendices and within the following Sections (E.2.6.1 through E2.6.16).

## F.6.1 Section 1 Amendments, Revision 5.1, May 17, 2005

Major revisions: none.

Minor revisions include:

- Document formats, legal/copyright information.
- Addition of sub-sections for revision notes.
- Enhanced Section 1 Revision History Table 1.3.
- The Hyperlink Reference to the control document changed to the InTouch Knowledge base Content ID 3045666.

## F.6.2 Section 2 Amendments, Revision 5.1, May 17, 2005

Major revisions:

- Section 2.4.5: Equipment Sales. Pressure Equipment must not be sold without prior approval of WCP Operations Support.

Minor revisions include:
- Document formats, legal/copyright information,
- Addition of sub-sections for revision notes,
- Added hyperlink to InTouchSupport.
- Enhanced Section 2 Revision History Table 2.4.
- The Hyperlink Reference to the control document changed to the InTouch Knowledge base Content ID 3045666.

## F.6.3 Section 3 Amendments, Revision 5.1, May 17, 2005

Major revisions: none.

Minor revisions include:
- Document formats, legal/copyright information,
- Edited into 3.4.8.2, B) the 1/2 in. NPT discussion from 4.4.1.1.
- Addition of sub-sections for revision notes,
- Enhanced Section 3 Revision History Table 3.8.
- The Hyperlink Reference to the control document changed to the InTouch Knowledge base Content ID 3045666.

## F.6.4 Section 4 Amendments, Revision 5.1, May 17, 2005

Major revisions: none.

Minor revisions include:
- Document formats, legal/copyright information,
- Addition of sub-sections for revision notes,
- Enhanced Section 4 Revision History Table 4.4.
- Added hyperlink: www.InTouchSupport.com.
- The Hyperlink Reference to the control document changed to the InTouch Knowledge base Content ID 3045666.

## F.6.5 Section 5 Amendments, Revision 5.1, May 17, 2005

Major revisions: none.

Minor revisions include:
- Document formats, legal/copyright information,
- Edited into 5.3.4 the 1/2 in. NPT discussion from 4.4.1.1.
- Addition of sub-sections for revision notes,
- Enhanced Section 5 Revision History Table 5.2.
- Added hyperlink:www.InTouchSupport.com.
- The Hyperlink Reference to the control document changed to the InTouch Knowledge base Content ID 3045666.

## F.6.6 Section 6 Amendments, Revision 5.1, May 17, 2005

Revision 5.1 of Section 6, WCP Pressure Operations Manual – Sampling and Analysis Pressure Equipment replaces Revision 4.0 dated June 28, 2003.

In summary, this revision includes a number of additions, changes and clarifications to Section 6 as outlined below. The major changes are the addition of new content specific to WCP Oilphase-DBR fluids analysis equipment and a review of material specific to Wireline sample chambers.

The following is a list of key changes in order of appearance:

**6.0 Sampling and Analysis Pressure Equipment**

Equipment categories expanded to include:
- Category 0 - downhole sampling equipment which falls into Category 1 when brought to surface containing pressurized fluids
- Category 3.2 - DST Equipment (e.g., SCAR)

**6.1.1 Test Pressure**

Statements added:

Consult the latest RITE File Codes and Operating/Maintenance Manuals/Procedures within InTouch prior to commencing any pressure testing of sampling and analysis equipment.

**Note**
Each transportation certifying authority (US-DOT, Transport Canada etc.) has different certification requirements which must be strictly adhered to.

Table 6.1 and 6.2 updated to include examples of test pressure for WCP Oilphase-DBR sampling tools and receptacles respectively.

Table 6.3 created to detail test pressures of specific Wireline Sample Chambers.

#### 6.1.1.1 Test Pressure of Laboratory Fluid Analysis Equipment

Addition of paragraph relating to test pressures of current and legacy Laboratory Fluids Analysis equipment as manufactured by Oilphase-DBR in Edmonton, Canada (Schlumberger Reservoir Fluids Centre Edmonton, SRFCE).

### 6.1.2 Service Category

Addition of paragraph relating to $H_2S$ Service as applicable to current and legacy Laboratory Fluids Analysis equipment as manufactured by Oilphase-DBR in Edmonton, Canada (SRFC-E).

### 6.2.2 General WCP Oilphase-DBR Specifications

Addition of specification F. High Pressure Laboratory Fluid Analysis Equipment and PVT Cells (Category 1.1).

#### 6.2.2.1 General Surface Sampling Standards and Specifications

Addition of section relating to equipment designed to handle pressure and flow (e.g., Wellsite Sampling Module, Surface Sampling Manifolds).

#### 6.2.2.2 General Laboratory Fluids Analysis Standards and Specifications

Addition of section relating to pressure equipment manufactured by WCP Oilphase-DBR Product Centre, Edmonton (SRFC-E), includes applicable standards and design codes and key market regulatory requirements.

Addition of section relating to the use of 15 k psi NPT fittings in Laboratory Fluids Analysis Equipment.

### 6.3.2 Selection of Equipment Working Pressure

*Clarification and revision of sections relating to WCP equipment*

- WCP Downhole Sampling Tools
- WCP Surface Sampling Equipment
- WCP Sample Receptacles
- WCP MRSS Sample Bottles (MSB)
- WCP PVT Cells

*Clarification of Sections relating to Wireline Equipment*

- Wireline Sample Chambers

### 6.4 Wireline Sample Chamber General Rules

Addition of statement “Qualified Schlumberger personnel or Schlumberger approved third party transfer company personnel will operate Wireline sample chambers during high pressure transfer operations after recovery to the surface”

#### 6.4.1 Pressure Rating

*Table 6.5 Wireline Sample Chamber Ratings updated*

Extensive testing has shown that the Ti Beta-C material used in the MDT $H_2S$ Sample Chambers cannot be used to the original pressure rating. Table 6.5 shows the new rating of 15,000 psi working pressure and 18,000 psi test pressure for the Ti Beta-C chambers. Modification Recaps have been issued for each of the chambers detailing a mandatory replacement of the Ti Beta-C cylinder over a three-year period. The File Code of the chamber will change when the cylinder is replaced with the new Inconel cylinder. The new file codes are MRSC- BC,GB,PB,DC,JB, which have the pressure rating of the original chambers. Refer to InTouch Content 3892964 for more details.

### 6.5 Transportation of Pressurized Sample Receptacles

Section updated with links to:

- WCP Oilphase-DBR procedure OP 241 - Transportation of Dangerous Goods by Air, Sea and Road
- WCP Oilphase-DBR Dangerous Goods Guidelines

#### 6.5.4 US and Canada Transport Approvals

Section updated with link to Sample Bottle Shipping Matrix.

Table 6.6 Transport Approvals for Wireline Sample Receptacles updated to only include MPSR, 1 gallon MRSC and 2.75 gallon MRSC.

#### 6.6.5 Heating of Sampling Equipment and Sample Receptacles (Sample Conditioning)

Section expanded regarding heating of reservoir samples within WCP Oilphase-DBR Fluids Analysis Laboratories.

Table 6.7 updated to include Asset Code column. MSB added to table and applicable Wireline asset codes updated (MRSC-DC, JB, GB, PB).

### 6.6.6 Transfer and Filling of PVT Cells

New section added relating to filling of PVT cells.

### 6.7 Sampling and Analysis Manifolds, Hoses, Liners, Fittings and Connectors

Note added regarding purchasing of pressure fittings etc. from OneCAT or Schlumberger approved vendor only.

### 6.7.1 General Safety Rules

Statement added, "When taking Atmospheric (Dead) Oil Samples earthing cable with clips MUST be fitted between the sampling hose end outlet and the sample can and also from the sampling can to the separator earth point. These earthing cables MUST be fitted prior to and during sampling"

### 6.8 WCP Fluid Sampling and Analysis Equipment Pressure Testing

Statement added "Laboratory Fluid Analysis Equipment must be pressure tested after being re-assembled and prior to charging samples into the vessel.

### 6.8.1 Basic Wellsite and Laboratory Pressure Test Policy

Sections added:

k) Detailed procedures for wellsite pressure testing of sampling and analysis equipment are to be found in WCP Oilphase-DBR Operating Procedures on InTouch.

l) Wireline Sample Chambers are not required to have a wellsite pressure test. The chambers must have a low pressure test, 100 psi minimum, to test the integrity of seals following any chamber service.

### 6.9 Special Operations and Environmental Limits

Additional Statement "In summary it is important that advise is sought via InTouch where aggressive well fluids have to be sampled or aggressive well conditions are encountered so that materials and sealing systems can be optimized.

See InTouch Content ID 3993830 for Environmental Limits for Oilphase Sampling Equipment."

### 6.9.1 $H_2S$ Operations

Sections added:

e) Repairs and modifications to $H_2S$-rated equipment can only be carried out in qualified shops, approved by a Schlumberger WCP Technology Center. Welding must conform to NACE rules.

f) Samples where hydrogen sulphide is present at a level of greater than 0.5 psi partial pressure AND where free water is present at a pH of less than 4.5 may not be **transferred or shipped** in sample bottles of UNS S17400 stainless steel construction (AA, EA, IA, MA, QA, VA oil sample bottles). N.B. Partial Pressure = (Mol%H2S/100) × Pressure.

g) Operating limits of WCP Oilphase-DBR downhole sampling tools in sour environments are limited as below in table 6.10 to meet NACE MR-0175-200 section 10.7.4

**Table F-2: Table 6.9 Operating Limits of Downhole Sampling Tools in Sour Environments**

| Description | Limit in Non-sour Environment | Limit in Sour Environment |
|---|---|---|
| Single-Phase Reservoir Sampler (SRS) | 15,000 psi | 13,800 psi |
| Slimline Single-Phase Sampler (SLS) | 15,000 psi | 15,000 psi |

h) Prior to the venting or bleeding down of any sample(s) form any sample receptacle, the $H_2S$ content of the sample must be determined from the sample datasheet, welltest report, etc. Should $H_2S$ be expected, the appropriate risk prevention and mitigation measures shall be taken prior to venting the sample.

i) Laboratory experiments on samples containing $H_2S$ shall be performed in a designated and isolated $H_2S$ area.

j) $H_2S$ rated elastomers shall be installed where necessary.

k) Locations shall have in place an approved Emergency Response Plan to deal with uncontrolled $H_2S$ releases.

l) Hazard Analysis and Risk Control Standard OFS-QHSE-S020 shall be complied to with regards to operations at the wellsite or laboratory involving the potential production of $H_2S$.

### 6.10 Asset Certification, Maintenance and Quality Control

Additional Statement “RITE is the WCP business tool utilized to plan all maintenance, certification and modification recap implementation.”

Amended statement “Pressure equipment without a Quality File cannot qualify for field or laboratory use.”

### 6.10.2 Quality File

Statement added “The Wireline sample chamber quality files consist of the maintenance and testing records maintained in the RITE system, along with the material certification for the primary vessel body which can be found in the on line certification data base.”

### 6.10.3 Five Year Survey

Statement added, “Wireline chambers shall have a detailed inspection and pressure test every five years. The details for this test and inspection are found in content #4030749 in InTouchSupport.com.”

### Table 6.11 - Five Year Survey Requirements

Wireline Sample Chambers removed from table 6.10 (previously table 6.8)

Statement regarding Wireline Sample Chambers removed.

### 6.10.4 Routine Inspection and Annual Surveys

Statement added regarding Wireline sample chambers “Wireline Sample Chambers must have an annual visual inspection of all pressure containing parts, and an internal pressure test to working pressure. Refer to content #4030749 in InTouchSupport.com. Record the inspection and test results in the RITE System.”

### 6.10.6 Equipment Identification

Statement added, “For Wireline Sample Chambers, the information above will be required only on the sample cylinder. Where possible, individual components will be marked with a part number and PO number for material tracking.”

Statement added, “N.B. WCP Fluid Sampling and analysis equipment does not need to be color coded to per its assigned Working Pressure.”

### 6.11.1 Newly Purchased Equipment

Section updated to reflect use of:

- WebEPU for CAPEX planning. WCP Oilphase-DBR assets can be found under OPC in asset catalogue.
- OneCAT for supply of seals, pressure fittings and hoses etc.
- WCP Rapid Response (R 1/2 or R 3/4) for requests of purpose built systems to comply with special client requirements.

### 6.11.2 WCP Reception Control

New section added regarding reception control of new and loaned in equipment.

### 6.11.3 Rented Sampling Equipment (previously section 6.11.2)

New statements added:

- "Renting Sampling equipment such as sample bottles is strongly discouraged however they may be rented from a rental agency if the following policies are respected:"
- "An authorized rental agency representative shall sign the certificate(s)."
- "All rental equipment must have proven full traceability as per Schlumberger standards."

### 6.11.4 Client Supplied Sample Receptacles

New statements added:

- "Sample receptacles given by the client to Schlumberger WCP for use shall follow all identification, maintenance and qualification requirements as for Schlumberger-owned equipment. Any substandard equipment shall be replaced."
- "Clients shall remain responsible for equipment supplied occasionally to Schlumberger for operations in clients' wells and on clients' wellsite."

### 6.12 WCP Asset Management

New section added related to WCP asset management, certification and maintenance.

### 6.13 WCP Personnel Certification (previously Section 6.12)

Revised statement "All well-site sampling and PVT laboratory analysis operations shall be performed exclusively by pressure-qualified Field Specialists, Field Engineers and PVT Laboratory personnel who are POM pressure certified or are under direct supervision of an individual who is POM pressure certified.

In order to become POM pressure certified for Fluid Sampling and Analysis operations, an individual must complete and pass the online Basic Oilphase POM quiz and in addition prove hands on competence under direct supervision in the laboratory, workshop or at the wellsite on a minimum of two jobs. Only then may the individuals line manager deemed an individual pressure certified and issue the certification.

### 6.14 Revision Release Notes (new section)

Section 6, Revision 5.1 release notes added.

Section 6 to be shared between **WCP** and **W**ireline from this revision forward.

Other miscellaneous minor revisions include:

- Legal/copyright information,
- Document formats,
- Addition of sub-paragraphs for revision notes,
- Enhanced Section 6 Revision History Table 6.14.

The Hyperlink Reference to the control document changed to the InTouch Knowledge base Content ID 3045666.

## F.6.7 Section 7 Amendments, Revision 5.1, May 17, 2005

Major revisions: none.

Minor revisions include:

- Document formats, legal/copyright information,
- Addition of sub-sections for revision notes,
- Enhanced Section 7 Revision History Table 7.1.
- The Hyperlink Reference to the control document changed to the InTouch Knowledge base Content ID 3045666.

## F.6.8 Section 8 Amendments, Revision 5.1, May 17, 2005

Major revisions: none.

Minor revisions include:

- Document formats, legal/copyright information,
- Addition of sub-sections for revision notes,
- Enhanced Section 8 Revision History Table 8.1.
- The Hyperlink Reference to the control document changed to the InTouch Knowledge base Content ID 3045666.

## F.6.9 Section 9 Amendments, Revision 5.1, May 17, 2005

**Section 9.1**

Changed to reflect OFS standard and appendix changes.

**Table 9.1**

API 6A minimal WP rating of 2000 psi has been introduced to address specific markets.

All WHE with WP up to 5000 psi will sustain WP/TP ratio of 1:2.

**Section 9.1.4**

Added the temperature limit values in deg C.

**Section 9.1.5**

The use of one single threaded crossover made-up on the well site has been re-introduced, due to the number of operating conditions where there is no alternative to it. The same rules that were applied when submitting an exemption are maintained. Basically the only change is the fact that an exemption is not required. There is a time limitation for the use of such crossover, and a more stringent inspection rule.

**Table 9.2.1**

Well Killing facilities to be on wellsite during operations, has been clearly specified.

The explanation of the phrase "client fully responsible for well control?" has been addressed in a specific content.

**Table 9.4**

Comments to the table have been modified in order to remove any possible contradiction with the table itself.

**Section 9.3.1.3**

For applications up to 5000 psi WP, with ID above 4.5 in. where a high torque has to be applied to energize the metal-metal seal, a threaded single O-ring connection can be used between the quick union and the riser tube: self explanatory.

**Section 9.3.1.7**

It has been specified that up to 5000 psi WP the use of a plug valve is allowed as a lateral isolation valve.

**Figure 9.1**

This figure has been modified to reflect the recommended rig-up: PIS above the BOP.

**Section 9.3.2.7**

As per 9.3.1.3

**Section 9.3.2.12**

As per 9.3.1.7

**Figure 9.2**

As per Figure 9.1

**Section 9.3.5**

The rating of WP and BP for flexible hoses has been reworded for the sake of clarity.

**Section 9.5.1**

Has been amended in order to reflect the change in section 9.1.5.1.

**Section 9.5.2.2**

3$^{rd}$ paragraph: self-explanatory policy reinforcement has been added.

**Section 9.6.1**

Paragraph b) c) and e) modified following various incidents reported in content 3993024

Maximum rates and pressures for test pumps have been specified.

The use of an equalization hose has been set to "recommended" to face the fact that there is often no alternative to opening the swab valve.

**Section 9.6.3**

This section has been thoroughly reviewed.

Reinforcement of Schlumberger policy not to pressure test WHE with loaded gun systems inside risers has been re-stated.

Allowed procedures for equalizing pressure from below to above swab valve of Xmas trees have been addressed.

**Section 9.7.2**

The word "workover" has been removed in the second paragraph: the concern is about operations with cranes and masts.

**Section 9.8.4 and 9.8.5**

Special instructions for Hydrolex Slimline threads have been introduced.

**Section 9.8.7**

Typo about appendix "G" has been corrected to "H".

The fact that stainless steel tubes used for LW WHE can remain unpainted has been specified.

**Section 9.10**

Guidelines for approval of existing equipment are now obsolete.

**Section 9.11**

Specific reference to the section 8 has replaced previous wording, which was contradictory with what stated in Section 8.

## F.6.10 Appendix A Amendments, Revision 5.1, May 17, 2005

Major Revisions:

- Appendix A to be shared between **WCP** and **Wireline** from this revision forward. No other major changes incorporated in Appendix A, Revision 5.1, May 17, 2005.
- Minor revisions include:
  - Document formats, legal/copyright information,
  - Addition of sub-sections for revision notes,
  - Enhanced Appendix A Revision History Table A.2,
  - The Hyperlink Reference to the control document changed to the InTouch Knowledge base Content ID 3045666.

## F.6.11 Appendix B Amendments, Revision 5.1, May 17, 2005

Major revisions:

- Update Table B-2, "Grayloc" Clamp Connector Pipework as per request from SRPC.

