Pressure Effects on Subsea Hardware During Flowline Pressure Testing in Deep Water

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Contents

Introduction

Subsea hydrotesting demonstrates the structural integrity of the flowline system to tolerate the maximum allowable operating pressure (MAOP), and it confirms the sealing integrity of the pipeline system and subsea hardware components to contain hydrocarbon production. These subsea hardware components may include, but are not limited to, integral and flanged valves; flanged connections and other-end connections (OECs); jumper and flowline connectors and hubs; pressure caps and their vent valves; pressure/temperature sensors; chemical injection valves and porting; electrical penetrators; tees; crosses; pipe bends; fittings; and any similar items that will be pressurized during the subsea flowline pressure testing operations.

For subsea systems where the pressure source is at the wellhead, the MAOP is typically assigned to be equal to the wellhead shut-in tubing pressure (WHSITP). Present regulations do not allow the owner/operator to consider the gradient of produced fluids to determine a variable design pressure along flowline and riser as a function of elevation if flowline and riser are not separated by physical barriers. For more details on this issue see:

— 30 *Code of Federal Regulations* (*CFR*) 250 Subpart J, Paragraph 250.1002;

— Notice to Lessees (NTL) 2009-G28, *Alternate Compliance and Departure Requests in Pipeline Applications*;

— OTC Technical Paper 25087, *Formulating Guidance on Hydrotesting Deepwater Oil and Gas Pipelines*.

Pre-commissioning leak testing demonstrates the sealing integrity of the barriers for a fully assembled subsea production system to contain hydrocarbon production fluids (or injection fluids). The leak test pressure is normally applied as internal pressure within the flowline itself, but leak testing of individual connections may be applied as a backside seal test using test pressure from a remotely operated vehicle (ROV) or other remote pressure source. The preferred use of a backside seal test is a preliminary or cursory test to verify the integrity of a connection joint before an internal pressure test of the system. The backside pressure test is typically performed with agreement between the operator and manufacturer. The backside seal test port can also be used to monitor an individual connection for leakage during an internal pressure test (during diagnostics or troubleshooting).

There is a need to distinguish between surface shut-in tubing pressure (SSITP) and WHSITP. Standard subsea flowline hydrotest pressure typically exposes the flowline system to a differential pressure between 1.25 × MAOP and 1.5 × MAOP of the flowline at all locations and elevations. In some cases, the surface test pressure can be based on a calculated SSITP taking into account the hydrostatic head within the riser. In other cases, the surface test pressure may have to be 1.25 (or 1.5) times the full WHSITP at the seabed, with no reduction allowed for density of produced fluids in the riser. **Thus, it is important to confirm whether the surface test pressure must be based on WHSITP or if it can be reduced, based on SSITP, considering density of produced fluids in the riser.**

Pressure Effects on Subsea Hardware During Flowline Pressure Testing in Deep Water

1 Scope

This document provides guidance to the industry on allowable pressure loading of subsea hardware components that can occur during hydrotesting of subsea flowlines and risers and during pre-commissioning leak testing of these systems. There are potential problems with confusion arising from high hydrostatic pressure in deep water, partially due to the variety of applicable test specifications and partly from the inconsistent use of a variety of acronyms for pressure terminology.

With guidance, owner/operators can avoid unexpected loading conditions and the resulting potential for equipment damage, failure, or leakage (either immediate or delayed leaks) or reduced service life.

This document and the examples provided give the user guidance for evaluating subsea hydrotesting scenarios where test pressures are often well above maximum allowable operating pressure (MAOP).

2 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.

API Technical Report 17TR8, *High-pressure High-temperature Design Guidelines*

API Technical Report 17TR12, *Consideration of External Pressure in the Design and Pressure Rating of Subsea Equipment*

3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

For the purposes of this document, the following definitions apply.

3.1.1
absolute pressure
Absolute pressure inside the components being tested, measured in "psia."