Minor revisions include:
- Document formats, legal/copyright information,
- Addition of sub-sections for revision notes,
- Enhanced Appendix B Revision History Table B.7.1,
- The Hyperlink Reference to the control document changed to the InTouch Knowledge base Content ID 3045666.

## F.6.12 Appendix C Amendments, Revision 5.1, May 17, 2005

Major revisions:
- Addition of Section C.2 and C2.1 clarifying the Regional Manufacturing Process based on input from Regional Manufacturing.

Minor revisions include:
- Document formats, legal/copyright information,
- Addition of sub-sections for revision notes,
- Enhanced Appendix C Revision History Table C.5.1,
- The Hyperlink Reference to the control document changed to the InTouch Knowledge base Content ID 3045666.

## F.6.13 Appendix D Amendments, Revision 5.1, May 17, 2005

Major revisions:
- Corrected table reference in D.3.2: changed from Table 4.3 to refer to Table 4.2.
- Remove from D 3.2, "API RP 14E 91: refer to Paragraph 1.7 e", re: Paragraph 1.7e does not exist in the WCP POM Rev 4.0 (previous revision).

Minor revisions include:
- Document formats, legal/copyright information,
- Addition of sub-sections for revision notes,
- Enhanced Appendix D Revision History Table D.5.1,
- The Hyperlink Reference to the control document changed to the InTouch Knowledge base Content ID 3045666.

## F.6.14 Appendix E Amendments, Revision 5.1, May 17, 2005

Major revision:

- Addition of Table E.1 - WCP Pressure Operations Manual Revision Record Summary Table,
- Addition of sub-paragraphs for revision notes, including reorganization of contents as shown herein,
- Addition of detailed revision notes for each POM Section and/or Appendices,
- Addition of Appendix E Revision History Table E.3.1.

Minor revisions include:

- Document formats, legal/copyright information,
- The Hyperlink Reference to the control document changed to the InTouch Knowledge base Content ID 3045666.

## F.6.15 Appendix F Amendments, Revision 5.1, May 17, 2005

Major revisions: none

Minor revisions include:

- Document formats, legal/copyright information,
- Addition of sub-sections for revision notes,
- Enhanced Appendix F Revision History Table F.2.9,
- The Hyperlink Reference to the control document changed to the InTouch Knowledge base Content ID 3045666.

## F.6.16 Appendix G Amendments, Revision 5.1, May 17, 2005

Major Revisions: none.

Minor revisions include:

- Miscellaneous grammatical edits,
- Increase “Cell” options,
- Document Version upgrade from 3.0 to 3.1.

# F.7 Revision 5.2, January 31, 2006, Release Notes

Revision 5.2 of Appendix E, WCP Pressure Operations Manual dated January 31, 2006 - Revision Record replaces Revision 5.1 dated May 17, 2005.

The details of the changes of each Section or Appendices are posted at the end of each Section or Appendices and within the following sub-paragraphs E.2.7.1 through E2.7.16.

## F.7.1 Section 1 Amendments, Revision 5.2, January 31, 2006

Major revisions: none.

Minor revisions: Wording and document formats.

## F.7.2 Section 2 Amendments, Revision 5.2, January 31, 2006

Major revisions: none.

Minor revisions:

Section 2.4.1: Added, “Surface Equipment crossovers shall carry the whole body color blue with the proper color band and overall Working Pressure rating of the lowest rated connection or other part. For example, a 2 in. 1502 by 2 in. 2202 surface piping crossover will have the Schlumberger assigned WP rating of the lesser 2 in. 1502 connection of 10,000 psi. The whole body color will be blue and it will have a black band.”

## F.7.3 Section 3 Amendments, Revision 5.2, January 31, 2006.

Major revisions:

**3.1.1 Test Pressure**

Table 3.1 - Test pressure for surface testing equipment. API 6A/ISO 10423 was updated to the 19th Edition effective February 1, 2005. Within this 19th Edition the Test Pressure for 5000 psi Working Pressure equipment was reduced from 2 times to 1.5 times the Working Pressure. Changed the 10,000 psi TP requirement to 7500 psi TP.

Added the caution statement: “Do not exceed the manufactures Test Pressure rating of any component(s) of any Surface equipment assemblies” and the ensuing discussion.

Added a discussion with an example to support the above caution statement.

### 3.1.2 Service Category

Clarified the definition of Service Category by giving reference to Section 1, paragraph 1.7.

#### 3.1.2.1 Surface Well testing Equipment

Clarified Maximum operation temp, minimum design temp, Service Type and PSL.

### 3.2 Standards and Specifications

Replaced “Pt. 6 Drill (N)” with the new DNV “Offshore Standard DNV-OS-E101, Drilling Plant”.

### 3.2.1 General Standards

Added bullet “API RP 520 and API RP 521 Pressure Relief Systems”.3.2.2 General WCP Specifications

Removed existing discussion and added “Minimum specifications shall be as follows:

- Standard Service:
  - Design temperature: -20°F to 250°F, API 6A\ISO 10423 temperature Class P + U
  - API 6A Product Specification Levels: PSL2 up to 10,000 psi, PSL1 up to 5000 psi.
  - API 6A Material Class AA
- $H_2S$ Service:
  - NACE MR0175
  - Design temperature: -20°F to 250°F, API 6A\ISO 10423 temperature Class P + U

- API 6A Product Specification Levels
- PSL2 for 5000 psi WP, PSL3 to PSL4 for 10,000 psi WP and PSL3 to PSL4 for 15,000 psi WP.
- API 6A Material Class DD

- Hostile Service: ($H_2S$ Service + high temperature/high pressure):
  - NACE MR 0175
  - Design temperature: -20°F to 350°F, API 6A\ISO 10423 temperature Class P + X
  - API 6A Product Specification Levels: PSL2 for 5000 psi WP, PSL3 for 10,000 and 15,000 psi WP and PSL4 for 20,000 psi WP.
  - API 6A Material Class DD

**Note**

As defined in NACE, conformity to NACE Material Requirements applies to all components of equipment exposed to sour environments.

Equipment sold to Schlumberger locations operating within the European Community shall comply with the latest directives providing for CE marking and be in compliance with ATEX latest directive whenever required.”

### 3.4.8.1 Pipework Sizing

Added - it is recommended for high flowrate jobs (greater than 30MM scf or 8000 BPD) to check critical piping thicknesses before, during and after each job and to use targeted flanges or cushion elbows.

3.6.1 $H_2S$ Operations

Added 2 bullets:

- If $H_2S$ is present the use of produced gas to supply any equipment (including instrumentation) is forbidden.
- Windsocks must be strategically placed to allow viewing from operating areas.

### 3.7.2 Regular Inspection and Annual Surveys

Changed name from Routine to Regular to follow established RITE convention.

Changed this statement to read as a must statement: “The Annual Survey must be recorded in the Quality File, following the rules set forth in Section 2, paragraph 2.6, and a band or plate giving the date of last test must be attached to each individual piece of equipment.” This statement is coordinated with Section

B1.3, Identification of Testing Pipework: Replaced “Room is left on he band for additional markings done after each survey” with “Last test date and type, e.g., Last Test 1-31-06 WP.

**3.9.1 Surface testing Crew**

Added the following from Section 8, “A crew operating surface testing equipment is qualified if the crew has a valid pressure certification as prescribed in Section 8 of the WCP Pressure Operations Manual

Surface testing pressure certifications are:

- “Pressure Level 2 Surface Welltest Certification” - Pressure certification for SWT (equipment operation) for maximum allowable equipment working pressure up to and equal 10,000 psi and/or maximum flowrates up to 30 MMSCF/D gas and/or 8000 bpd liquid.
- “Pressure Level 3 Surface Welltest Certification” - Pressure Certification for SWT (equipment, design and operation) for working pressure above 10,000 psi and/or flowrates above 30 MMSCF/D and/or 8000 bpd liquid. Replaces the “Advanced Surface Welltest” certificate.

**Minor revisions:**

Miscellaneous document formats, references and wording.

## F.7.4 Section 4 Amendments, Revision 5.2, January 31, 2006

Major revisions:

Changed Re-certification to Major Survey.

**Section 4.1: Overview**

- Added phrase, “It is recommended for the landing string (from the surface flowhead to the major string) to be analyzed as a system to identify the overall weak point and to confirm system compatibility with worst-case combinations of tensile and axial loading with respect to maximum potential pressures. At a minimum, it must be confirmed that the client has conducted this analysis.”
- Changed WP temperature range to 38°F to 325°F.

**Section 4.1.1: Test Pressure**

Table 4.1 - Maximum recommended Test Pressure for Subsea Safety Equipment - Removed “and Major Re-Certification”, added column - Major Survey. Added the sentence, “Pressure Testing at Major Re-Certification of Assets in accordance with original FAT” following the table.

Added, “maintenance guidelines for Subsea equipment follow the RITE methodology of FIT, TRIM, Q-CHECK, etc. Subsea assets and the associated maintenance must be tracked in RITE. Specific maintenance details are given in relevant Maintenance or Operations Manuals.”

Added, “the maximum Working Pressure (WP) rating of a system is defined by the lowest WP rating of any component within the system. For example, in the SenTREE 7 assembly it is common for a project specific component such as the latch mandrel to have a lower WP rating than some of the other components. In this case the maximum WP rating of the SenTREE 7 system assembly will be the same as the WP rating of the latch mandrel.”

**Section 4.2: Standards and Specifications**

Updated DNV rules for classifications of mobile offshore units from, “Part 6, Chapter 5, Drilling plant - (Drill) (N)” to “Offshore Standard DNV-OS-E101, Drilling Plant”.

**Section 4.3.2: Selection of Equipment**

Clarified the 2-barrier policy to include both the tubing and the annulus.

Added, “A job or project specific Hazard Analysis and Risk Control should be performed to identify and mitigate risks, particularly the risks associated with barriers for the annulus and the tubular wellbore.

Added paragraph, “In subsea wells, particularly deep water wells, consideration for hydrostatic collapse from riser fluid column must be considered. As a minimum, if no other data is available, worst case is to assume gas column in well bore and annulus fluid column in riser. Where applied pressure below a closed BOP ram occurs, the additional surface applied pressure shall also be taken into consideration.

**Section 4.4.1.1: Fittings**

Added clarifications for the limitation on the use of 1/2 in. NPT fittings, added examples.

Added fittings with the potential to be exposed to $H_2S$ must be compliant with NACE MR-0175.

Removed the sentence, “Above 5000 psi WP, NPT fittings shall be 1/2 in. nominal diameter or smaller” - leads to confusion.

**Section 4.4.1.2: Flexible Hoses**

Clarified that, “Re-swaging of hoses shall only be performed by trained personnel”.

Changed Design Safety Factor to 4 x WP up to 12,500 psi ratings and burst pressure = 3.5 WP for pressures above 12,500 psi.

**Section 4.4.1.3: Rigid Hydraulic Lines**

Changed paragraph to Include Inconel 625, Inconel 825 and Super Duplex 2507. Also added that all the materials listed are acceptable for welded end fittings.

**Section 4.5: Crossovers:**

Added to, “Refer to Appendix C, Local Manufacturing and Procurement for crossover procurement details”.

**Section 4.6.1: Basic Wellsite Pressure Test Rules**

Added to refer to Section 1.9 for guidelines for integrity testing with inert gas (nitrogen or helium).

Added HARC must be completed if integrity testing with diesel (requirement of an Exemption maintained).

**Section 4.8.3: Major Re-Certification**

- Changed title to “Five Year Major Survey”.
- Changed 1st paragraph to read - “A detailed survey and performance verification conducted by or under the control of a certification agency. All pressure containing subsea testing equipment shall undergo a major survey every five years. This includes, as a minimum, a visual inspection, nondestructive examination tests and body hydrostatic and functional pressure tests, witnessed and certified by a certification agency. Procedures for these tests are regulated by API 6A code and are detailed in GeMS document 100282338, which is included in the operations and maintenance manuals.”
- Deleted Table 4.3 Test Pressure for Subsea Safety Equipment

**Section 4.8.4.3: Annual Survey or Q-Check**

Organized bullets discussing inert gas integrity testing.

Removed “or Major Re-Certification” from Table 4.3 - Test Pressure for Subsea safety equipment.

Changed Maximum acceptable leakage with air pressure above 100 psi to 1.25 scf/min.

**Section 4.10: Crew Certification**

Added current updates from Section 8, “A wellsite crew shall be considered qualified if the supervisor and at least 50% of the other crew members hold a valid certification. On multidiscipline crews, at least one operating technician or engineer per discipline must be certified. Crew members not holding a valid certification must be qualified by having completed at a minimum Intermediate Level 1 training (i.e., certification may be pending satisfactory completion of the theoretical quiz, technical training, and practical jobs or tasks under supervision). Subsea pressure certification details are provided in Section 8 of this Pressure Operations Manual.”

**Minor revisions:**

Miscellaneous document formats, references and wording.

## F.7.5 Section 5 Amendments, Revision 5.2, January 31, 2006

**Major revisions:**

**Section 5.10, Crew Certifications:**

See Section 8, Personnel Qualification and Administration.

Removed references to Appendix F, Interim Guidelines. Appendix F is obsolete as of this publication, Revision 5.2.

**Minor revisions:**

Miscellaneous document formats, references and wording.

## F.7.6 Section 6 Amendments, Revision 5.2, January 31, 2006

**Major revisions:** none.

**Minor revisions:**

Miscellaneous document formats, references and wording.

**6.6.5 Heating of Sample Equipment and Sample Receptacles**

Changed from 60°C to 60°F in the following statement, “On completion of the heated transfer the sampling tool should be allowed to return to ambient temperature or less than 60°F before any further work is undertaken on the sampling tool”.

**6.13 Personnel Certification**

Removed WCP from the Section title heading.

Edited to read “pass the online the online Pressure Fluid Sampling and Analysis Operations quiz and in addition prove hands on competence under direct supervision in the laboratory, workshop or at the wellsite on a minimum number of jobs or tasks as per the Learning Management System (LMS) and/or Section 8, Personnel Qualification and Administration.”

## *F.7.7* Section 7 Amendments, Revision 5.2, January 31, 2006

**Major revisions:** none.

**Minor revisions**

Miscellaneous document formats, references and wording.

## *F.7.8* Section 8 Amendments, Revision 5.2, January 31, 2006

**Major revisions:**

**Section 8.0: Personnel Qualification and Administration**

Aligned Certifications and levels with the five training proficiency levels (0, 1, 2, 3, 4) of LMS as established by SLB-QHSE-S005.

Added definition of Level 2 and Level 3 training as per the five training proficiency levels in LMS as established by SLB-QHSE-S005.

- Advanced, systems implementing. Demonstrates a comprehensive understanding. Can operate independently without any significant errors.

- Expert, system managing. Demonstrates a mastery understanding. Can operate under all conditions and can supervise and train others at previous levels.

Added definition of a certification to include technical training course(s), on-line quizzes and that required number of jobs and required are defined in LMS.

**Section 8.1: Pressure Certification Procedures**

Defined the Learning Management System (LMS) as a training and career development tool used to track wellsite operating personnel's pressure certification.

Moved crew certification paragraph from Section 8.0 to this Section.

Added clarification of required training for the allowable 50% of crew members not holding a valid certification: "must have completed at minimum of Level 1 training".

**Section 8.1.1: Pressure Level 2 Certification**

Changed Certification names and levels to align with the five training proficiency levels in LMS as established by SLB-QHSE-S005.

Changed requirements from a certificate to a certification validated within LMS beginning January 2006, subject to Location Management approval.

**Section 8.1.2: Pressure Level 3 Certification**

Changed Certification names and levels to align with the five training proficiency levels in LMS as established by SLB-QHSE-S005.

Changed requirements for a certificate to a certification validated within LMS beginning January 2006, subject to Location Management approval.

**Section 8.1.3: Certification Validity**

Added, "Personnel holding a valid Pressure Level 2 Certification or Pressure Level 3 Certification for wellsite operations are automatically certified for shop pressure testing unless other shop charging or testing certifications are applicable (e.g., FIV)."

**Section 8.1.4: Re-Certification**

Clarified Re-certification requirements for wellsite personnel:o

- Pass the theoretical quiz for the appropriate discipline and certification level

- Perform a minimum of one job during the last 12 months. If not, the quiz is not sufficient and personnel must perform one job under supervision.

Work shop or base personnel to follow Section 8.1.8.

**Section 8.1.5: New Hired - Senior Field Personnel**

Moved this sub-section to go before Existing Field Personnel.

Removed the grandfather statement "Schlumberger operating personnel without a valid basic pressure certificate, but currently performing pressure operations, can obtain the certificate by following the same procedure as outlined in Section 8.1.2." This no longer applies because all personnel performing pressure operations were certified prior to December 31, 1999.

**Section 8.1.6: Existing Field Personnel**

Moved this sub-section to follow New Hired - Senior Field Personnel.

Clarified that for new mid-career hires the technical course training is not required for the Pressure Level 2 Certification pending discretion of Location management and successful completion of the quiz.

Clarified that new mid-career hires must follow Section 8.1.2 to obtain the Pressure Level 3 Certification.

**Section 8.1.7: Third Party Personnel**

Clarified that 3rd Party Personnel must have the applicable pressure certification by:

- Passing applicable theoretical on-line Certification quiz in LMS
- Demonstrate jobs and tasks proficiency in the form of a CV (Curriculum Vitae) with references for a minimum of 2 certification applicable jobs within the last 2 years. One of the jobs must have been completed within the last 12 months.

Clarified the legacy exception to the rule that 3rd party supplied personnel operating the equipment they supply is acceptable provided the agency (3rd party's employer and equipment supplier) certifies their proficiency in writing and provides references for a minimum of 2 certification applicable jobs within the last 2 years. One of the jobs must have been completed within the last 12 months.

Added any deviation requires a QUEST exemption as per OFS-QHSE-S010.

**Section 8.1.8: Pressure Certification Procedures - Work Shop or Base Personnel**

Changed from the requirement to maintain 2 levels of certifications, one for 10K psi and below and one for above 10K psi to a single certification for all shop pressure operations including existing field personnel, new hired senior field personnel and third party personnel.

New certification name, Pressure Level 2 Work Shop Certification.

Align with the five training proficiency levels in LMS as established by SLB-QHSE-S005 (previous names of Level 1 and Level 2 were conflicting with QHSE guidelines). Complies with Level 2 as per SLB-QHSE-S005.

Clarified that the Area, Region and/or GeoMarket have the responsibility to develop and implement the specific training program suitable for the Location.

Added personnel holding a valid Pressure Level 2 Work Shop Certification are not certified for wellsite operations.

Added Certification validity period maximum of 2 years and the re-certification requirements.

**Section 8.1.9: Pressure Certification Tables**

Added this sub-section to clarify organization of tables. Changed Tables numbering.

Created and inserted Table 8.1: QHSE Training Proficiency Guidelines.

Edited Tables to reflect current certifications and proficiency training in LMS.

**Section 8.2: Administration and Responsibilities**

Clarified that It is the responsibility of each certified personnel to keep his/her certification up to date and ensure its current status is maintained in LMS (if applicable) and their QHSE Passport.

Clarified that tracking of base personnel certifications are the responsibility of the Area, Region, GeoMarket and/or Location and currently not tracked in LMS.

**Section 8.3: Interim Guidelines and Implementation Timetable**

Added that applicable certifications must be recorded in LMS by June 30, 2006.

Added, “the previously identified as Basic or Advanced Certificate will be grandfathered in LMS to the applicable Certification starting January 2006.”

**Minor revisions**

Miscellaneous document formats, references and wording.

## *F.7.9* Section 9 Amendments, Revision 5.2, January 31, 2006

**9.1.1 Definitions**

Three new definitions have been added.

**Table 9.1**

The 2000 psi WP rating has been removed: no specific equipment with that rating will be used by Wireline.

**9.2.4 Surface Pressure Barriers**

Pressure barriers have been divided in 2 categories: Primary and Secondary.

**9.2.4.1 Required number of barriers**

A new flowchart has been made

**Table 9.2 (previously table 9-4)**

This table has been simplified and clarified

**9.2.4.2 Flowchart question "… Client fully responsible for well control?"**

This section corresponds to an InTouch content which was already existing in the data base.

**9.2.4.3 No $H_2S$ Operating Condition**

This section has been introduced in order to clarify the meaning of a phrase commonly used in the document.

**9.3.2.3 Flow Tubes with Grease Injection**

Clarification has been introduced in compliance to the newly introduced definition of "surface controlled well head pressure" operating conditions.

**9.3.2.9 BOP - Blow Out Preventer**

Clarification has been introduced about the use of "shear and seal" rams.

**9.3.2.13 Cable Cutter**

New section, relevant to the introduction of a new tool.

### 9.4.1 Electrical and Stranded Line Work

Clarification has been added to explain the need for 2 separate lifting point on a WHE rig-up.

### 9.4.2 Pressurized Sheave Wheel

The hoist supporting the PSW must be compliant with OFS-QHSE-STD-13.

Clarification has been added to differentiate Elmar Pressurized Sheave Wheels from Hydrolex obsolete design.

### 9.5 Connection to Customer Equipment

The obligation for not using Weco connections to attach WHE to the Xmas tree has been formalized and explained.

### 9.5.2 Connection to BOP Stack

The importance of keeping down hole the tool string, any time a well surges, has been formalized.

### 9.6.1 Basic Well site Pressure Test Rules

Rule in f) has been modified. Requirements for a liquid to be used for pressure testing have been clarified. Wireline and WCP now align with WS requirement for 40% maximum quantity of Methanol to be used with water.

Rule in g) has been clarified, since well induced pressure testing can never reach the 1.2 times MPWHP requirement.

The cases where Schlumberger can agree with client's requirement not to pressure test have been detailed.

### 9.6.2 Wellsite Pressure Testing on Long-Duration Jobs or Multiple Wells

A minimal requirement for checking the mechanical connection between the various pieces of Well Head equipment has been introduced.

### 9.6.3 Wellsite Pressure Testing for Explosives Services (Perforating)

The fact that Chemical Cutters follow the same rules as gun systems, has been introduced and explained.

### 9.8.4 Routine Inspection and Pressure Testing

RITE definitions and relevant meaning for WHE operations, have been added. Grease injection modules specific maintenance programs are specified, with details in a relevant InTouch content.

## F.7.10 Appendix A Amendments, Revision 5.2, January 31, 2006

Major revisions: none.

Minor revisions: none.

## F.7.11 Appendix B Amendments, Revision 5.2, January 31, 2006

Major revisions: none.

Minor revisions:

**Section B.0 Scope:**

Added, Any deviation from the guidelines listed herein requires an exemption as per the Management of Change and Exemption Standard (OFS-QHSE-S010).

**Section B1.3, Identification of Testing Pipework:**

Replaced “Room is left on he band for additional markings done after each survey” with “Last test date and type (e.g., Last Test 1-31-06 WP)”. This is coordinated with Section 3.7.2 Regular Inspection and Annual Surveys.

**Section B.1.4.5 Figure 206 Pipework Limitations**

Corrected Typo “602” to read “206”.

Added, “See Section 3.4.8, Pipework, Definitions, Fittings: Fig. 206 pipework shall not be used for well testing operations downstream of the separator except for Burner Booms and 6-in. schedule #80. The burner boom is using 206 due to weight constraints. The 6 in. 206 is used because 6 in. 602 does not exist.”

Added, “Any deviation from the guidelines listed herein requires an exemption as per the Management of Change and Exemption Standard (OFS-QHSE-S010).”

**Section B.1.5.3 Figure 206 Hammer Union**

Added, “and to burner booms” to “Pipework with Figure 206 Hammer Unions shall be rated for a maximum Working Pressure (WP) of 1500 psi. Also, its use shall be limited to 6-in. Schedule 80 and to burner booms for gas flare lines downstream the separator.”

Added, “Any deviation from the guidelines listed herein requires an exemption as per the Management of Change and Exemption Standard (OFS-QHSE-S010).”

**Section B.2.7 Pressure and Temperature Rating**

Corrected the Table Reference to read “See Section 3, Table 3.3 COFLEXIP /Coflon Data of manufacturer specifications”.

## *F.7.12* Appendix C Amendments, Revision 5.2, January 31, 2006

Major revisions: none.

Minor revisions:

**C.0 Local Manufacturing and Procurement**

Added “Region” in the sentence, “Training and certification of this Supervisor is provided by the Technology Center upon request of Area, Region or Geomarket Management.”

## *F.7.13* Appendix D Amendments, Revision 5.2, January 31, 2006

Major revisions: none

Minor revisions:

Changed Appendix D title from “NACE MR-0175” to “NACE MR-0175, 2001 Edition”. Clarifies that this Appendix is currently based on NACE MR-0175, 2001 Edition.

## *F.7.14* Appendix E Amendments, Revision 5.2, January 31, 2006

Added new sub-sections to capture modifications for Revision 5.2 of the WCP Pressure Operations Manual dated January 31, 2006. Replaces Revision 5.1 dated May 17, 2005.

## *F.7.15* Appendix F Amendments, Revision 5.2, January 31, 2006

Eliminated this Appendix because it is obsolete.

## *F.7.16* Appendix G Amendments, Revision 5.2, January 31, 2006

**Major revisions:**

Renamed to Appendix F due to the deletion of Appendix F.

**Minor revisions:**

Promote form to version 3.2 based on the following:

- Correct typo, duplication of audit point 7.7
- Correct point 11.17 to indicate that all shop pressure equipment to be painted light grey.

# *F.8* Revision 6.0, January 31, 2008, Release Notes

Revision 6.0 replaces the “WCP Pressure Operation Manual” Revision 5.1 dated January 31, 2006.

In summary, Sections 3, 5, 6 and 9 and Appendix A,B and C contain several major revisions. Sections 6, 9, and Appendix A are documented as being shared between TS and WIRELINE. The other Sections and Appendices are TS specific. These remaining Sections or Appendices contain limited major revisions and/or only minor revisions.

The details of the changes of each Section or Appendices are posted at the end of each Section or Appendices and within the following sub-paragraphs E.2.7.1 through E2.7.16

## *F.8.1* Section 1 Amendments, Revision 6.0, December 31, 2007

**Major revisions: None.**

**Minor revisions: include.**

- Replace WCP by TS.
- Remove all comments related to completion.
- 1.2 Term and definition policy.
- Replace detailed revision history by a reference to the appendix E.

## F.8.2 Section 2 Amendments, Revision 6.0, December 31, 2007

**Major revisions: none.**

**Minor revisions include:**

- Replace WCP by TS.
- 2.3.2 Rented Equipment.

Addition of a control of the rented equipment age

- 2.3.3 Client Supplied Equipment.

If client is not in conformance with the POM an exemption must be raised

- 2.6.1 Annual Survey.

Addition of a Note to clarify certifying authority witness

- 2.6.3.5 Hardness Test.

Define When Hardness test is required

- 2.6.6 Equipment Repair / Remanufacturing.

Addition of a reference to appendix C for detail process

- 2.7.1 Section 2 Revision History

Replace detailed revision history by a reference to the appendix E.

## F.8.3 Section 3 Amendments, Revision 6.0, December 31, 2007

**Major revisions include:**

**Section 3.3.2**

Clarification on the 20 % WP safety margin used to select the Surface Well Test Equipment pressure rating.

**Section 3.4.2**

Recommendation the use of a Check valve on the kill line.

**Table 3-6.4**

Redefined SS0. and add a note concerning the use of HiPack BPCV.

**Section 3.4.5**

Review The paragraph related to the design of HPHT jobs.

**Section 3.4.6**

Addition of non $H_2S$ hoses (black eagles) into this section.

Addition of a note about the usage of low pressure rubber hoses.

**Table 3-7**

Included non $H_2S$ hoses specifications into this table.

**Section 3.4.7**

Remove from this section the sentence regarding the working pressure of the up stream choke manifold valves.

**Section 3.4.8**

Included a comment to banned the use of NPST.

Replaced Chiksan by articulated pipework.

**Section 3.4.8.1**

Added a reference to Architest software.

**Section 3.4.8.2**

Removed from this section the comment forbidding the use of Teflon tape.

Added a comment allowing for relief the use of one reduction just on the outlet of PSV.

**Section 3.4.9**

Clarification on the usage of gauge tank Offshore.

**Section 3.5**

Clarification on the pressure test to perform in case of partial rig down.

**Section 3.5.1**

Addition of reference to section 3.3.2.

Clarification on well site pressure test.

**Section 3.6**

Addition of reference to appendix C.

**Section 3.6.4**

Addition section to define HPHT / HQ operation.

**Section 3.7.1**

Addition of a note for the retirement of equipment of more than 20 years as per SWT equipment guidelines.

**Section 3.7.2**

Review requirement for PSV calibrations.

Remove comments related to HPTS (Artificial Lift).

Addition of a Note to clarify certifying authority witness.

**Section 3.7.3**

Remove all text from this section and added a reference to the appendix C.

**Section 3.8.4**

Remove this section.

**Section 3.9.2**

Remove this section as it is related to Artificial Lift.

**Minor revisions include:**

- Replace WCP by TS.

- Section 3.10.

Replace detailed revision history by a reference to the appendix E.

## F.8.4 Section 4 Amendments, Revision 6.0, December 31, 2007

**Major revisions include : None**

**Minor revisions include:**

- Replaced WCP by TS.
- Section 4.11.

Replace detailed revision history by a reference to the appendix E.

## F.8.5 Section 5 Amendments, Revision 6.0, December 31, 2007

**Major revisions include:**

- Remove content related to completion.
- Table 3-6.4.

Redefined SS0. and add a note concerning the use of HiPack BPCV.

- Remove section 5.3.3.

**Minor revisions include:**

- Replaced WCP by TS.

## F.8.6 Section 6 Amendments, Revision 6.0, December 31, 2007

**Major revisions include:**

**Section 6.1**

- Updated section with respect to Pressure Testing Requirements particularly to sample bottles with US-DOT and TC recertification requirements.

- Removed Tables 6.1 and 6.2 (Example Test Pressures for Oilphase-DBR sampling tools and sample receptacles).

**Section 6.3.2**

- Added Following Section.

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**Note**

When filling any US-DOT Gas Sample Bottles with Hazard Class 2.3 (i.e. samples containing $H_2S$), it is prohibited to fit a pressure relief devise, and forbidden from transporting that particular cylinder by Passenger and Cargo Aircraft. In this case blanking plugs should be fitted in place of the pressure relief devises as standard.”

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**Section 6.6.4.1**

- Expanded following statement to include and which meet SLB minimum standards. i.e.

  “When connecting to a Wireline sample chamber, use only specified Schlumberger/ Oilphase-DBR equipment or items that are marked and can be identified as having a pressure rating higher than the expected bottle pressure (formation pressure) and which meet Schlumberger’s minimum standards as per the Testing and Wireline POM.

**Section 6.5**

- Added “. The Sample Management Standard (See InTouch Content I.D. 4214962)” must be followed.

**Section 6.6**

- Added “When Schlumberger personnel or 3rd party companies contracted by the client are connecting pressure equipment to a Wireline sample chamber, only specified Schlumberger/ Oilphase-DBR equipment or items that are marked and can be identified as having a pressure rating higher than the expected bottle pressure (formation pressure) and which meet Schlumberger’s minimum standards as per the Testing and Wireline POM can be used.”

**Section 6.6.5**

- Section completely rewritten and expanded this section regarding minimum requirements for Sample Conditioning including:
  - 6.6.5.1 Wellsite Sample Conditioning

  - 6.6.5.2 Fluids Analysis Laboratory Sample Conditioning
    * 6.6.5.2.1 Extended Heating of Reservoir Fluid Samples
    * 6.6.5.2.1 Extended Heated Storage in an Oven

**Table 6.5**

- Table 6.5 Updated with Compact Production Sampler

**Section 6.7.1**

- Added “Ensure correct body position for task, i.e. body out of the line of fire, fingers away from bleedholes

**Section 6.9**

- Added Link to InTouch Content I.D. 4300827 for Sampling Seal Selection Recommendations Chart and Information.

**Section 6.11**

- Replaced Web EPU with InTime Section 6.12.

**Section 6.12**

Replace Rite with RITE.Net

**Minor revisions include:**

- Replace WCP with Testing Services or Oilphase throughout section.
- Replace Oilphase-DBR Product Centers with Oilphase Product Center and DBR Technology Center to reflect current naming.

## F.8.7 Section 7 Amendments, Revision 6.0, December 31, 2007

**Major revisions: None**

**Minor revisions include:**

- Replaced WCP by TS.

## *F.8.8* Section 8 Amendments, Revision 6.0, December 31, 2007

**Major revisions None.**

**Minor revisions include:**

- Replaced WCP by TS.

## *F.8.9* Section 9 Amendments, Revision 6.0, December 31, 2007

See Wireline release notes.

## *F.8.10* Appendix A Amendments, Revision 6.0, December 31, 2007

**Major revisions include:**

Section A.7

Removed comment saying that gas testing is not allowed outside a pressure test bay.

Addition of comments to recommend the use of blast walls portable pressure test bays, etc…

Added the requirement to prepare an HARC when performing a pressure test outside a pressure test bay.

**Minor revisions include:**

- Replaced WCP by TS.

## *F.8.11* Appendix B Amendments, Revision 6.0, December 31, 2007

**Major revisions include:**

**Table B-1**

Addition of 8” and 10” piping for relief line

**Table B-3**

Addition of 15 kpsi hub pipework

**Section B.2.7**

Addition of this section to cover pipework certification.

**Section B.3**

Addition of requirement for non $H_2S$ flexible Hoses (Black Eagle).

Addition of a Note regarding the use of low pressure flexible hoses.

**Section B.3.6**

Addition of requirement for non $H_2S$ flexible Hoses (Black Eagle).

**Section B.3.11**

Reviewed flexible hose inspection requirements

Minor revisions include: •

- Replaced WCP by TS.
- Replaced Coflexip by flexible hoses.

## F.8.12 Appendix C Amendments, Revision 6.0, December 31, 2007

**Major revisions include:**

Added section C5 SRPC - Testing Services Equipment Repair Process Chart

**Minor revisions include:**

- Replaced WCP by TS.

## F.8.13 Appendix D Amendments, Revision 6.0, December 31, 2007

**Major revisions: None.**

**Minor revisions include:**

- Replaced WCP by TS.

### F.8.14 Appendix E Amendments, Revision 6.0, December 31, 2007

Major revisions include:

Addition of detailed revision notes for each POM Section and/or Appendices.

**Minor revisions include:**

- Replace WCP by TS.

### F.8.15 Appendix F Amendments, Revision 6.0, December 31, 2007

**Major revisions include:**

Updated the location of the SDA.

## F.9 Revision 7.0, January 31, 2011, Release Notes

Revision 7.0 replaces the “WTS Pressure Operation Manual” Revision 6.0 dated January 31, 2008.

General change from “Well Testing Services” to “Testing Services” and from “WTS” to “TS”.

General change from “Service Delivery Manager” to “Quality Operations Support Manager”.

General changes from “Well Testing Services Catalog” to “In Time” or “OneCAT” as appropriate,

In summary, Sections 1, 2, 3, 4, 5, 6, 7, and Appendix A, B, C, D, E, F contain several major revisions.

## F.9.1 Section 1 Amendments, Revision 7.0, January 31, 2011

Major revisions:

1.1 Insertion of 6th paragraph: "No exceptions to any of the requirements of this manual are allowed unless approved through the QUEST exemption process (OFS QHSE Standard#10)."

1.3 Validity and Implementation Schedule. Section deleted.

1.5.3 Paragraph updated as follows: "API specifies a TP = 2 x WP or" replaced by: "API and ASME specify".

1.6 Modification of figure 1–1.

1.8.1 Modification of the 3th bullet: "tests (RITE)" becomes "tests" in bold character.

Modification of the 4th bullet: insertion of the sentence "Pressure Tests above WP must only be carried out in a Test bay meeting the requirements of Appendix A."

1.8.2 Modification of the 3th paragraph. Old text: "fluid test" new text: "test fluids".

Rewriting of 4th paragraph.
Old text: "Pressure testing equipment in Categories 1 and 2 with diesel, well fluids or other flammable fluids is forbidden. Pressure testing of DST equipment (Category 3) with diesel is not recommended, unless under the conditions specified in Section 5.5: Pressure Testing. Only Testing Operations Support can grant an exception to this rule."
New text: "Pressure testing equipment in Categories 1 and 2 with diesel, well fluids or other flammable fluids is forbidden. Pressure testing equipment in Category 3 with diesel is forbidden, unless performed under the conditions specified in Section 5.5: Pressure Testing. Only Testing Operations Support can grant an exemption to this rule."

1.8.3 Paragraph modified as follows:
General rules; 6th bullet: "hydrocarbons" becomes "hydrocarbons or hydrocarbon derived substances such as grease."