3.1.2
barrier
Element forming part of a pressure-containing envelope that is designed to prevent unintentional flow of produced/injected fluids, particularly to the external environment.

3.1.3
differential pressure
Difference between the absolute pressure inside a component and the absolute pressure outside of the component at that location, measured in "psid."

NOTE For the purposes of discussions in this document, "psig" and "psid" are the same if at the same water depth.

3.1.4
external pressure
External pressure acting on the subsea equipment due to the ambient seawater pressure at the submerged depth of the equipment being tested (Po).

3.1.5
gauge pressure
Pressure gauge reading (assuming gauge is referenced to ambient pressure at the subsea depth); for example the differential between the absolute pressure inside the component being tested subsea and the external ambient pressure at the submerged depth, measured in “psig.”

3.1.6
maximum allowable operating pressure
MAOP
The single absolute pressure rating assigned, by U.S. regulator, to a flowline system including topsides to seabed limits.

NOTE 1 MAOP may be the maximum pressure determined by design of a critical section or component pressure rating.

NOTE 2 MAOP may also be the lowest design pressure of the maximum design pressures of all pipeline sections and components.

3.1.7
rated working pressure
RWP
Maximum internal pressure a piece of equipment is designed to contain and/or control.

NOTE 1 For the purposes of this technical report, rated working pressure is defined as the absolute internal pressure minus 14.7 psia (see API 6A and API 17D).

NOTE 2 Typically applies to valves, flanges, hubs, OECs, fittings, etc.

3.1.8
rated working pressure, absolute
RWPa
Manufacturer’s rated working pressure rating for the component, expressed in absolute pressure of fluid inside the component (psia).

NOTE For the purpose of this technical report, the term RWPa means the manufacturer’s rated working pressure, measured in “psia.”

3.1.9
rated working pressure, differential
RWPd
For valve bore sealing elements, the maximum allowable differential pressure across the closed valve (applies to both testing and operations).

NOTE When conducting typical factory acceptance testing (FAT) and fabrication facility pressure tests on land, RWPd is essentially equal to RWPa for practical purposes.

3.1.10
surface shut-in tubing pressure
SSITP
The maximum expected absolute internal pressure (expressed in psia) of the produced (or injected) fluids at the elevation of the surface production equipment (typically at the top of the production riser).

3.1.11
wellhead shut-in tubing pressure
WHSITP
The maximum expected absolute internal pressure (expressed in psia) of the produced (or injected) fluids at the elevation of the subsea wellhead (typically located at or near the seabed).

3.2 Acronyms and Abbreviations

DWP	differential working pressure
FAT	factory acceptance testing
MAOP	maximum allowable operating pressure
OEC	other-end connection
PLEM	pipeline end manifold
PLET	pipeline end termination
Po	external pressure
PR	Performance Requirement
ROV	remotely operated vehicle
RWP	rated working pressure
RWPa	rated working pressure, absolute
RWPd	rated working pressure, differential
SSITP	surface shut-in tubing pressure
WD	water depth
WHSITP	wellhead shut-in tubing pressure

4 Limitations on Subsea Testing Pressures

4.1 General

In this section, a number of examples are described and illustrated for possible scenarios that can occur while pressure testing a flowline and riser. These scenarios, plus any additional testing requirements that might be required or desired, should be discussed at the design review phase between client and manufacturer so that the proper equipment selection and testing procedures can be confirmed. These examples show how subsea hardware components can be subjected to pressures well above the manufacturer's rated working pressure (RWP), even when the RWP of these components appears to exceed the pressure required for the subsea flowline system test, normally 1.25 × MAOP.

It is important to note that the API RWP for the components is “absolute pressure” (psia) of the fluid contained within the equipment, and **not** the differential pressure between internal pressure and external ambient seawater pressure (psid). In this document, the term RWPa is to mean the manufacturer’s rated working pressure, measured in “psia.”

This document is applicable to API 17D, Second Edition. Additional considerations should be made for equipment designed to the following.

1) API 17TR8, relating to FAT hydrostatic test pressures:

   a) 1.5 × RWP for API RWP ≤ 20,000 psi;

   b) 1.25 × RWP for API RWP > 20,000 psi.

2) API 17TR12, relating to equipment categories:

   a) pressure-containing;

   b) pressure-controlling;

   c) subsea equipment with trapped voids (whether pressure-containing or pressure-controlling).

4.2 Case 1: Subsea Test Pressures at or Below 1.0 × RWPa

In general, there is no concern for any subsea hardware component where the subsea test pressures are at or below 1.0 × RWPa at all times, and thus below 1.0 × RWPd (see Figure 1).

A loading condition of 1.0 × RWPa is acceptable without special qualifications. However, limiting flowline hydrotest pressure to 1.0 × RWPa of the hardware components can create restraints on the maximum allowable hydrotest pressure that can be used when testing the subsea flowline system. In many cases, a pressure equal to 1.0 × RWPa of the component will be less than the required flowline hydrotest pressure (1.25 × MAOP).

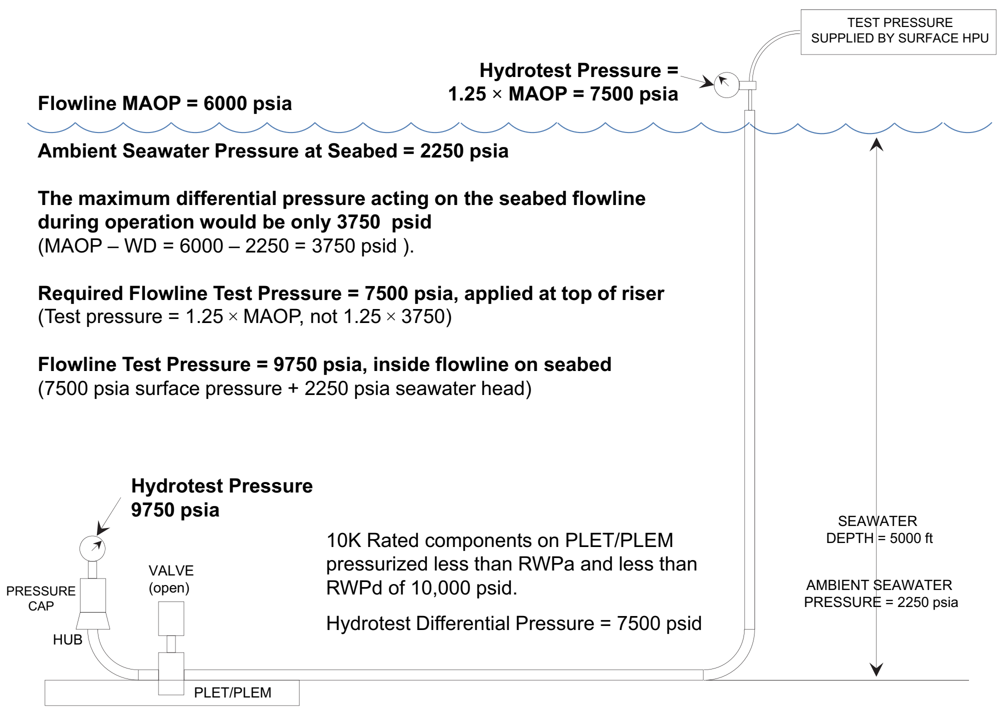

Figure 1—Commissioning Test of Subsea Flowline with Riser—Case 1

4.3 Case 2: Subsea Test Pressures Greater than 1.0 × RWPa and Not Above 1.0 × RWPd

In this example, the differential pressure (internal test pressure – external seawater pressure) does not exceed 1.0 × RPWd and the absolute internal pressure during the subsea testing does not exceed the absolute pressure actually used during shop FAT testing (typically 1.5 × RWPa) or during fabrication yard testing of assembled equipment (where test pressure is often 1.25 × MAOP, which could be less than 1.5 × RWPa) (see Figure 2). **Owner/operators should consult with the hardware component manufacturer to confirm the maximum allowable subsea test pressures for hardware components if the anticipated subsea hydrotest pressure will exceed 1.0 × RWPa at any time.**