General rules; 8th bullet: "Inplant-manufacturing gas test procedure." deleted.
Update of the sentence: "The equipment shall bec ompletely submerged in a waterpool." by Whenever possible, the equipment shall be completely submerged in a waterpool to aid leak detection:"

Insertion of new Information Note: “Danger: "Potential Severity: Catastrophic - Potential Loss: Assets Hazard Category: Pressure - When bleeding off the pressure after completing a pressure test with gas, it is necessary to perform a staged pressure reduction process to prevent seal damage due to rapid (explosive) decompression. This is done by bleeding down the Nitrogen or other inert gas from test pressure to between 1200 and 1000 psi and then holding for 10-15 minutes. The remaining gas should then be bled off at a uniform rate of approximately+/-100 psi every 10-15 minutes."

1.91. First sentence, insertion of the word “tools”, second sentence updated as follows: "Completion" becomes: "Perforating and auxiliary downhole equipment".

1.9.2 Pressure testing of equipment in category 3 (DST tools) with diesel is now forbidden (formerly “not recommended”) unless certain conditions are adhered to.

In the second bullet, “see Section 2.6 Asset Maintenance RITE.net” becomes: “see Section 2.5: Asset Maintenance - RITE.Net”.

## *F.9.2* Section 2 Amendments, Revision 7.0, January 31, 2011

Major revisions:

2.1.1 Change from location Audit / SDA to Compliance Assessment Tool (CAT).

2.2 Revisions to the entities responsible for the update of the Asset history file.

2.4 and Sub Sections, 2.5 and Sub Sections: Re-arrangement into a more logical sequence, and with updates to specify the use of RITE.Net.

2.4.3 Clarifications on the equipment status and traceability requirements when replacing or repairing parts.

2.4.4 revisions to the requirements when making reception of new equipment, and also to reflect the creation of product centre manufactured equipment in RITE.Net by customer services.

2.5.1.3 new requirement for “in survey” status of equipment at the date of load out.

2.5.1.4 Clarifications on the requirements for crack testing.

2.6 New section on File Codes in RITE.Net.

2.6.1 New section on file codes for downhole and below flowhead crossovers.

## F.9.3 Section 3 Amendments, Revision 7.0, January 31, 2011

Major revisions:

3.3.2 Complete re-write on the selection of equipment working pressure, detailing the requirements for exemptions to operate under reduced safety margins.

3.4.1 Clarification on the definition of “Pressure Barrier”.

3.4.4 Clarification of the well conditions which require an E-Z valve to be used, updated to reflect the obsolescence of the 10K E-Z Valve, and inclusion of a new statement defining that the Subsea Tree or E-Z valve are not to be used as lubricator valves. Clarifications to the note on the use of a HiPAck.

3.4.6 Revised details for the applications which can utilize a Black Eagle hose, inclusion of details of job exposure recording requirements for all flexible hoses.

3.4.8 Technical details of pipework moved to Appendix B, addition of a note about allowing for the thermal expansion of pipework when rigging up.

3.4.8.1 Additional requirements for checking the thickness of pipework added.

3.4.8.2 Completely re-written section on Tie-down systems for surface piping.

3.4.9 Completely re-written section on API Threads.

3.4.10 Completely re-written section on fittings.

3.4.10.1 New section with the details on the checking of NPT threads.

3.4.11 New section on Chemical injection, specifically banning the use of oxidizer.

3.4.12 Revised to include the use of N2 or Separator gas pressure to prevent a partial vacuum forming in Surge Tanks.

3.5.1 Partially re-written to clarify the definition of MAOP.

3.6 Completely re-written section on Special Operations.

3.6.3 Revision of section to include the induction of extreme cold conditions by operations.

3.6.5 New section on the production of solids.

3.7 Completely re-written section on Special Safety Certification, Shop Maintenance and Quality Control.

3.7.1 Revised requirements for the major Survey of the SSV.

3.8.1 Clarification that pressure containing or controlling equipment must only be procured through a Sclumberger Product centre.

## *F.9.4* Section 4 Amendments, Revision 7.0, January 31, 2011

Major revisions:

4.3.1 Definitions of the job conditions which require the use of a Retainer valve added. Complete re-write on the selection of equipment working pressure, detailing the requirements for exemptions to operate under reduced safety margins.

4.5 Specification requirements for crossovers updated to include Tensile loading and Working Pressure requirements.

4.6.1 partially re-written to clarify the definition of MAOP.

4.8.1 Revisions to the entities responsible for the update of the Asset history file.

4.8.2 Clarifications on the design approval certificate requirements for Subsea equipment.

4.8.4.2 Updates to the TRIM Check Requirements.

4.8.4.3 Statement that the body test should be to Test Pressure added.

4.8.5 Clarifications on the equipment status and traceability requirements when replacing or repairing parts.

4.8.6 Requirements for serial number marking added.

## *F.9.5* Section 5 Amendments, Revision 7.0, January 31, 2011

Major revisions:

5.2.2.4 Specification requirements for Tool Joints and Crossovers updated to include Tensile loading and Working Pressure requirements.

5.3 Complete re-write on the selection of equipment working pressure, detailing the requirements for exemptions to operate under reduced safety margins.

5.3.2 Clarification of the well conditions which require an E-Z valve to be used, updated to reflect the obsolescence of the 10K E-Z Valve, and inclusion of a new statement defining that the Subsea Tree or E-Z valve are not to be used as lubricator valves.

Clarifications to the note on the use of a HiPAck.

5.5.1 Inclusion of a new rule in respect of the MAOP. Sections on Product Certification and quality control moved to chapter 7.

## F.9.6 Section 6 Amendments, Revision 7.0, January 31, 2011

Major revisions:

6 New Warning regarding High Pressure Injuries and need for immediate specialized treatment.

6.1.1 Updates to Table 6-1 Pressure Ratings of Wireline Sample Chambers.

6.3.2 GSB – update on the actions to be taken if aluminum bottles are exposed to mercury.
Addition of obsolescence age.
Addition of information on DBR sample bottles.

6.3.3 New section on pressure relief devices.

6.4 Updates to table 6-2 Wireline Sample Chamber Ratings.

6.5 Update to standards covering the transportation of samples.

6.6.1 and 6.6.2 inclusion of “Receptacles”.

6.6.6 Requirement for outstanding duration of certification before use added.

6.6.7 Update to the references to use to confirm the temperature/pressure limits of sample receptacles/cylinders.

6.6.7.2 Addition of technical requirements for sample conditioning equipment.

6.6.7.3 New section on the maintenance of sample conditioning equipment.

6.6.9 New section on the use of Pycnometers.

6.6.10 New section on pressure bleed down of sampling tools and receptacles.

6.7 Update to the requirements for fittings.

6.7.2 New section on connection of equipment to pressurized systems.

6.7.3 New section on liners and tubing.

6.7.4 New section on hoses.

6.7.5 New section on fitting connections.

6.7.6 New section with requirements for earthing.

6.9 Updates to special operations conditions and Environmental limits.

6.9.1 New section on the requirement for the use of an SDP.

6.9.1.1 New Section on product Metallurgy Limitations.

6.9.1.2 New section on Elastomer selection guidelines.

6.9.2 Updates to the references for $H_2S$ operations.

6.9.3 New Section on HP/HT Operations.

6.9.4 New section on Ultra HP/HT operations.

6.9.5 New Section on Aggressive and Harsh Environments.

6.10.3.1 New section on dealing with samples in receptacles which have an expired Major Certification.

6.10.4 Updated to align with RITE.Net terminology.

6.11.5 New section with the requirements for third party supplied sample receptacles.

## F.9.7 Section 7 Amendments, Revision 7.0, January 31, 2011

Minor revisions:

7.2 First sentence, “Completion and perforating equipment designed by Schlumberger” changed in “Perforating and auxiliary download equipment designed by Schlumberger”.

Latest sentence, “Ratings of Schlumberger supplied equipment are published with the datasheet of completion and perforating components.” changed in “Ratings of Schlumberger supplied equipment are published on equipment and product datasheets.

7.3 Whenever downhole conditions exceed any one of 330 degF [165 degC], 15,000 psi and 100 hr; consult with the Product Center via InTouchSupport.com.” changed in “Whenever downhole conditions exceed any one of the following conditions: 330 degF [165 degC], 15,000 psi and 100 hr; consult with the Product Center via InTouchSupport.com.”

7.4.1.2 5th paragraph, IFSU-T changed in IFSU/EFIRE.

7.6 and sub sections on Product certification and Quality Control. Moved from section 5, and updated to reference critical well requirements.

## F.9.8 Section 8 Amendments, Revision 7.0, January 31, 2011

Major revisions:

Updated to reflect the change from LMS to iLearn. All sections also updated to include requirements for maintenance personnel. Requirements for Managers also added.

## F.9.9 Section 9 Amendments, Revision 7.0, January 31, 2011

No changes.

## F.9.10 Appendix A Amendments, Revision 7.0, January 31, 2011

Major revisions:

A.2.3 Clarifications of the safety devices required in a pressure test bay.

A.5 Updated with the requirement to upload pressure test records to RITE.Net.

A.7 New section with the requirements for an Annual Survey of the pressure test bay itself.

A.9 Clarification of pressure test requirements.

A.10 Clarification of the person responsible for the pressure test bay.

## F.9.11 Appendix B Amendments, Revision 7.0, January 31, 2011

Major revisions:

B.2.1 Clarification on the pressure rating of 1502 pipework.

Revised pipework tables giving operating temperature ranges and strength of materials.

B.2.2.1 Clarification of the design stress used in standard pipework equations.

B.2.2.2 Revision of the formula used in High pressure piping equations.

B.2.3 Revision of the table Working Pressure Color Bands.

B.2.4.2 2 in. Fig 402 Pipework is forbidden.

B.2.4.4 New Section. 2202 pipework is now forbidden except for flushing lines.

B.2.4.5 Threaded unions are now allowed on low pressure (< 285 psi WP) flexible hoses.

B.2.4.11 New section clarifying procurement of pipework crossovers, replacement piping, and flexible hoses.

B.2.5.1 Clarification on welded vs Integral pipework design and construction.

B.2.5.3 New section on the design and use of Grayloc connectors.

B.2.5.6 New section giving the effect of temperature on the WP rating of ASME / ANSI flanges.

B.2.6.3 Completely re-written section on Hammer union mismatch risks.

B.2.6.4 Clarification on the direction of flow through hammer union pipework.

B.2.7 and Sub Sections: New sections on pipework Maintenance and certification procedures and requirements.

B.3 Section is now generic for flexible Test Lines, with reference to the Manufacturer's user guide for specific details of the Coflex hoses.

B.3.1 Statement of the correlation between the maintenance terms used in the Coflexip users guide and RITE.Net.

B.3.8 Revised section on the aging of Flexible hoses.

B.4 and Sub Sections: New sections on specifications, use, and maintenance requirements for low pressure flexible hoses.

B.5 and Sub Sections: New sections on specifications, use, and maintenance requirements for medium and high pressure flexible hoses and liners.

## F.9.12 Appendix C Amendments, Revision 7.0, January 31, 2011

Major revisions:

C.2 Updates to the Regional Manufacturing Process.

## F.9.13 Appendix D Amendments, Revision 7.0, January 31, 2011

Major revisions:

Updated to reflect the release of the 2009 (second Edition) of NACE.

## F.9.14 Appendix E Amendments, Revision 7.0, January 31, 2011

Major revisions:

New Appendix – Reservoir Sampling and analysis $H_2S$ standard.

## F.9.15 Appendix F Amendments, Revision 7.0, January 31, 2011

Major revisions:

Old Appendix E - Update of Revision History, Revision 7.0, January 31, 2011

Update.

### F.9.16 Appendix G Amendments, Revision 7.0, January 31, 2011

Deleted.

## F.10 Revision 7.1, February 2011, Release Notes

Revision 7.1 completes the Revision 7.0 dated January 31, 2011.

### F.10.1 Section 1 Amendments, Revision 7.1, February 2011

Minor revision:

Section 1.3 “Validity and implementation schedule” needs to be deleted.

### F.10.2 Section 2 Amendments, Revision 7.1, February 2011

Minor revision:

Information note added to the end of section 2.5.3 with text as follows: “In order to minimize the risk of internal corrosion, pressure test fluids must be properly drained from the equipment on completion of the test and the equipment stored, with any valves in the open position, in a dry, well ventilated area, and ideally under a high roof.”

The listing of major survey requirements in section 2.5.1.4 needs to be re-arranged.

Text of the first sentence of section 2.5.1.5 as follows:
"Any usage of the equipment shall be recorded in a RITE.Net Service Report. This includes use in corrosive environments ($H_2S$, $CO_2$, acid), sand production, over-pressuring, high temperature, excessive bending or tensile loads and any other exceptional condition which may affect the future performance of the equipment."

Some adjustments made to the text of the first paragraph in section 2.6 as follows:
“For equipment manufactured in a Product Centre, the File Codes (also referred to as Asset Codes) are created in GeMS by the manufacturing engineers. They are then migrated to OneCAT along with other engineering details. RITE.Net then imports the File Codes from OneCat and a RITE.Net administrator assigns

the required maintenance events and measure points before releasing the code for use. Product Centre manufactured equipment is created in RITE.Net at the time of completion and is then transferred to the purchasing location at the time of physical shipment."

## F.10.3 Section 3 Amendments, Revision 7.1, February 2011

3.4.6 Text modified as fllows: "Testing Services strongly recommends that Coflexip hoses be procured with API or Grayloc hub connections, as these do not have the angular rotation restrictions which bolted API flanges have." (There are words repeated between "bolted" and "API" in the POM V 7.0).

3.4.8 The text on page 3-24 starting "At the end of a restraint line…" through to "Re-certification of roundslings which are used for pipework restraint systems is not required" (Roughly ¾ of the page) is repeated. Delete the first time it appears (The second time it appears, the first paragraph is split into two, starting "At the end…" and "Post job the slings…" which is the correct format).

An unnecessary link has been added in section 3.4.8.2 – The second link should be replaced by the word "table" Figure 3-1: Polyester Roundsling Application Chart shows the colour code or tag number of the roundsling required for given sizes of pipework and operating pressures. A strength reduction allowance for the use of reef knots to join or secure the roundslings has already been built into the colour codes and tag numbers shown in the Figure 3-1: Polyester Roundsling Application Chart. table.

Section 3.5.1, the following paragraph has repeated text which needs to be deleted. "Since wellsite pressure test naturally takes place in an open area (i.e. not in a pressure test bay), the area must be adequately secured by using warning signs, barrier tape and clearing the area from all unnecessary personnel while pressure testing is in progress. Refer to Section A.8 Pressure Tests Outside a Test Bay for further details and procedures for further details and procedures.

3.7.2 Missing link. All Hammer unions (either piping or attached to main assets) shall be inspected following procedures set out in Section .B.2.7.3

## F.10.4 Section 4 Amendments, Revision 7.1, February 2011

Update the 4th bullet point of section 4.8.1 to: "A printed copy of the RITE.Net history card. (Updated regularly by the Geomarket/Location)."

## F.10.5 Section 5 Amendments, Revision 7.1, February 2011

Text added to section 5.5.1 rule 6: "When pressure testing with the assembly in the hole, it is recommended to have the diesel-water interface below SenTREE or EZ-Valve, or at a level below the rig floor if the subsea valve has not been run. This will minimize the risk of a direct diesel to air contact."

## F.10.6 Section 6 Amendments, Revision 7.1, February 2011

6.2.3 first paragraph, there should not be a space between Phase and Sampler – it should be: This covers surface equipment designed to handle pressure and flow (e.g., PhaseSampler, Wellsite Sampling Module, Surface Sampling Manifolds) Category 1.2 equipment.

## F.10.7 Appendix A Amendments, Revision 7.1, February 2011

Last paragraph of Section A8, the word “will” should start with a lower case letter: “Pressure testing outside a pressure test bay at the wellsite does not require an exemption, but will normally require a work permit issued by the drilling contractor.”

## F.10.8 Appendix B Amendments, Revision 7.1, February 2011

B.2.1 Pipework tables B-1, B-3, B-4 have been modified as follows:
The Pipework tables have some errors – these are given on separate files in red text, but in summary:
B-1 has the wrong minimum tensile strength for the 6" 5K WP pipe, and the material should have an asterisk after it. The note about the 6" 1002 has the wrong material, and the temperature range for the A333 gr 6 material is wrong. There are also a couple of changes to the note below the temperature ranges.
B-3 has the wrong nominal wall thickness for the 4" 15K WP pipe, and there are some changes to the note below the temperature ranges.
B-4 has the wrong Pipe Nominal size and OD in the second row (This is for 10" pipe, not 4"), the wrong temperature range for the A333 gr 6 material, and we need to add the note below the temperature ranges.

B.2.4.7 have be renamed as “Use of Schedule 40 Pipework”

The third paragraph of section B.2.4.9 have be splited so that it looks as follows: The schedule 80 piping with 6 in. Fig 206 connections is allowed downstream of the separator because 6 in. 602 does not exist. The schedule 40 piping with fig 206 connections is used on the booms due to weight constraints. Any deviation from the guidelines listed herein requires an exemption as per the Management of Change and Exemption Standard (OFS-QHSE-S010).

B.2.4.10 “Schedule 40 Pipework is Forbidden” deleted (it is a repeat of section B.2.4.7) and section B.2.4.7 to be renamed as “Use of Schedule 40 Pipework”.

Second Paragraph of section B.2.7.3 has modified as follows: The survey results shall be added into the equipment quality file and RITE.Net shall be updated. Additionally the Pipework shall be colour coded as described below.

Section B.3, a comma inserted after "leakage as follows: “Hammer union terminations should be avoided as hammer union saver subs have a greater risk of leakage, and damage to the union on the hose termination would require the hose to be re-swaged. The terminations interface between the fixed attachment points”.

Appendix D still pending update (see separate document)

## F.10.9 Appendix D Amendments, Revision 7.1, February 2011

Title of Appendix modified: “NACE MR-0175/ISO 15156, Second Edition 2009” becomes NACE MR-0175/ISO 15156, Second Edition 2009.

Modification of text as follows:
Part 2: Cracking-resistant carbon and low-alloy steels, and the use of cast irons.
Part 3: Cracking-resistant CRAs (Corrosion Resistant Alloys) and other alloys.

“Region 1 and 2 - certain grades of tubing and tubular components like UNS G41XXO, formerly AISI 41XX are acceptable with hardness higher than 22 HRc, but lower than a hardness which is specific to the grade of material, with proper qualification.”

D2 as a general guideline, carbon and low alloy steels are acceptable at a maximum hardness of 22 HRC (Rockwell C Hardness Scale units) equivalent to 237 B (Brinell Hardness) for carbon steel and 241 HB for alloyed steels, provided that they have less than 1% mass fraction of Nickel, are not free-machining steels, and are subject to certain heat treatment conditions.