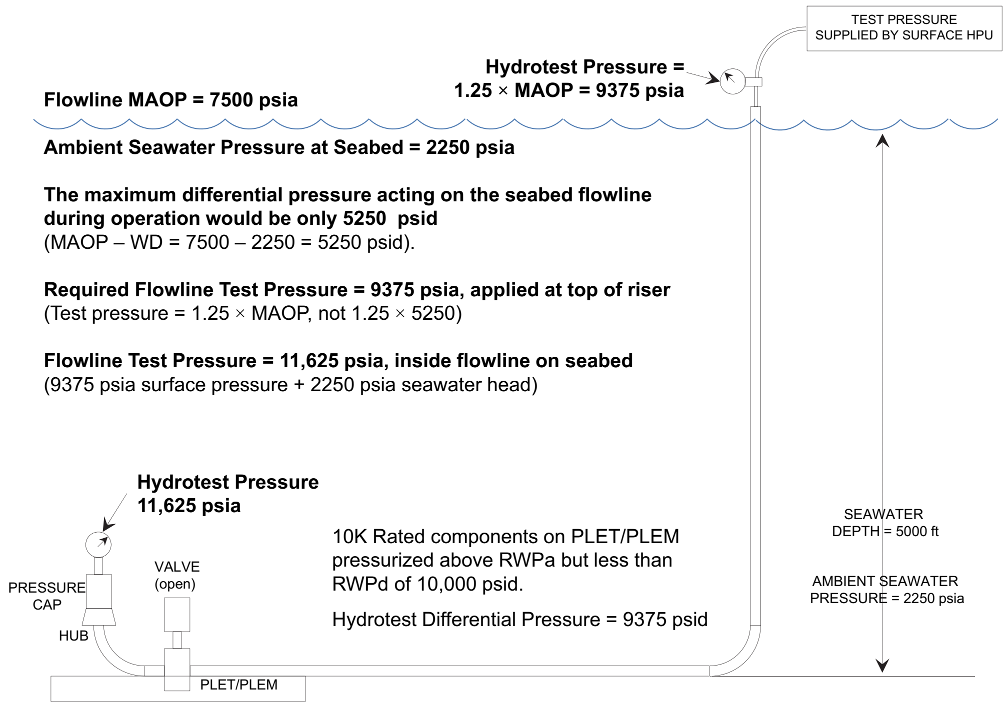

Figure 2—Commissioning Test of Subsea Flowline with Riser—Case 2

CAUTIONS

1) Some elements within subsea hardware components may have empty spaces or trapped voids between seals that contain air or other fluid at 1-atmosphere pressure, with seals that prevent the ambient seawater pressure from reaching the backside of the primary seal or barrier. The differential pressure acting on these elements is actually equal to the absolute pressure inside the hardware component during subsea testing, since the ambient seawater pressure is not present behind the primary seal. Some examples are:

   a) space between dual stem packings or other dual seal sets,

   b) space between a stem packing and an external seawater barrier seal,

   c) space behind the diaphragm within a pressure sensor,

   d) space between dual seals in electrical penetrators.

   Such elements with 1-atmosphere trapped void spaces may be damaged or may lose calibration, if absolute pressures go above 1.0 × RWPA during subsea hydrotesting operations. The owner/operator should confirm with the subsea hardware supplier the maximum absolute pressure these components can tolerate without damage or loss of calibration.

   The purchasing specifications for these components should require the manufacturer to design, test, and qualify them for the maximum anticipated absolute pressures to be used during subsea testing operations. In some cases, it may be preferable to upgrade to higher rated components that can withstand the hydrotest pressures (e.g. using 15 ksi rated pressure sensors in a 10K MAOP flowline system that must be hydrotested to 12.5 ksi).

2) Where subsea tests are conducted against pressure caps with small bleed/test valves (usually needle valves) in the cap, these valves are normally closed during subsea testing of the flowline. Such valves are not designed or intended to be used at differential pressures above their API RWP when closed (differential across the closed valve gate/needle and seat). In this regard, the RWP of these valves must be based on the maximum anticipated subsea test pressure, which is often higher than the design pressure of the flowline system.

API 6A and API 17D typically do not address how the owner/operator should use the equipment in the field, nor do the API specifications set any limitations on subsea test pressures or test durations that the owner/operator may apply to the equipment in the field. Manufacturers may assist the owner/operator in evaluating the anticipated subsea test pressures compared to the RWP of the hardware components, but the ultimate decision on component RWP selection is the responsibility of the owner/operator. Subsea hardware manufacturers typically prefer some margin between the FAT test pressure and the subsea test pressure (e.g. they may recommend that the maximum absolute pressure for subsea testing be no more than 90 % of the absolute pressure actually used during shop FAT testing), but no industry wide consensus has been established.

4.4 Case 3: Subsea Test Pressures Greater than 1.0 × RWPd (Greater than 1.0 × RWPa), but Not Above 1.5 × RWPa

All comments for Cases 1 and 2 above apply regarding component limitations that affect maximum allowable subsea test pressure.

In this example, the subsea hydrotest differential pressure is well above 1.0 × RWPd, but the subsea differential pressure does not exceed the differential pressure actually used during shop FAT testing (typically 1.5 × RWPd) or fabrication yard testing (typically 1.25 × MAOP, which could be less than 1.5 × RWPd) (see Figure 3).