Modifications of table D-1: “Alloy 17–4PH” becomes “UNS S17400” and “33” becomes “28–31”.

D3: text modified as follows: Table D-2: Conditions for 17-4PH lists the conditions under which 17-4PH may be used in testing tools subject to certain heat treatments which are required. Fluid sampling containers can be used to store sour oil without restriction. If water is present, then the pH should be equal to or greater than 4.5, and the $H_2S$ partial pressure less than 0.5 psi for short term or long term storage.

# F.11 Revision 8.0, February 2012, Release Notes

Version 8.0 of the Pressure Operations Manual represents an important rework of the standard with significant changes or additions in most sections.

A summary of the main changes are as follows:

POM Feedbacks, and POM related InTouch Tickets and Lessons learnt submitted since the release of POM V7.0 have been reviewed and integrated, or revisions made to make the requirements clearer.

## F.11.1 Legal information, Revision 8.0, February 2012, Release Notes

Third Party Trademarks

Minor revision:

Modification of the list “Third Party Trademarks”. Deletion of Hammer Union® Trademark.

## F.11.2 Section 1 Amendments, Revision 8.0, February, 2012

**Introduction and General Concept**

Major revisions:

1.1 Indication of the new Issue 8.0.
Adding of paragraph: It forms an appendix to both SLB Standard 14, Pressure (SLB-QHSE-S014), and SLB standard 22, Well Integrity (SLB-QHSE-S022).
Modification of the last paragraph of the section:
The Testing Services POM may be distributed to customers and regulatory authorities only with the prior approval of Testing Services Operations Support. No exceptions to, or deviations from, the requirements set out in this manual

are allowed unless duly approved through an approved exemption in QUEST (SLB-QHSE-S010) with final approval being given by Testing Services Operations Support Manager.

1.2 Add more definitions in the list.

1.3 Add more definitions and add abbreviations section.

1.6 General Concepts - Fundamentals of Design
1.6.1 Add informations in Table 1–1 Safety Factors.

1.6.3 Test Pressure (TP)

1.7 Categories of Pressure-Containing Equipment
Modification of the second paragraph: The Wireline Pressure Operations Manual (InTouch Content ID 3046294) primarily addresses the equipment shown pictorially in Figure 1-1: Categories of Pressure-Containing Equipment as being in Category 1.1. This manual, the Testing Services Pressure Operations Manual, primarily addresses the equipment shown as being in all the other categories. Both manuals cover hardware used for containing and controlling well pressure and/or well flow.

1.7.1 Category 1. Modification of the section.

1.7.2 Category 2. Modification of the section.

1.9.3 Rework and clarifications of Pressure Testing with inert gas.

1.10 Clarification on Well Barrier Element requirements
1.10.1 Quality file
1.10.2 Equipment Certification
1.10.3 Traceability
1.10.4 Certification Renewals.

## F.11.3 Section 2 Amendments, Revision 8.0, February, 2012

**Equipment Quality Control and Administration**

Major revisions:

2.3 Procurement: modification of the 3rd paragraph and adding of 2 notes.

2.3.1 Add of 2 paragraphs:

At a minimum the quality file must contain a manufacturer's pressure test certificate, an acceptance inspection certificate, and proof of regular pressure testing according to survey procedures. This documentation is to be augmented as required by local regulations and/or client's contractual requirements. Additionally, for equipment which is identified as being a "Well Barrier Element" (as defined in POM section 3: Well Integrity), the Quality File must contain any relevant test and inspection reports, Design Verification Reports, and a Certificate of Conformity or Product Certificate (all as described in POM section 1.10.2: Equipment Certification).

Modification of the last paragraph:

To be in accordance with API 6A, manufacturers must retain an original or a duplicate original of all quality and traceability records for a minimum of 5 years. The specification used by Schlumberger Product centres requires the manufacturer to keep the records for an increased period of 15 years, and a copy will also be kept by the product centre responsible for the manufacture of the equipment for an equivalent length of time. Duplicate originals or originals of these documents shall be filed in the location which owns the equipment, be retained over the lifetime of the equipment, and moved with the equipment if it is permanently transferred between locations.

2.3.3 Client Supplied Equipment

Add last paragraph with Figure 2-1: Client Owned.

New section 2.3.4 Non Schlumberger Contracted Service Company Equipment.

2.4.1 Equipment Identification and Marking

Modification of the text of the bullets.

New section 2.4.2.1 Qualification of Contractors

2.4.3 Replacement of Parts or Equipment Repair / Re-Manufacturing

Modification of paragraph 1, 2, 3 and 4.

Add new section 2.4.3.1 Repair / Re-Manufacuting Documentation

2.4.4 Modification of the text

Add a new last paragraph:

At the time of reception, any new equipment which has been in-transit for an extended period may be due, or nearly due, for a Q-Check without ever having been used. In such cases a normal reception control should be performed, and an exemption submitted against having to do any thickness checks which would normally be required for the Q-Check. If the exemption is approved, the reception control may then be recorded in RITE.Net as a Q-Check. If this is done the QUEST exemption number must be clearly stated in the RITE.Net Work Order.

2.4.5 Modification of the last paragraph:

Maintenance, repairs, inspections and utilization records (by way of Service Reports) shall be routinely entered into RITE.Net when, or immediately after, they are performed. Any parts replaced shall be noted in such a way that traceability is maintained. The date of the relevant RITE.Net Work Order will be used to indicate the validity of Q-Checks and Certification (Annual and Major Surveys).

2.5.1.2 TRIM (Tool Review and Inspection Monthly)
Add of the **Note**: When performing a TRIM on vessels, if the PSV's have not been removed for calibration it is accepted to pressure test at 90% of the PSV setting.

2.5.1.3 Q-Checks (Annual Survey)
Modification of the 5$^{th}$ paragraph:
Hydrostatic tests on surface piping shall be conducted at Test Pressure (TP). The requirements for WHE are detailed in the Wireline Pressure Operations Manual (InTouch content ID 3046294).
Add at the end of this section, the **Note**: PSV's must be removed from vessels and replaced with blank flanges at the time of an Annual Survey so that the pressure test can be performed at full WP.

2.5.1.4 Certification (Major Survey)
Add the paragraph: Before any Major Re-Certification work commences, an Inspection and Test plan which describes the work to be performed during the recertification process shall be in place, with clearly defined acceptance criteria for each inspection or test which is to be performed. This information should normally be available in the equipment manuals and/or POM, or from established working practices.
Add the bullets:
• A review of the original Quality File and records of replacement parts or repairs with special focus on traceability.
• A review of the design specifications.
• A review of the job exposure and maintenance records to verify the amount of operational history and the extent of maintenance performed.
and at the end of the section:
• A lifting proof-load test.
• A crack test of lifting eyes and structures after the load test.
Please refer to Appendix B for detailed pressure testing procedures.

New section 2.5.2 RITE.Net Service Report (Utilization Records)

New section 2.5.3 Work Order History Requirements

2.5.5 Pressure Test Requirements
Add to paragraphs:
A complete gas test is a body integrity test to Working Pressure, followed by a seat test to Working Pressure.
Please refer to Appendix B for detailed pressure testing procedures.

At the end of the section, add 1 paragraph:
A stamp similar to the example in Figure 2-5: Pressure Test Chart Stamp can be made and used to ensure all relevent information is captured on the test chart and Figure 2–5.

New section 2.5.7 Shelf Life of Elastomer O-Ring Seals.

New section 2.6.1 Downhole or Below Flowhead Crossover Codes.

## F.11.4 Section 3 Amendments, Revision 8.0, February, 2012

**Well Integrity**

Major revisions:

Inclusion of a complete new section on “Well integrity”.

## F.11.5 Section 4 Amendments, Revision 8.0, February, 2012

**Surface Equipment**

Major revisions:

Modification of all text of the Overview.

4.1.1 Test Pressure
Add Table 4-1: Test Pressure for Surface Testing Equipment.
Add **Warning**: Do not exceed the manufacturers Test Pressure rating of any component(s) of any surface equipment assemblies. In the 19th edition of API 6A, Specification for Wellhead and Christmas Tree Equipment, the ratio of TP to WP was reduced from 2 to 1.5 and it must be considered that some legacy documentation may not reflect this reduction of Test Pressure for 5000 psi Working Pressure equipment.
Add **Example**: If a valve body is replaced on an existing 5000 psi WP choke manifold, the valve body may have a Test Pressure rating of only 1.5 times the WP or 7500 psi while the other legacy sub-components of the choke manifold may have a manufacturer’s TP rating of 2 times the WP or 10,000 psi. In cases like this, the new Test Pressure rating of the choke manifold assembly shall not exceed any sub-component manufacturer’s Test Pressure rating and must be reduced to 1.5 times the Working Pressure, in this example - 7500 psi.

Update section 4.2 Standards and Specifications.

4.2.2 with regards to API 6A and PSL 3G.

4.2.3 Client Specific Standards (Old section 3.2.3).

New section 4.2.4 Job Design and Well Integrity.

New section 4.3 Surface Testing Equipment General Rules (Replacing old section 3.3).

Add Figure 4-1: Selection of Equipment Working Pressure with text.

4.4.1 Surface Pressure Barriers
Modification of the 1st paragraph.

4.4.2 Type of Valves for Category 1 Equipment (Old section 3.4.4).
Add items 2 and 3:
2. Large Bore strings where a large bore DST safety valve does not exist. In this case an E-Z Valve or Subsea Tree or SCSSV is strongly recommended for all wells where it is not already mandatory in the above table and a HARC must be developed to mitigate any safety concerns.
3. If WHP < 3,000 psi and there is an E-Z Valve or Subsea Tree or SCSSV in the string, then the requirement is relaxed to D1 only.

New section 4.4.3 Flowhead or Production Tree

4.4.4 Emergency Shutdown System
Add paragraph: In order to achieve closure in this time frame it may be required to add air and/or hydraulic quick exhaust (dump) devices to the ESD control systems.

New section 4.4.5 Flexible Test Lines

New section 4.4.6 Data Header

New section 4.4.8 Surface Relief Facilities

New section 4.4.9.1 Pipework Sizing

4.4.9.2 Tie-Down or Line Securing Systems
Add Figure 4-3: Polyester Roundsling Application Chart

New section 4.4.10 Pipework Check Valves

4.4.12 Fittings:
Modification of the text of the section.
Insertion of a tag “Danger”:

The installation of a needle valve, or of a fitting upstream of the needle valve, which has a lower WP than the WP of the equipment on which it installed lowers the WP of the equipment to that of the valve or fitting. It is recommended good working practice to install valves or fittings which have a WP equal to, or greater than, the WP of the equipment even if it is not required for the job which is being performed. If a valve or fitting which has a lower WP than the equipment on which it is installed is used, it must be clearly identified with a tag and changed for one of a suitable WP at the earliest opportunity. Locations are strongly encouraged to standardise on 10 kpsi rated NPT needle valves and fittings for all applications other than those where Autoclave is required.
Add of the **Note**: It is acceptable to have 10,000 psi WP field equipment fitted with 1/4 inch or 1/2 inch NPT fitting as this equipment is only taken up to 15,000 psi Test Pressure inside a pressure test bay.at the end of the section.

New section 4.4.12.2 Needle Valves

New section 4.4.12.3 Manifolds made from Fittings

New section 4.4.14 Transfer Pumps

New section 4.4.15 Tanks

New section 4.4.15.1 Surge Tanks

New section 4.4.15.2 Gauge Tanks

New section 4.4.15.3 Frac Flowback (Trash) Tanks

New section 4.4.16 Flame Arresters

New section 4.4.17 Hazardous Areas and Zones

New section 4.4.17.1 Hazardous Areas

New section 4.4.17.2 Non-Hazardous Area

New section 4.4.18 Fire Risk

New section 4.5 Wellsite Equipment Pressure Testing

4.5.1 Basic Wellsite Pressure Test (WPT)
Add Figure: Examples of the Wellsite Pressure Test for 10 Kpsi EquipmentModification of the text of the section

4.6.2 Nighttime Operations
Modification at the end of the section of the

**Note**: Painting the level type valve handles on the separator and diverter manifolds in bright colours or neon paint will help to identify the valve position when the lighting or visibility is marginal.

4.6.4 HPHT / HQ Operation
Modification at the end of the section of the
**Note**:
During HPHT or HQ operations, it is advisable to remove the thermowells or any other intrusive probe from the flow stream to reduce the risk of wash out and venting hydrocarbons to atmosphere.

4.6.5 Solids Production
Add a last paragraph: A number of third party companies can supply sand detection equipment. Please refer to InTouch Content ID 4272030 and InTouch Content ID 2045743 as examples.

4.7.1 Major Re-Certification
Modification of the Table 4-10: Major Re-Certification Requirements for Surface Well Test Equipment and Table 4-11: Major Re-Certification Requirements for Surface Well Test Equipment.
Add a note at the end of the section:

**Note:** With the exception of Burners, and independent from its' certification status, surface testing equipment must be retired and junked before a 4$^{th}$ Major Survey is required (Typically after 20 years service). For Burners the recommended retirement age is 15 years. Any deviation from this must be approved through an exemption in QUEST, approved at Area level, with a strong justification as to why the asset should not be retired.

4.7.2 Regular Inspection and Annual Surveys
Modification on the 8, 9 and 10 bullets:
• Fixed separator and surge tank piping must go through annual survey in accordance with the same requirements in respect of thickness testing and inspection as surface piping, but the pressure test to should be to the same value as the WP of the vessel to which it is attached. This means that the fixed piping does not need to be disconnected from the vessel and the whole assemply can be pressure tested at the same time.
• For large vessel inspections, refer to appropriate maintenance manual and to API Standard 510: Pressure Vessel Inspection Code.
• All elements shall be visually inspected for signs of damage, stress and surface defects. If any defect is observed the equipment shall be replaced and set aside for full NDT inspection and, if required, subsequent remanufacturing where certified repair facilities are available (refer to Appendix C) or be junked.

4.7.3 General Pressure Test Procedures are as follows
Modification on 5$^{th}$ bullet:

• Unless there is a specific requirent for a pressure test with gas, pressure tests should be performed with a nonvolatile, nonflammable, low compressibility liquid such as water or ethylene glycol.
and 13rd bullet:
• If equipment has to be gas tested, it must first be pressure tested to at least 1.2 times the pressure required for the gas test with a non-compressible (Hydrostatic) fluid. In no case, can the pressure test with gas exceed the rated WP of the equipment being tested. Gas tests have an inherent higher level of risk and safety precautions must be increased accordingly.

4.8 Equipment Procurement Guidelines
Add a new not at the beginning of the section:
**Note:** Although they operate at atmospheric pressure, gauge tanks are considered to be pressure containing devices and must only be purchased from a Schlumberger Product Centre.

## *F.11.6* Section 5 Amendments, Revision 8.0, February, 2012

**SenTREE**

Major revisions:

5.2 Standards and Specifications
Modification of the text of the bullets:
• API 5CT.
• API Specification 6A / ISO 10423:2009 (Modified).
• API Specification 14A5.
• API Specification 17G / ISO 13628-7.
• NACE MR-0175.

Add 2 paragraphs:
All Subsea Test Tree Valves shall be built and tested to a minimum of API Specification 6A / ISO 10423:2009 (Modified) PSL-3.
5.2.1.4 Modification of the second paragraph:
The minimum frequency for Major Re-Certification shall be five years. This is in accordance with the Det Norske Veritas recommended practice for the Recertification of Well Control Equipment. (DNV-RP-E101).

5.3 Job Design and Well Integrity
Maintaining the integrity of a well is paramount in delivering a safe, high quality, service to our clients. In addition to following all the measures required to maintain the integrity of individual tools (such as maintenance, certification and traceability of critical parts), at the wellsite the overall Well Barrier Envelope

must be established and maintained, and in order to do this all jobs performed with Subsea equipment must be designed and planned in accordance with POM section 3.2: Job Design, and Planning Well Barriers. The roles and responsibilities of each member of the crew must also be assigned, and this must take into consideration their levels of training and competence.

5.4 Subsea Safety Equipment General Rules
Two annular pressure barriers should be considered with respect to all Subsea wells. This is commonly provided by dual BOP ram closure on the slick joint for Sentree3 operations. For SenTREE7/HP Completion operations, it should be considered that when the TH (Tubing Hanger) is set, the annulus isolation sleeve seals and TH seals, plus the AAV (Annulus Access Valve) and XOV (Crossover Valve) in the HXT (Horizontal Christmas Tree) are the primary annulus barrier, and the pipe rams which are closed on the PSJ (Ported Slick Joint) are considered to be the secondary annulus barrier. At least one barrier test must be conducted in the well prior to any lifting or flowing the well.
Add at a **Note**: Annular preventers are not considered as well barriers.
Modify paragraph: A fluid is considered a barrier if the hydrostatic head of the fluid is greater than reservoir pressure and the height of the column can be monitored, with a reserve of fluid available for immediate use should it be required in order to maintain the height of the column. A job or project specific Hazard Analysis and Risk Control should be performed to identify and mitigate risks, particularly the risks associated with barriers for the annulus and the tubular wellbore.

5.5.2.2 Umbilicals and Injection Lines
Modification of the 1st paragraph.
Assembled lines (hoses and end connections) used in Subsea activities for hydraulic control and chemical injection shall generally conform to the requirements of POM section except for the Annual Survey pressure test being to a value of 1.1 * WP instead of 1.5 * WP, and not all hoses currently in the field will necessarily have been supplied with a COC. Specifically hoses used in Subsea activities must conform to the following minimum specifications:
Modification of the 6th item:
6. PVDF lined hoses are rated to a maximum temperature of 250 degF [120 degC]. Nylon 11 lined hoses are rated 160 degF [75 degC] for intermittent use and 120 degF [50 degC] for continuous use.

5.5.4 O'ring Seals
Add new last paragraph: The discard (ie disposal) date for a packet of unused O-rings should be printed on the packet label by the manufacturer. This date refers to a packet which remains sealed, and once the packet is opened the O-Rings must be used as soon as possible. The discard date printed on the packet will generally follow the schedule given in the table in section 2.5.7: Shelf

Life of Elastomer O-Ring Seals and in any case must always be observed. Limits for the maximum shelf life of O-Rings which are stored in open packets is also given in Table 2-3: Shelf Life of Elastomer O-Ring Seals.

5.6 Tool Joints and Crossovers
New text in this section.

5.10.1 Newly Purchased Equipment
Modification of the first paragraph:
Standard equipment approved for purchasing is listed in the InTime catalog. Requests for any non-standard, special or purpose built equipment, crossovers, slick joints, injection subs, or adapters and connections must be submitted to Rapid response via OneCAT. Direct purchase of tools or equipment to be used in the landing string from third pary manufacturers is forbidden.