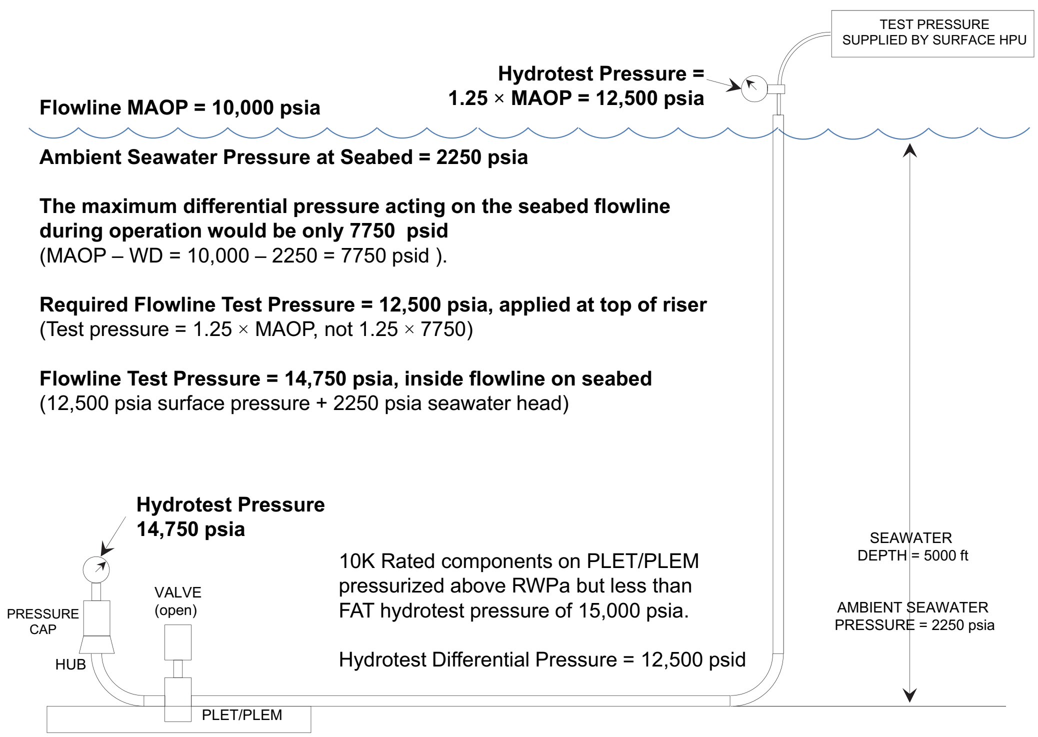

Figure 3—Commissioning Test of Subsea Flowline with Riser—Case 3

Exposing components to differential pressures greater than those used during FAT/fabrication yard testing could open up new leaks subsea. **Owner/operators should confirm with the hardware component manufacturer the maximum allowable subsea test pressure if subsea hydrotest differential pressure is to exceed 1.0 × RWPd of those items at any time.**

Owners/operators should also check with the manufacturer/fabricator of the assembled equipment to ensure that the applied pressure during flowline testing will not exceed the capacity of any associated pipework, which may not be designed to a code that requires pressure testing to 1.5 × RWPa. Manufacturers may need to modify their standard shop FAT and/or fabrication yard test pressures to ensure they are equal to or higher than the planned subsea hydrotest pressures.

As specified by API 6A and API 17D, some types of assembled equipment do not have to be hydrotest above 1.0 × RWP if all of the subcomponents used in the assembly were previously tested to the hydrostatic body proof test specified in the applicable API product specification. In general, it is not a good practice during subsea testing operations to expose hardware components to differential pressures greater than those actually used during shop FAT or fabrication yard hydrotest (in the final "as-shipped" configuration). Whenever subsea hydrotest pressures are expected to be above 1.0 × RPWd, owner/operators should confirm with the manufacturer the actual hydrotest pressures used during manufacture and agree on the maximum allowable subsea hydrotest pressures.

The shop hydrotesting of all top level assemblies should be conducted at a higher differential pressure than what will be used subsea. This practice exceeds the API 6A and API 17D requirement that allows shop testing top level assemblies to only 1.0 × RWP, but it is considered a prudent practice. Such testing may require additional safety precautions during final hydrotesting due to the larger volume of fluid under pressure (which increases the danger from stored energy within the system during hydrotesting). Additional safety barriers and/or separation distances between test items and personnel/property should be considered in such cases. These issues should be considered if/when it is necessary to disassemble a component from a finished and tested assembly, such as removing and replacing a valve or sensor on a subsea tree or manifold. Such service operations are frequently conducted at fabrication yards or dockside, and common practice has been to only test the replaced item to 1.0 × RWP, rather than repeat the 1.5 × RWP hydrotest.

CAUTIONS

1) In general, hydrotest pressures greater than 1.0 × RWPd must never be applied across closed valves, since these items are normally not designed to accommodate differential pressures across the closed gate/seat mechanism in excess of 1.0 × RWPd. During subsea testing, means must be provided to ensure that differential pressure across any closed valves never exceeds 1.0 × RWPd. Use of trapped back pressure or reverse pressure behind the closed valve is not normally sufficient unless means are provided to monitor downstream pressure in real time during the subsea test to confirm that differential pressure across the closed valve never exceeds 1.0 × RWPd. Ball valves should be partially open and gate valves fully open during hydrotesting, unless conditions stated above are followed to prevent more than 1.0 × RWPd, differential across the closed valve.

2) Some component manufacturers do not approve subsea test pressures above 1.0 × RWPd under any circumstances, or may only approve on a case-by-case basis after careful review of specific project details. Some components, such as pressure sensors, may not be approved for pressures above 1.0 × RWPa without affecting calibration. In other cases, components may be able to tolerate higher pressures, but owner/operators should confirm such capability with the manufacturer. Where components cannot tolerate test pressures above 1.0 × RWPa, it may be necessary to select a component having a higher standard RWP, or it may be necessary to conduct special qualification testing on the hardware to simulate the maximum anticipated loading conditions during subsea testing operations.

3) Some manufacturers may recommend leaving a safety factor between the actual differential pressure used in shop FAT hydrotests compared to the anticipated subsea hydrotest differential pressures (e.g. the maximum differential pressure for subsea testing be no more than 90 % of the actual differential pressure used during shop hydrotesting operations), but no industry wide consensus has been established. **Owner/operators should review the anticipated subsea hydrotest pressures with the manufacturer(s) early in the project and obtain concurrence for any planned subsea test pressures above 1.0 × RWPd.**

4.5 Case 4: Subsea Test Pressures Greater than 1.5 × RWPa, but Not Above 1.5 × RWPd (or 1.25 × MAOP)

All comments for Cases 1, 2, and 3 above apply regarding component limitations that affect maximum allowable subsea test pressure.

Subsea hydrotest pressures above 1.5 × RWPa should not be used unless special evaluation, design/stress analysis, and/or qualification testing has been successfully completed to verify that hardware components will not be damaged and will continue to perform as expected (see Figure 4). Typical areas of concern are valve stem seal assemblies, pressure sensors, electrical penetrators, or other subcomponents that may have 1-atmosphere trapped volumes between elements within the component. API 17TR12 discusses these issues in more detail and provides recommendations on how to evaluate equipment for such loading conditions. It should be noted as well that external pressure may not always offset internal pressures on a one-to-one basis, as explained in API 17TR12.

Qualification testing for exposure to pressures above 1.5 × RWPa should accurately simulate the maximum anticipated internal and external pressures the components will experience during the subsea flowline hydrotest (hyperbaric chamber testing required).

Qualification testing should also expose the components to the maximum anticipated offshore hydrotest pressure hold durations (typically 8 to 24 hours or more, compared to 15 minutes holds during normal manufacturing FAT). Consideration should be given to repeating the simulated hydrotest pressure exposure test several times to simulate instances where the subsea flowline system may require multiple hydrotest cycles (e.g. if leaks are detected and diagnostics efforts require repeated de-pressure and re-pressure applications).

After the simulated repeat hydrotests, the hardware components should undergo complete API performance verification testing [such as Performance Requirement (PR) 2 testing] to confirm the components are still fit to perform as expected and service life expectancy has not been reduced (e.g. abnormal extrusion of seals during the overpressure test could result in shorter cycles to failure in operation).