New section 5.10.3 Equipment not owned or supplied by Schlumberger

Add a section about well integrity with Sub-Sea tree.

Clarification on utility supply hoses, umbilicals and injection lines.

Clarification on O-ring life time.

Clarification on tool joints and crossovers rework, remanufacturing and repair.

Clarification on Sub-Sea equipment procurement.

## *F.11.7* Section 6 Amendments, Revision 8.0, February, 2012

**DST**

Major revisions:

6.2.2.3 Maximum Operating Temperature
Modification of the second paragraph:
The temperature rating of DST, TCP equipment is a function of time and exposure. Refer to maintenance manuals and the Seal Selection Guidelines which are given in the document SH607414, attached to In Touch Content ID 3012741, the 15,000 psi PCT-F Field Operation Manual for detailed information.

New section 6.2.3 Job Design and Well Integrity

6.3 Downhole Equipment General Rules
Modification of the text of section 6.3:

A test of at least one pressure barrier must be conducted in the well prior to any lifting or flowing the well.

**Note:** Annular preventers are not considered as well barriers. A fluid is considered a barrier if the hydrostatic head of the fluid is greater than reservoir pressure and the height of the column can be monitored, with a reserve of fluid available for immediate use should it be required in order to maintain the height of the column. A job or project specific Hazard Analysis and Risk Control should be performed to identify and mitigate risks, particularly the risks associated with barriers for the annulus and the tubular wellbore.

New section 6.3.1 Maximum Potential Pressure and Selection of Downhole Equipment and Subsections (6.3.1.1 - 6.3.1.2 - 6.3.1.3 - 6.3.1.4.

6.3.3 Pressure Barriers for Drill Stem Testing
Modification of the table: Table 6-1: Number of Valves versus Well Para
Modification of the items 2 and 3:
2. Large Bore strings where a large bore DST safety valve does not exist. In this case an E-Z Valve or Subsea Tree or SCSSV is strongly recommended for all wells where it is not already mandatory in the above table and a HARC must be developed to mitigate any safety concerns.
3. If WHP < 3,000 psi and there is an E-Z Valve or Subsea Tree or SCSSV in the string, then the requirement is relaxed to D1 only.

6.3.5 O'Rings, Seals and Elastomers
Modifcation of the 3rd paragraph and creation of the two last paragraphs.

6.6.1 Basic Pressure Test Rules
Modification of the second item.
Add a last paragraph at the end of the 3$^{rd}$ rule: A graphic explaining the relationships between Equipment WP, the Wellsite Pressure Test, and exemption requirements is shown in section 4.5.1: Basic Wellsite Pressure Test.

6.7.1 $H_2S$ operations for DST
Add a section about well integrity with DST.

Clarifications on Tool Joints and Crossovers requirements and procurement.

Add a section about well integrity with DST.

Clarification on O-ring life time.

Clarification on DST tools NACE compliance.

## F.11.8 Section 7 Amendments, Revision 8.0, February, 2012

**Sampling and Analysis:**

Major revisions:

New section 7.2.6 Job Design and Well Integrity

7.10.5 Major Repairs/Re-manufacture
Clarification on local field maintenance and repairs of pressure containing sampling and analysis equipment.

7.11.2 Reception Control
Clarification on reception control requirement.

## F.11.9 Section 8 Amendments, Revision 8.0, February, 2012

**Perforating services**

Major revisions:

New section 8.3 Job Design and Well Integrity

New section 8.5.1.4 CIRP Deployment Stack
On CIRP deployment stack with drawing of basic deployment stack and links to WS QHSE Std. 22 for Coil Tubing Operations.
Clarification on the purchase of special equipment (purpose built, adapters, CIRP connectors, etc.)

8.6.1 Purchase of New Equipment
Modification of the paragraph.

8.8 Personnel Certification
Clarification on TCP personnel certification requirement on associated disciplines (SWT, CT, WHE, etc.)

## F.11.10 Section 9 Amendments, Revision 8.0, February, 2012

**Personnel Qualification and Administration**

Minor revisions:

Modification of the 1st paragraph of section 9:
The guidelines discussed herein address personnel qualification and administration for pressure operations. These guidelines are consistent with the Pressure Equipment Standard (SLB-QHSE-S014), the Well Integrity Standard (SLB-QHSE-S022) and the QHSE training proficiency guideline as per the Training and Competency Standard (SLB-QHSE-S005).

9.1.7 Third Party Personnel
Clarification about certification and quiz for 3rd party personnel.
New section 9.1.10 Well Integrity Certification

## F.11.11 Section 10 Amendments, Revision 8.0, February, 2012

**Wellhead Pressure Control Equipment**

Major revisions:

Remove complete section text and replace with reference to the Wireline and Slickline POM.

## F.11.12 Appendix A Amendments, Revision 8.0, February, 2012

**Pressure Test Bays**

Major revisions:

Clarification on fittings, needle valves and Plugs certification.

Clarification on the use of NPT fittings in Pressure Test bay up to 15 kpsi.

Clarification on hammer unions marking not being a reference for Working Pressure and Test Pressure of equipment.

Clarification of requirement of test bay for all pressure test post maintenance plus Major and annual surveys.

Clarification on exemption approval needed for test outside pressure test bay.

Add a section on Gas Testing procedure.

## *F.11.13* Appendix B Amendments, Revision 8.0, February, 2012

**SWT Pipework and Flexible Hoses**

Major revisions:

Clarification on the fact that pipework pressure rating is not determined by Hammer union rating.

Clarification on temperature rating of pipe material A333 gr6.

Revision of minimum wall thickness for 8” and 10” ASME Flanged 285 psi WP and addition of a comment below the table B-4.

Add a note to explain that the pressure used for thickness calculations should never be less than 1000 psi to avoid too thin thickness.

Add a section about Thickness Calculations for Pipework crossovers, tees and laterals.

Add a table with design stress value versus material used for crossovers.

Add a paragraph to explain that Schedule 80 or greater should be used for Pipework (except for flare booms and relief lines).

Clarify the use of Fig 206 hammer union.

New section B.2.3.5 All Sizes of Fig 2202 Hammer Unions are forbidden.

Add several clarification about API 6A flanges and spools regarding recommended bolt torque value and correct sequence to tight them.

Clarification on hammer union lip seal exposure to chemicals.

Highlight risk of hammer union mismatches when interfacing with client or 3rd party equipment and the need for Go No-Go use.

Clarification on thickness test during Pipework TRIM, Annual survey and Major survey.

Add requirement for maintenance of Pipework check valves (FIT, TRIM, Annual Major).

Add a note about maintenance of hammer union on Flexible hoses.

5.4 Subsea Safety Equipment General Rules (Old Section 5.3)
Transfert of the 6th first paragraph from section 5.4.1.
Add of the **Note:** Annular preventers are not considered as well barriers.
5.4.1. Modification of the title of the section: Maximum Potential Pressure and Selection of Sub Sea Equipment
Complete odification of the text of the section with adding of 6 subsections: 5.4.1.1 - 5.4.1.2 - 5.4.1.3 - 5.4.1.4 - 5.4.1.5 - 5.4.1.6.

B.5.1 Coflexip® Hose: clarification on maximum velocity.
Add a new first paragrap:
Testing Services use Coflexip® Drill Stem Test (DST) and Production Test Lines (PTL) for Flowline applications. These are distinct from other hoses in the Coflexip® range (such as the hoses for BOP Choke and Kill lines) and must not be confused with them, as the maintenance and certification requirements are not the same.
Add an information **Note:** In common with most other items of surface testing equipment, the maximum service life of a Coflexip hose is 20 years. Hoses older than this must be junked.
Add a paragraph on the use of low pressure flexible hose.
Clarification on the maintenance and inspection of medium and high pressure flexible hoses.

Re-arrangement of several sections in different order.

## *F.11.14* Appendix C Amendments, Revision 8.0, February, 2012

**Regional Manufacturing, local Remanufacturing and Repair of Pressure containing or controlling Equipment**

Major revisions:

Add a section on Crossover Redressing and Re-cuts.

Add a section on sub and tool joints Redressing and Re-cuts.

Clarify section “local remanufacturing and repair”.

Clarify vendor responsibilities.

Add a section on exceptions to the Appendix C.

## F.11.15 Appendix D Amendments, Revision 8.0, February, 2012

**NACE**

Minor revisions:

Minor spelling mistakes corrected.

## F.11.16 Appendix E Amendments, Revision 8.0, February, 2012

**Reservoir Sampling and Analysis $H_2S$ Standard**

Minor revisions:

Minor spelling mistakes corrected

## F.11.17 Appendix F Amendments, Revision 8.0, February, 2012

**Revision Release Notes**

Major revisions:

Integration of all the modifications of the Revision 8.0 of this Manual.

# F.12 Revision 8.1, December 2012, Release Notes

Version 8.1 of the Pressure Operations Manual represents an "minor" rework of the standard with changes or additions in certains sections.

A summary of the main changes are as follows:

POM Feedbacks, and POM related InTouch Tickets and Lessons learnt submitted since the release of POM V8.0 have been reviewed and integrated, or revisions made to make the requirements clearer.

## F.12.1 Section 1 Amendments, Revision 8.1, December, 2012

**Introduction and General Concept**

Added of a new section **1.1.1 Competency Knowledge Requirements**.

In section **1.3 Abbreviations**, in **psi** definition; adding of the sentence “Within the confines of the POM, Pressure expressed as psi (pounds per square inch) always refers to psig. Wherever Pounds per square inch absolute is denoted, "psia" shall always be specified.”
Adding of two other definitions:
**psia**: Pounds per Square Inch absolute (psia) is used to make it clear that the pressure is relative to a vacuum rather than the ambient atmospheric pressure. Since atmospheric pressure at sea level is around 14.7 psi, psia = psig + 14.7 for any pressure measurement made in air at sea level.
and
**psig**: Pounds per Square Inch gage (psig), indicates that the pressure is relative to atmospheric pressure.

Section **1.6 General Concepts - Fundamentals of Design**, modification of the last paragraph which becomes:
“For Surface well testing equipment where the Design method is “Yield based” such as with API 6A, at no time, whether while “pressure testing” or “operating”, shall the combined stresses reach or exceed a magnitude that causes the Yield Strength to be exceeded. Calculating the combined stresses is one of the critical planning stages of any completion application design.”
Adding of 2 others paragraphs:
For Subsea Test Trees and related equipment where the design method is "Strain based", such as ISO 13628-7, to provide a better load capacity model, the above statement does not apply.
and
Both API 6A “Yield based” and ISO 13628-7 “Strain based” design approaches as valid, as long as the application of hardware is valid for the calculation method selected.

## F.12.2 Section 2 Amendments, Revision 8.1, December, 2012

**Equipment, Quality Control and Qualification**

**Section 2.4.2.1** Qualification of Contractors

Replacement of the last sentence: "Records of any such evaluation must be retained in the location records for reference, and reviewed at regular intervals with updates as needed to reflect any changes in personnel or facilities.
by, the sentence:
"Ownership of these evaluations must be taken by the Testing location Management. An Audit/Inspection report should be entered into Quest and any remedial actions closed out. Records of any such evaluation must be retained in the location records for reference. For locations where permanent contracts exist, an audit/inspection should be conducted every year or when changes in key personnel or facilities could affect working practices."

## *F.12.3* Section 3 Amendments, Revision 8.1, December, 2012

**Well Integrity**

**Section 3.2.2.** Additional Design and Planning considerations for Coiled Tubing Operations
Added at the end of the 8th bullet of the sentence " The currently established SenTREE ball valve cutting capabilities are available at InTouch Content ID 5705582 (SenTREE 3) and InTouch Content ID 4129312 (SenTREE 7)."

**Section 3.2.3**. Additional Design and Planning considerations for CIRP Operations:
Insertion in the first bullet, of "see InTouch Content ID 3319326, section E".

**Creation of Section 3.2.6 Selection of Well Barrier Working Pressure**.

## *F.12.4* Section 4 Amendments, Revision 8.1, December, 2012

**Surface Equipment**

Completely deletion of sections **4.3.2** thru to **4.3.2.5**.

**Section 4.4.3.2 Kill Line**
Replacement of the para: "Consideration/recommendation should be given to the use of a check valve between the Kill Line hose or piping and the Flowhead or Production Tree." by the new para:
It is mandatory to use a check valve between the Kill Line hose or piping and the Flowhead or Production Tree. The check valve must be mounted as close as possible to the Flowhead or Production Tree. The lock open type check valve can be used in case it is required to bleed tubing pressure via the kill line. (eg.

pressure testing, ProFire or eFire cycling, , etc...). The lock open check valve must be returned to the checked position as soon as possible especially during well flowing.

**Section 4.4.9 Pipework**
Added of the Note:
**Note:** Flowback of acid can also be aggressive for well test piping elastomer lip seals if not properly chosen to resist acid and any additives that may be present. Careful seal selection is required to ensure all conditions can be met.

Section **4.4.9.2 Tie-Down or Line Securing Systems**
Adding of text at the end of figure 4.1 Polyester Roundsling Application Chart: "If the outside temperature is expected to go between 32 degF (0 degC) down to -40 degF (-40 degC) then the rounslings should be perfectly dry otherwise ice may appear and can act as cutting and abrasive instrument which can cause internal damage to the sling and therefore reduce dramatically its performance as restraint system."

**Section 4.4.11 API Threads**
Insertion of 2 links toward section **2.5.1** and **B.3**.

**Section 4.4.13.1 Chemical Injection Lines**
Added of the paragraph: "The pressure rating of liners depends on size, material and thickness and should be manufactured as per industry standards ASME, ASTM and API . Liner's pressure rating should be easily identified by proper marking. Refer to Section 7.7.3 for additional rules regarding liners."

Section **4.4.15.1 Tanks**
Adding of a "CAUTION" at the end of the section.

Section **4.7.1 Major Re-Certification** .
Deletion of the Note at the end of the section.
Creation of a new section **4.7.1.1 Equipment Obsolescence** .

## F.12.5 Section 5 Amendments, Revision 8.1, December, 2012

**Subsea Safety Equipment**

Complete deletion of sections **5.4.1** thru to **5.4.1.5**.

**Section 5.8.1 $H_2$S Operations**, adding of a Footnote inside the Note:

"Total Pressure is the maximum pressure the equipment will be subject to, it will be WHP for surface equipment or maximum anticipated internal pressure at the tool level for downhole sampling, DST or Subsea equipment."

## F.12.6 Section 6 Amendments, Revision 8.1, December, 2012

**Downhole Equipment**

Complete deletion of sections **6.3.1.** thru to **6.3.1.4**.

**Section 6.6.1 $H_2S$ Operations for DST** , adding of a Footnote inside the Note: "Total Pressure is the maximum pressure the equipment will be subject to, it will be WHP for surface equipment or maximum anticipated internal pressure at the tool level for downhole sampling, DST or Subsea equipment."
Deletion of the sentence: "(ppm may be expressed in volume percent; 10 ppm = 0.001%)."

## F.12.7 Section 7 Amendments, Revision 8.1, December, 2012

**Sampling and Analysis Pressure Equipment**

**Section 7.9.2 $H_2S$ Operations**, adding of a Footnote inside the Note: "Total Pressure is the maximum pressure the equipment will be subject to, it will be WHP for surface equipment or maximum anticipated internal pressure at the tool level for downhole sampling, DST or Subsea equipment."
Deletion of the sentence: "(ppm may be expressed in volume percent; 10 ppm = 0.001%)."

## F.12.8 Section 8 Amendments, Revision 8.1, December, 2012

In **Section 8.4**, in the 3$^{rd}$ paragraph, deletion of the sentence: "Only use water guns when the specific gravity of the fluid surrounding the guns is equal to or greater than 1 SG without the presence of gas."
Deletion of the 4$^{th}$ paragraph "Whenever the perforating operating environment exceeds 80% ..... (i.e., employ critical well procedures)."

**Section 8.5.1.4 Wellhead Pressure**

Change in Note which becomes: "It is vital for Well Integrity that only trained personnel and verified competent by the TCP Engineer or Technician, operate the CIRP deployment stack."

Creation of a new **section 8.8.1.4 Coil Tubing Certification**.
Old section 8.8.1.4 becomes 8.1.1.5 and so on..

## F.12.9 Section 9 Amendments, Revision 8.1, December, 2012

**Testing Services Personnel Qualification and Administration**

Creation of the a new section **9.2 Well Integrity Certification** which was the old **section 9.1.10**.
Creation of a New Section **9.1.10 Deepwater Certification**

Creation of a new section **9.1.11 TCP Pressure Certification**.

## F.12.10 Appendix B Amendments, Revision 8.1, December, 2012

**Surface Well Testing Pipework and Flexible**

In section **B.2.3.2, B.2.3.3** and **B.2.3.4**, adding of the text:
"As per API RECOMMENDED PRACTICE 7HU1 and IADC alerts," at the beginning of each first paragraph.

In section **B.2.3.11 Procurement of Pipework Crossovers, Replacement Piping, and Flexible Hoses** , adding of the paragraph:
"All pressure-containing and pressure-controlling equipment including crossovers and surface piping shall be purchased exclusively through Schlumberger Product Centres." which becomes the first paragraph of the section.

Added in Figure B.3 Schlumberger Rating for "Grayloc" Clamp Connector Pipework, of the last remark below the figure:
" *** Some C25 Grayloc piping 15kpsi WP previously sold by SRPC does not correspond to the C25 Piping described in this table but have the following characteristics: Nominal Size 3", Pipe OD: 3.500", Nominal Wall Thickness: 0.600", Minimum Wall Thickness: 0.530". This piping can still be used but under the following criteria: A valid Annual Survey, minimum wall thickness => 0.530" and an approved Exemption by Geomarket in Quest."
**Change in Figures B1, B3 and B4, line A333 gr 6**, of Temperature becomes:

"A333 gr 6: -20degF to 350 degF (-29 degC to 177 degC) as standard, or -50 DegF to 350 DegF (**-45.5 DegC** to 177 DegC) subject to Charpy Impact Test at time of manufacture.

Section **B.2.4.9 API Specification 6A Flanges and Spools**, modification of the 5th paragraph which becomes:
"Due to this restriction, COFLEXIP hoses with API flanges should always be fitted with a X-Over/Saver Sub to Hammer Union or Grayloc connectors."

## *F.12.11* Appendix C Amendments, Revision 8.1, December, 2012

**Regional Manufacturing, and Local Remanufacturing and Repair of Pressure Containing or Controlling Equipment**

Creation of a new section **C.1.2.2 Maintenance of Downhole or Below Flowhead Crossover**
Old Section C.1.2.2 Crossover Redressing and Re-cuts becomes C.1.2.3 and so on...

# *F.13* Revision 8.2, January, 2014, Release Notes

Version 8.2 of the Pressure Operations Manual represents a "minor" rework of the standard with significant changes or additions in most sections.

A summary of the main changes are as follows:

POM Feedbacks, and POM related InTouch Tickets and Lessons learnt submitted since the release of POM V8.1 have been reviewed and integrated, or revisions made to make the requirements clearer.

## *F.13.1* Section 1 Amendments, Revision 8.2, January, 2014

Section **1.1 Scope** at the end of the section, adding of this text:
"The Testing Services POM does not apply to some of the basic Production Testing Operations. For those operations, the Production Testing Services Standard is available on InTouch Content ID 6255521 , and is applicable only for Production Testing operations which are conducted in a specific domain of application and only where all the following conditions are met: Land rigless environment, Permanent X-mas tree, Well has already flown in the past, Known and stable operating conditions (including: pressure, temperature, rates, fluid composition and fluid properties), Well head pressure is less than 9,500 psi,

Well head temperature is less than 121 degC, Production line pressure is less than 1440 psi, $H_2S$ concentration is less than 10%, Liquid flow rates are less than 8,000 bbl/d and Gas flow rates are less than 30 mmscf/d. For all other operations, the POM applies."

Section **1.1 Scope, 2nd paragraph**, modification of the sentence:
The Testing Services Pressure Operations Manual (POM), Revision 8.2, released -actual release date: January 31st , 2014 is the internal standard in terms of pressure regulation and supersedes any previous Pressure Operations Manual.

Last paragraph of the section is as follows:
The Testing Services POM does not apply to the basic production Testing operations covered by the "Production Testing Services Standard for Land/Rigless Operations" available on InTouch Content ID 6255521, and is applicable only for Production Testing operations which are conducted in a specific domain of application and only where all the following conditions are met:
- Land rig less environment,
- Permanent X-mas tree,
- Well has already flowed in the past,
- Known and stable operating conditions (including: pressure, temperature, rates, fluid composition and fluid properties),
- Well head pressure is less than 9,500 psi,
- Well head temperature is less than 121 degC [249.8 degF],
- Production line pressure is less than 1440 psi,
- H2S concentration is less than 10%,
- Liquid flow rates are less than 8,000 bbl/d and Gas flow rates are less than 30 mmscf/d.

For all other operations, the POM applies."

Section **1.6.3 Test Pressure (TP)** Adding of following paragraphs:
"For downhole tools, Test Pressure is generally equal to Working Pressure." at end of paragraph.
and a new last paragraph:
"This last comment is not true for sampling tools, which return to surface under pressure. Therefore they become effectively Surface Equipment before the samples are transferred into shipping cylinders."
For downhole tools, Test Pressure is equal to Working Pressure except for sampling tools which return to surface under pressure, the Test Pressure for these sampling tools is 1.5 times working pressure

Section **1.9.1 Type of Pressures Tests**, Adding of 2 paragraphs:
There are different types of "pressure tests"
and at the end of the section:

”RSA laboratory pressure tests, performed in the laboratory require a job-specific approved HARC to be in place. Adequate warnings must be posted in the area where the equipment is being tested, and all unnecessary personnel must evacuate the area. “Lines of fire” must be identified (valves, pressure ports, fittings) and personnel carrying out the test must stand clear of them.”

In section **1.9.3 Pressure Testing with Inert Gas: (Gas Test)**

Adding of a paragraph at the end of the first bullet list: “Certain fluid and rock analysis equipment, from which pressure test liquid cannot be completely drained after the test.”

The “Danger" note from bottom of page: "When bleeding off the pressure after completing a pressure test..." has been moved without indent to previous page 1-20, after all the bullet points "General rules to observer if testing with gas". At end of this "Danger" note, adding of the following: "When the volume of the chamber exposed to Nitrogen pressure is very small making this bleed-off procedure difficult to observe (e.g. function/pressure testing DST tools atmospheric chambers), the Nitrogen pressure should be bled off as slowly as practical. If elastomers are to be exposed to gas at high pressure (above 1100 psi) more than 20 min. the bleed off schedules shall be respected.”

In all Section 1, deletion of the Word RITE.Net replaced by the word RITE.

## F.13.2 Section 2 Amendments, Revision 8.2, January, 2014

In all Section 2, deletion of the word RITE.Net, replaced by the word RITE.

Section **2.3.1 Asset Certification and Traceability**, at the beginning of the section, the sentence as follows:
All new equipment shall be delivered to the field or laboratories with their associated Quality Files. Quality Files will include any or all of the following:

Section **2.3.2 Rented Equipment**, replace current section as follows:
Well Barrier Elements as defined in Chapter3: Well Integrity (e.g. Flowheads, DST tools, Subsea tools, below flowhead/DST/Subsea crossovers etc...) must exclusively be supplied by Schlumberger; it is NOT permitted to rent any well barrier elements. Any deviation from this rule will require an exemption to be approved only by Testing Services Headquarter.
Pressure Containing or Pressure Controlling equipment not defined as Well Barrier Elements (e.g. Steam Exchangers, Tanks…) may be rented provided the rental company has been positively assessed as defined in Section 2.3.2.1.
The rental company shall provide a complete Quality File with Type Approval (TA) or Design Verification Review (DVR), Certificate of Conformity (COC) and Data Book similarly to the Quality File provided by the Product Center

for Schlumberger equipment of the same type. The Table of Content of an equivalent Schlumberger Asset Quality File can be used as a check list to ensure completeness of the rented equipment Quality File.
Other equipment not Pressure Containing/Controlling related (e.g. Compressors) may also be rented assuming the rental equipment meet the same standards applicable to Schlumberger equipment (Traceability, Lifting certifications, Equipment age, etc...). The rental agency shall supply an in-house certificate-guaranteeing conformance to the standards, showing results of latest tests and various inspections. Integrity and operational test shall be not older than three months at the time of equipment delivery to Schlumberger and issued at the same time as the equipment.

New Section **2.3.2.1 Rental Equipment Supplier Management**:
Rental equipment supplier shall be approved by Supply Chain.

For the rental of Pressure Containing or Pressure Controlling Equipment, the Area Equipment Assurance functions shall perform a technical evaluation of the rented product and assess the supplier maintenance and management process. This evaluation process shall be performed either by competent Area staff, certified third party or alternatively with the assistance of the Product Centre through an InTouch ticket followed by an RFQ.

For the rental of other equipment (e.g. Compressors), the Geomarkets shall perform a similar technical evaluation of the rented product and assessed the supplier related maintenance and management process.

Section **2.3.3 Client Supplied Equipment**, Figure 2–1 Client Owned have be changed.

Section **2.4.2 Asset Certification**, Adding of a bullet: “It is green tagged and has been suitably maintained and left ready for use, with FIT, TRIM and all required calibrations completed and current, and entered into RITE.”

**Section 2.4.3 Replacement of Parts or Equipment Repair /Re-Manufacturing,**
Replacement of the first sentence by:
”When structural parts which are of a pressure retaining or load bearing nature (For example housings, bodies, etc.) are repaired or replaced the asset loses its certification status and shall require witnessed testing by a certifying agency. This re-certification includes post-repair witness of the proof pressure test along with other functional and operational tests part of the initial asset FAT procedure.”

**Section 2.4.3 Replacement of Parts or Equipment Repair / Re-Manufacturing**, ad a 'note' at end of this section as follows:

**Note**

Hardware or Firmware modification to Safety Equipment and/or Pressure controlling/Pressure Containing equipment such as ESD, PRV's, etc... is forbidden unless approved by the Product Center responsible for that equipment. Approval can be via Modification Recap (for Fleet), via an RFQ or via InTouch (for individual asset).

Section **2.4.4 Reception control**, modification of the 4th paragraph which becomes:
The Quality file shall also be checked at the time of equipment reception, and any non-conformity reported to the supplier. The date of the initial certification pressure test shall be verified and entered in RITE.Net (if not already entered by the Product Center) to provide the basis for the due dates of futures Q-Checks and Certifications. The commissioned date entered in RITE.Net should be the same as the FAT dates indicated on the Quality Files.

Section **2.4.8 Equipment Disposal**, additional comment: "The equipment shall be disposed of responsibly, following the requirements outlined in the local waste management plan, and using only Schlumberger approved disposal vendors."

## F.13.3 Section 3 Amendments, Revision 8.2, January, 2014

In all section 3, deletion of the word RITE.Net, replaced by the word RITE.

## F.13.4 Section 4 Amendments, Revision 8.2, January, 2014

Section **4.2.1 General Standards**, first bullet point is replaced by this one:
"- API Specification 6A for Flowheads, Surface Safety Valves, Choke Manifolds upstream heat exchangers chokes. The API 6A introduced the introduced the "Product Specification Level" (PSL) concept with the publication of API 6A, 15th Edition, effective April 1, 1986. The PSL system applies a tiered level of material qualification testing and non-destructive testing to equipment as specified by the user/buyer and allows reference to standard procedures to apply continuously higher standards for higher risk equipment applications. PSL's have number designations, as PSL 1, PSL 2, PSL 3, PSL 3G, and PSL 4, representing a progression from lowest risk to highest risk applications."

**Section 4.2.2 General Testing Services Specifications** paragraph which begin by: "The 3G is a recently introduced API 6A / ISO 10423:2009" is replaced by this Note:

**Note**

Although PSL-3 has proved, by means of an extensive track record, to be sufficient for Testing Services operations, it has been decided to move to PSL-3G for newly manufactured Flowheads as they are designated as being a Well Barrier Element (Refer to POM Section 3: Well Integrity for the detailed explanation of the term "Well Barrier Element" and related requirements, however the only Surface Testing equipment which is classed as a Well Barrier Element is the Flowhead). Certification of Testing Pressure Equipment to PSL 3G requires at the time of manufacture a pressure test to WP with inert gas. Should the location requires to maintain PSL-3G level at Major re-certification, this test will have to be performed again (this is not a customer requirement for most of the Testing Operations). Testing Pressure Equipment built following API 6A specification PSL 3 may be upgraded to PSL 3G under specific conditions as detailed on the InTouch content "Frequently Asked Questions on API Spec 6A - PSL 3G" - paste InTouch Content ID 6262090.

Section **4.2.2 General Testing Services Specifications**
Removing the wording "second edition 2009" under point "2) H2S Service" and "3) Hostile Service"

Section **4.4.2 Type of valves for Cat 1 eqt, table 4-5** replace the current $SS_o$ description in Legend of the table by the following:
$SS_o$ = Subsurface Valve (EZ valve, SCSSV, etc..) not mandatory (except for floating rigs where a SubSurface Test Tree is needed).

Section **4.4.8.1: PRV/PSV Operation**, create this new section (old section 4.4.8.1 becomes 4.4.8.2).
Replacement of the sentence: “An inline PRV manual....for PRV type selection” by new sentence:
.
”For detailed information, please refer to the Balanced Bellow PRV operating and maintenance manual In Touch Content 6071992 and the Pilot Operated PRV operating and maintenance manual InTouch Content 5859575.”

Section **4.7.1 Major Re-Certification**, added link to Appendix B at this sentence:
* For detailed instructions, refer to ...

Section **4.4.17.1 Hazardous Areas** all text replaced as follows:
A new zoning guideline based on API-505 using engineering & operational judgement, but also considering ventilation, is available on the latest Field Operating Handbook released under the InTouch Content ID 3916699 and must be followed accordingly.

The installation environment must be analyzed and classified as part of the risk assessment procedure. The wellsite is classified into zones, based on the likelyhood of ignitable concentrations of flammable gas or vapor under normal operating conditions.

The rig area classification must be discussed between Schlumberger and the rig supervisor during the site rig visit and prior to issuing the Surface Equipment Layout drawings. It is the rig supervisor's responsibility to provide zone classification depending on rig equipment, air intakes, living quarters, etc.

Table no 4–6 provides values derived from the API standard that can be used as references for zoning classification under normal operating conditions. Inserted at end of this paragraph the table 1-11 from the SWT FOH (InTouch Content ID 3916699).

Section **4.4.17.2 Non-Hazardous Area**, deletion of the end of paragraph starting from "For example, if an area of the wellsite is......" until the end, deleting also of the note.

Section **4.4.18 Fire Risk**, add at bottom of section a 'Danger' note as follows: Danger

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**Danger**

Potential Severity: Catastrophic
Potential Loss: Assets, Personnel
Hazard Category: Fire flammable

Whenever performing flaring operations including on land jobs, a reliable and remotely operated pilot ignition system MUST BE installed and fully functional.

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Section **4.4.15 Tanks**, modification of the two first sentences on third paragraph as follows:
Gas or vent lines from any tanks must be run clear of the well test area. If the gas is not flared but cold vented, then a wind sock must be provided in clear view of the well test area so that the direction of the wind can be monitored.

Section **4.4.15.2 Gauge Tanks**, add of the following sentence before the Note: ”Due to the possible introduction of oxygen into the Gauge Tanks which highly increases the risk of combustion reactions, Gauge Tanks vent lines must NOT be connected to a gas flare. Any deviation from this rule will require to have an exemption approved by Testing Services Headquarter. The detonation flame arrestors fitted on the gauge tanks are only for mitigation in case the cold vented is accidently flared. Although the Gauge Tanks have these detonation flame arresters permanently fitted on the tank roofs, whenever vent lines are to be extended, the optional flame end-arresters kits connected at the end of the vent hoses must be used to ensure low flame velocities protection by complying with the detonation flame arrester installation rule (distance from potential ignition point less than 50 times vent line diameter)."

## F.13.5 Section 5 Amendments, Revision 8.2, January, 2014

In all section 5, deletion of the Word RITE.Net, replaced by the word RITE.

Section **5.1.1 Test Pressure** first sentence after the table 5-1 must be modified as follows:
"Pressure Testing at major survey of assets in accordance with original FAT procedure and pressure test values are to be done as detailed in GeMS document 100282338: with hyperlink
http://docs.gems.slb.com/ENG/SPT_SUBSEA/100282338/100282338-AE.pdf

Section **5.9.3 Five Year Major Survey**
In Second paragraph modification of the sentence as follows:
Procedures for these tests are regulated by API 6A code and are detailed in document 100282338, which is included in the operations and maintenance manuals.
Adding of link to GeMs document:
http://docs.gems.slb.com/ENG/SPT_SUBSEA/100282338/100282338-AE.pdf.

Section **5.9.5. Major Repairs/Remanufacture**,
Replacement of the sentence: "When structural parts which are of a pressure retaining or load bearing nature (For example housings, bodies, etc.) are replaced, the equipment loses its certification status and shall be certified again by a certifying agency."
by the following sentence: "When structural parts which are of a pressure retaining or load bearing nature (For example housings, bodies, etc.) are repaired or replaced the asset loses its certification status and shall require witnessed testing by a certifying agency. This re-certification includes post-repair witness of the proof pressure test along with other functional and operational tests typically found in the asset FAT procedure".

Section **5.10.2 Rented Equipment**, the content is replaced by:
"Due to the primary safety function of Subsea safety equipment, renting or operating equipment supplied by a third party is not recommended. If unavoidable, Subsea testing equipment accessories may be rented from a rental agency if the policy in Section 2.3.2: Rented Equipment".

## F.13.6 Section 6 Amendments, Revision 8.2, January, 2014

Section 6, replacement in all section of the word RITE.Net by the word RITE.

**Section 6.3.2 Pressure Barrieres for DST, table 6-1** replace the current $SS_o$ description in legend of the table by the following:
$SS_o$ = Subsurface Valve (EZ valve, SCSSV, etc..) not mandatory (except for floating rigs where a SubSurface Test Tree is needed).

Section **6.5 Pressure Testing**, adding of the following text at the send of this section: "For the purpose of surface tests, DST tools with 3 –1/2 IF connections have a tool joint groove where an O-ring can be installed. The purpose of the O-ring in the 3-1/2 IF tool joint groove is to facilitate the surface test without torquing the test caps up to its optimum torque value. The design intent of the O-ring seal is NOT to assist in the seal of the connection during downhole conditions but it is the purpose of the metal to metal (MTM) face seal of the tool joint. Moving the "downhole seal" from the MTM face seal to the O-ring seal will change the hydraulic loading of the connection, and under high pressure situations may result in a catastrophic mechanical overload, therefore all O-rings shall be removed from the 3-1/2 IF tool joint groovebefore tools are run in holes."

## *F.13.7* Section 7 Amendments, Revision 8.2, January, 2014

In all section 7, replacement of the word RITE.Net by the word RITE.

Section **7 Sampling and Analysis Pressure Equipment**, Replacement of the first paragraph by:
"This section covers guidelines for the use of Reservoir Sampling and Analysis Pressure Equipment. All equipment used for capturing samples, both downhole and surface, are covered under this definition, as well as all well site and laboratory fluids and rock analysis equipment that holds pressure, including PVT pressure cells, core holders, piston accumulators, tri-axial/poly-axial load cells etc. Equipment is categorized based upon definitions described below."

In the same section replacement of Category 1, by:
"**Category 1.1**
Surface equipment designed to handle only internal pressure (eg sample receptacles, Laboratory PVT cells, PVT-XP Cell, Core Holders, Load Cells etc)".

Section **7.1 Overview**, first sentence is replaced by:
"All fluid sampling RSA pressure containing equipment used by Schlumberger shall be pressure rated. The rating is expressed as a Working Pressure (WP) and a Test Pressure (TP)."

Other paragraphs become:
"Schlumberger Product Development normally assigns Working and Test Pressure ratings unless designed by a Schlumberger approved third party equipment manufacturer. Occasionally Oilphase Product Center, DBR

Technology Center, TTK Technology Center or Wireline Product Centers will assign a lower rating to meet more stringent requirements. In all cases the Schlumberger-assigned Working Pressure rating (WP) must be used."

"It is forbidden to submit any piece of sampling RSA equipment to a differential pressure higher than its WP rating during operations."

"The Working Pressure rating is valid in a given temperature range. Depending on the equipment type and its specifications, a different type of equipment shall be used for temperatures outside the range specified. If the given equipment is to be used outside the specified temperature range, the Working Pressure rating will be modified. This modification to WP shall be qualified via the Oilphase Product Center, DBR Technology Center, TTK Technology Center or Wireline Product Center."

Section **7.1.1 Test Pressure**

First para is modified: "The latest RITE File Code Certification and Maintenance Requirements and the Operating/Maintenance Manuals/Procedures within InTouchSupport.com must be reviewed and understood prior to commencing any pressure testing of any fluid sampling and analysis RSA pressure retaining equipment."

The word TPED becomes: PED.

Section **7.1.2.** becomes: 7.1.2 Test Pressure of Laboratory Fluid Analysis Equipment
At the end of the section adding of the sentence: "Any TTK legacy equipment must be marked with a Working Pressure and Test Pressure".

Section 7.2.2 becomes: **7.2.2. General RSA Specifications**
Items 7 and 8 are modified.

Section **7.2.5** General Rock Laboratory Equipment Standards and Specifications, becomes **7.2.6**.

Section **7.2.6** Job Design and Well Integrity, becomes **7.2.7.**

Section **7.3.1** becomes: 7.3.1 Reservoir Sampling and Analysis Equipment General Rules

Section **7.3.2 Selection of Equipment Working Pressure**,
1. Becomes: . RSA Downhole Sampling Tools

2. becomes: RSA Surface Sampling Equipment
3. becomes: RSA Sample Receptacles
4. becomes: MRSS Sample Bottles (MSB)

5. becomes: RSA PVT Cells
7. becomes: Sample Bottles Manufactured in DBR Technology Center

Section **7.3.2, part3 Conventional Sample Bottle (CSB)**, replacement of the last sentence "Once the sample has been taken it is standard practice to introduce a 10% of sample volume gas cap to allow the sample to expand due to temperature variations and to comply with transportation regulations." **by** "Once the sample has been taken, it is standard practice to introduce a 10% of sample chamber volume gas cap to allow the sample to expand due to temperature variations and to comply with transportation regulations."

Section 7.5 Oilphase is replaced by RSA.

Section 7.5.4 DBR is replaced by RSA.

Section 7.6.1 Connection of Pressure Equipment to SchlumbergerSampling Tools & Receptacles

Section **7.6.2 Connection of Pressure Equipment to Third Party Sampling Tools & Receptacles**
Adding of the following sentence at the end of the section: “A Wellsite Sample Tansfer Operations compliance checklist is available on InTouch content #5384961 and shall be used by Schlumberger personnel to verify POM compliance with respect to any wellsite sample handling, heating, transfer and bleeddown operations involving reservoir fluid samples contained within any Schlumberger, customer or 3$^{rd}$ Party sampling tools, bottles and receptacles”.

New Section **7.6.7.1 Wellsite and Field Location Sample Conditioning**

Section **7.6.10** adding at the end of the section, the sentence “For the specific case of high pressure gas/gas condensate blow downs, refer to InTouch Best Practice 6211844 which details extra specific instructions for the safe blow down of these samples.”

Section **7.7 Sampling and Analysis Manifolds, Hoses, Liners, Fittings and Connectors**, adding of two para:
”Swagelok fittings come in a large variety and should be chosen carefully. When selecting a product, the total system design must be considered to ensure safe, trouble free performance. Function, material compatibility, adequate ratings, proper installation, flow rate, operation, and maintenance must be taken into consideration and applied correctly. Only appropriately trained personnel should make-up compression fittings (e.g. Swagelok training).

Teflon tape or thread sealant is used only on NPT connections. In rare cases it may be forbidden by the product operating or maintenance manual.”

Section **7.11.3 Rented Sampling Equipment** is replaced by the following text: "Renting Sampling equipment such as sample bottles is strongly discouraged however they may be rented from a rental agency if the policy in Section 2.3.2: Rented Equipment is respected."

## *F.13.8* Section 9, Amendments, Revision 8.2, January, 2014

In all section 9, replacement of the word RITE.Net by the word RITE.

Section **9.1.10 Deepwater Certification**
Replace the sentence of the 2$^{nd}$ paragraph by: "More information on the Deep Water and Special Projects (DW&SP) program itself can be found under the Schlumberger DeepWater Hub page available at the following address: http://www.hub.slb.com/display/index.do?id=id3294050".

## *F.13.9* Appendix B, Amendments, Revision 8.2, January, 2014

**Design Standard for New Pipework**

In all Appendix B, replacement of the word RITE.Net by the word RITE.

Added in section section **B.2.2.6 Thickness Calculations for Pipework Crossovers, Tees, and Laterals etc**.

Added of the sentence "In the event that OD's are not available from Quality Files, they will have to be measured with a caliper. Measurements will be taken from each end of the crossover where OD's are constant."

Correction in section **B.2.4.7 Grayloc Connectors** of figure B-15: API Specification 6A Flanges and Ring joints there is a typo error for API-BX 15000lb BX gasket:
Under the line for the 2-9/16 replace the "BX-163" by the correct " BX-153" Under the line for the 3-1/16 replace the "BX-164" by the correct " BX-154".

## *F.13.10* Appendix C, Amendments, Revision 8.2, January, 2014

In all Appendix C, the word RITE.Net is replace by the word RITE.

## F.13.11 Appendix E, Amendments, Revision 8.2, January, 2014

Modification in Appendix E.
Section E.3 Scope
Section E.4.1 Key Definitions

Section E.4.2 Responsibility

Section E.3.4.7 RSA Facility Exhaust and Ventilation Systems

Section E.4.3.1 Operational Areas in Reservoir Sampling and Analysis Locations

Section E.4.3.2 General

Section E.4.3.4 Safety Equipment

Section E.4.3.6 $H_2S$ Detection Systems

Section E.4.4.1 Hazard Analysis and Risk Control (HARC)

Section E.4.4.3 Operational considerations for Reservoir Sampling and Analysis operations for samples with $H_2S$ concentrations <50 ppm

Section E.4.4.5 Emergency Response

## F.13.12 Appendix F, Amendments, Revision 8.2, January, 2014

Adding of update v8.2, January 2014.

# F.14 Revision 8.3, January, 2015, Release Notes

Version 8.3 of the Pressure Operations Manual represents a “minor” rework of the standard with significant changes or additions in most sections.

A summary of the main changes are as follows:

POM Feedbacks, and POM related InTouch Tickets and Lessons learnt submitted since the release of POM V8.2 have been reviewed and integrated, or revisions made to make the requirements clearer.

Throughout the POM, the version number and the date have been removed from the revision history subsection at the end of the sections and appendices. The release date and version number are still present in the information given on the left hand side of each page, along with the EDMS UID and the InTouch Content number.

## F.14.1 Section 1 Amendments, Revision 8.3, January, 2015

Section **1.3 Abbreviations** Removed the entry for OPPC (Oilphase Product Centre).

Section **1.6.3 Test Pressure (TP)**Added at the end of this section For SubSea Landing String tools, Test Pressure is equal to 1.2 times the working pressure (WP), unless a major pressure containing or load bearing component has been repaired, welded or replaced since last Major Survey or FAT in which case a body pressure test according to the design will be required at Test Pressure normally 1.5 times the working pressure (WP).

Section **1.9.1 Type of Pressures Tests** Added at the beginning of this section: "All pressure test operations to be carried out with Permit To Work in place and Pre-Job Safety meeting prior to proceeding.

## F.14.2 Section 2 Amendments, Revision 8.3, January, 2015

Section **2.3 Procurement** In the first note, changed “OPPC Rapid Response Crossover group” to “RTST Rapid Response Crossover group”.

Section **2.5.1.4 Certification (Major Survey)** Changed “A Major Re-Certification consists of at least:” to “Major survey requirements would typically include the following (but for detailed Major Survey requirements, refer to the relevant discipline section of this POM).”

Section **2.5.6.3 Ultrasonic** Changed “performed in accordance with procedures specified in ASME Boiler and pressure Vessel Code, Section V, Article 5” to “performed in accordance with the design codes of the given tool”.

Section **2.5.6.4 Magnetic Particle or Liquid Penetrant Inspection** Changed “It shall also be performed to reveal cracks and flaws after heat treatment and final machining operations” to “It shall also be performed to reveal cracks and flaws after heat treatment or final machining operations, and be performed in accordance to the design codes of the given tool”.

## F.14.3 Section 3 Amendments, Revision 8.3, January, 2015

Section **3.2 Job Design, and Planning Well Barriers** Corrected a spelling error in several places, from “specifc” to “specific”.

Section **3.2.2 Additional Design and Planning considerations for Coiled Tubing Operations** Changed “Well Services QHSE Standard 22: Coiled Tubing Operations and to retired InTouch Content ID 3313710” to “Well Intervention QHSE Standard 02: Coiled Tubing Operations, InTouch Content ID 5884296”.

Section **3.2.6.1 Maximum Potential Wellhead Pressure or Maximum Potential Pressure**Deleted the following “On subsea jobs where a SenTREE is run in the string, the depth of the water, and also the density of the potential fluids in the test string, will affect the hydrostatic pressure acting on top of the valve. Therefore the pressure which would have to be applied at surface in order to bullhead through a closed SenTREE valve will vary from job to job and will have to be estimated at the time of job design.”

Section **3.2.3 Additional Design and Planning considerations for CIRP Operations** Changed “Well Services QHSE Standard 22: Coiled Tubing Operations and to retired InTouch Content ID 3313710” to “Well Intervention QHSE Standard 02: Coiled Tubing Operations, InTouch Content ID 5884296”.

## F.14.4 Section 4 Amendments, Revision 8.3, January, 2015

Section **4.4.4 Emergency Shutdown System** Changed “The ESD consists of a remotely actuated valve on the flowhead or a stand-alone remotely actuated isolation valve on the wellhead” to “The ESD system (pneumatic or electric) consists of a remotely actuated valve on the flowhead or a stand-alone remotely actuated isolation valve on the wellhead.”

Section **4.4.9.2 Relief Valve Discharge Piping** This section has been promoted by one level and has been numbered. As a consequence, the numbering of the following section has changed.

Section **4.4.12 Fittings** Added a note to the table, “Some specific clients (Shell, for instance) mandate NPT fittings bigger than 1/2" being kept for WP only up to 285psi; this needs to be considered carefully during the job preparation and discussed with the client (ie: separator uses 3/4" NPT port)”.

Section **4.4.13.1 Chemical Injection Lines** Changed “Chemical Injection connections to pipework or equipment must have a maximum nominal bore of 1/2 in. and shall include a close-coupled check valve. Associated liners or piping should be stainless steel tubing or premium material compatible, with the chemical injected." to "Chemical Injection connections to pipework or equipment must have a maximum nominal bore of 1/2 in. If two isolation valves are used, one check valve shall be included. If only a single isolation valve is used then **either** a close-coupled check valve **or** two check valves shall be included. Associated liners or piping should be stainless steel tubing or premium material compatible with the chemical injected."

Section **4.4.15.2 Gauge Tanks** Inserted the following paragraph. "It is also strongly recommended to install a flow restrictor upstream of the gauge tank and downstream of the oil manifold. This will protect the tank in the event of gas blow by, and help maintain a constant oil line back pressure thus making separator level control easier."

Section **4.4.16 Flame Arresters** Changed "a distance which is at least 50 times the nominal diameter of the line" to "a distance which is more than 50 times the nominal diameter of the line".

Changed "low flame velocities" to "low flame front velocities".

Section **4.4.19 Elastomers** This is a new section.

Section **4.6.5 Solids Production** Changed "Please refer to InTouch Content ID 4272030 and InTouch Content ID 2045743 as examples" to "Please refer to InTouch Content ID 5958396 (hyperlink) for selection and guidelines".

## *F.14.5* Section 5 Amendments, Revision 8.3, January, 2015

Section **5.1.1 Test Pressure Table 5-1** Changed all occurrences of "1.5 x Max WP" to "1.2 x WP" and removed all other occurrences of "Max" in the table.

## *F.14.6* Section 6 Amendments, Revision 8.3, January, 2015

Section **6.2.2.2 Design Safety Factors for Downhole Equipment** Changed "All Drill Stem Testing equipment shall have a minimum pressure rating (WP) of 10,000 psi" to "All Drill Stem Testing equipment shall have a minimum pressure rating (WP) of 10,000 psi at the exception of PIPK-DJ which has a lower Working Pressure (refer to the PIPK-DJ documentation)."

## *F.14.7* Section 7 Amendments, Revision 8.3, January, 2015

Section **7 Reservoir Sampling and Analysis Equipment** Changed "MWP" and "MAOWP" to "WP".

Section **7.3.2 Selection of Equipment Working Pressure** In the subsection concerning RSA PVT Cells, changed “Equipment must not be subjected to operating pressures in excess of Maximum Allowable Working Pressure (MAOWP) at any time” to “Equipment must not be subjected to operating pressures in excess of WP at any time, except during certifying 'test pressure' scenarios every 5 years. When working at pressures close to WP, it is important to set a slightly lower pressure for transfer and other sample tests than the WP. This ensures that the WP is never exceeded during the operation”.

Section **7.3.3 Pressure Relief Devices** Changed “Replacement relief valves can be ordered from OPPC via SWPS” to “Replacement relief valves can be ordered via SWPS”.

Section **7.6.7 Heating of Sampling Equipment and Sample Receptacles (Sample Conditioning)**Changed “approved heating temperature limits of OPPC” to “approved heating temperature limits of Testing Services”.

Subsection **Extended Heated Storage in an Oven** In the warning, changed “approved heating temperature limits of OPPC” to “approved heating temperature limits of Testing Services”.

Section **7.9.1.1 OPPC and DBR Product Metallurgy Limitations** Section heading changed from “OPPC and DBR Product Metallurgy Limitations” to “Product Metallurgy Limitations”.

Changed “OPPC” to “Testing Services”.

Section **7.9.1.2 Elastomer Selection Guidelines** Changed “Elastomer and O-ring selection guidelines have been defined for OPPC and DBR Fluids Sampling and Analysis equipment” to “Elastomer and O-ring selection guidelines have been defined for Fluids Sampling and Analysis equipment”.

Changed “OPPC, DBR and TTK designed pressure containing, sampling and pressure controlling equipment shall have as a minimum” to “All pressure containing, sampling and pressure controlling equipment shall have as a minimum”.

Section **7.10.5 Major Repairs/Re-manufacture** Inserted before the last paragraph “Bottles containing a sample do not require an annual survey but are still required to have their 5 years certification completed. Bottles that are nearing the end of their 5 years certification period should have the samples transferred to another bottle with a valid certification.”

Section **7.12 Testing Services and Wireline Asset Management**Changed “The Oilphase Product Center (OPPC), Terratek Technology Center (TTK) and DBR Technology Center (DBR-TC) will maintain the RITE File Code” to “The Product Centers will maintain the RITE File Code”.

## *F.14.8* Section 8 Amendments, Revision 8.3, January, 2015

Section **8.5.2.2 Equipment Not Containing Explosives** Changed “Perforating equipment that does contain explosives” to “Perforating equipment that does not contain explosives”.

Section **8.8.1.4 Additional Design and Planning considerations for CIRP Operations** Changed “Well Services QHSE Standard 22: Coiled Tubing Operations” to “Well Intervention QHSE Standard 02: Coiled Tubing Operations, InTouch Content ID 5884296”.

## *F.14.9* Section 9 Amendments, Revision 8.3, January, 2015

Section **9.1 Pressure Certification Procedures** Changed “A wellsite crew shall be considered qualified if the supervisor and at least 50% of the other essential crew members hold a valid certification. On multidiscipline crews, at least one operating technician or engineer per discipline must be certified. Crew members not holding a valid certification must be qualified by having completed, at a minimum, Intermediate Level 1 training.” to

“A wellsite crew shall be considered qualified if:

1. The multi-disciplinary supervisor(s) and each discipline leader (day and night) are certified as per the requirement described in the relevant discipline POM section.
2. At least 50% of the remaining crew members also hold a valid certification. Crew members not holding a valid certification must be qualified by having completed, at a minimum, Pressure Level 1 training.”

Section **9.1.9 Pressure Certifications Tables** In Table 9-2, removed certifications CS-L2, CS-FIV-L2WS, CS-FIV-L2CT and WHE-SL-L2.

In Table 9-3, removed “Replaces the ‘Advanced Surface Welltest’ certificate”, removed “Replaces the ‘Advanced Drill Stem Test’ certificate”, removed “Replaces the ‘Advanced Wellhead Equipment’ certificate. >10kpsiW”.

Section **9.1.11 TCP Pressure Certification** Changed “Well Services QHSE Standard 22: Coiled Tubing Operations” to “Well Intervention QHSE Standard 02: Coiled Tubing Operations, InTouch Content ID 5884296”.

## *F.14.10* Appendix A Amendments, Revision 8.3, January, 2015

Section **A.2.4 Fittings, Liners, and Medium/High Pressure Flexible Hoses** Added at the end of the note "It is acceptable to have 10,000 psi WP field equipment fitted with 1/4 inch or 1/2 inch NPT fitting as this equipment is only taken up to 15,000 psi Test Pressure inside a pressure test bay. Additionally, till end of 2015, fittings used during Q-Check of 15,000 psi DST equipment fall under this exception as this maintenance level shall be performed only inside Pressure Test bay. No more than one pressurized port is allowed at same time. Test Caps are covered in next section."

Section **A.4 Gauges and Recorders** Changed "Calibration should not be older than three months for any annual qualification tests" to "Calibration should never be older than twelve months for any annual or major qualification tests"

## *F.14.11* Appendix B Amendments, Revision 8.3, January, 2015

Section **B.2.4.10 ASME / ANSI flanges** Added a note below the table: "Only valid for carbon steel flanges and not for alloy flanges as rating may vary".

## *F.14.12* Appendix C Amendments, Revision 8.3, January, 2015

Section **C.1.2 Below Flowhead / Downhole Crossovers** Changed "the regional manufacturing group (RMG) in Aberdeen which has been integrated into the Oilphase Product Center and renamed OPPC RR- Crossovers Product Line" to "the regional manufacturing group (RMG) in Aberdeen which has been integrated into SRC and renamed RTST RR Crossover Group".

Changed "OPPC-RR" to "RTST-RR" throughout this section.

## *F.14.13* Appendix D Amendments, Revision 8.3, January, 2015

## *F.14.14* Appendix E Amendments, Revision 8.3, January, 2015

Section **E.4.1 Key Definitions** Changes in the definition of “Partial Pressure” and added another example.

## *F.14.15* Appendix F Amendments, Revision 8.3, January, 2015

Section **F.11 .5 Section 4 Amendments, Revision 8.0, February 2012** Corrected small errors in the titles of updated sections.

“4.4.14 Tanks” changes to “4.4.14 Transfer Pumps”

“4.4.15 Transfer Pumps” changes to “4.4.15 Tanks”

“4.4.14.1 Surge Tanks” changes to “4.4.15.1 Surge Tanks”

“4.4.14.2 Gauge Tanks” changes to “4.4.15.2 Gauge Tanks”

“4.4.14.3 Frac Flowback (Trash) Tanks” changes to “4.4.15.3 Frac Flowback (Trash) Tanks”