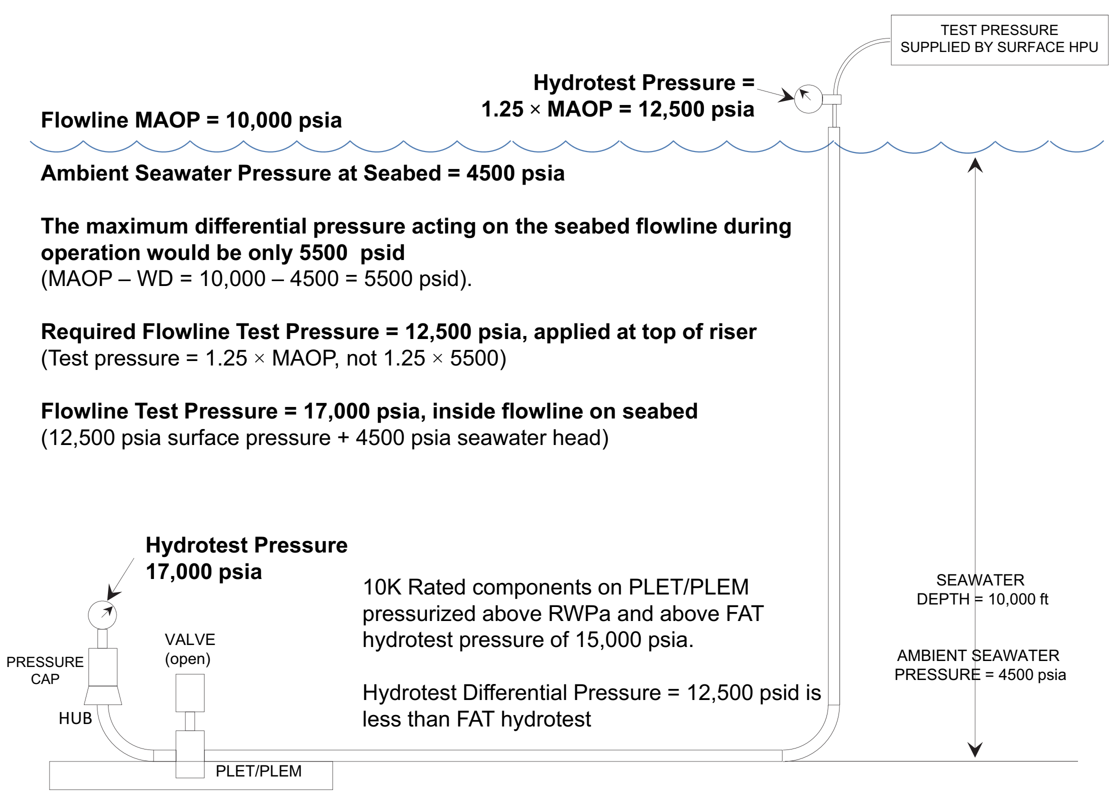

Figure 4—Commissioning Test of Subsea Flowline with Riser—Case 4

Even if the above qualification testing program is completed for subsea components that will be exposed to subsea hydrotest pressures above 1.5 × RWPa, shop FAT hydrotesting of production components and assemblies at these internal/external pressure conditions is probably not practical or economically feasible since use of large hyperbaric chambers would be required. Consequently, the actual production components for the subsea flowline system are most likely only tested to 1.5 × RWPa (and hence 1.5 × RWPd) during shop FAT hydrotests.

Exposing individual components to higher absolute or differential pressures subsea than applied during FAT must be recognized as a potential risk factor. Further, some manufacturers may recommend leaving a safety factor between the actual differential pressure used in shop FAT hydrotests compared to the anticipated subsea hydrotest pressures. **Owner/operators should review the anticipated subsea hydrotest pressures with the manufacturer(s) early in the project and obtain concurrence for any planned subsea test pressures above 1.5 × RWPa.**

Concern has been expressed by some equipment manufacturers that one needs to consider other implications of allowing such high test pressures, such as:

1) how many times is the test pressure to be cycled?

2) how long is the pressure to be maintained? or

3) is the equipment being tested still in "like new" condition if it has been previously used or has been in extended storage?

Case 3 could exceed the typical qualification program carried out by subsea equipment manufacturers and Case 4 likely crosses the manufacturer's threshold of what can be allowed without further analysis and requalification

4.6 Case 5: Subsea Test Pressure over 1.5 × RWPd—Not Recommended

Subsea testing should never expose components to pressures above 1.5 × RWPd under any circumstances for the following reasons.

1) In accordance with API 6A and API 17D design requirements, the peak stresses within hardware components may be at, or slightly above, material yield stress during the 1.5 × RWPd FAT hydrotest. Higher differential pressures may result in damage or distortion of components.

2) FAT hydrotest pressure is typically held for rather short durations (a few 15-minute hold periods), compared to subsea hydrotesting, where pressure hold durations are typically measured in many hours or even days. Exposing components to stresses at or above yield for long periods of time is not a recommended practice.

3) Repeated stressing of components to yield or above during subsea testing can result in a reduction of fatigue life in service. This may be a significant issue for highly stressed components where fatigue life is an important design consideration.

5 Separate Testing of Subsea Flowline and Riser

Another approach to pressure testing of subsea flowlines and riser systems may be to use some means to pressure test the subsea flowline system and associated hardware separately from the pressure test of the riser. This would avoid having to impose the effects of the riser's hydrostatic head on the subsea test pressures when conducting the hydrotest of the seabed flowlines.

In some cases, the subsea system configured may easily allow a separate test of the subsea flowline from the riser, for example if there is a pipeline end termination (PLET) at the riser base with suitably rated valves or pressure caps to allow separate testing operations.

Additionally, another option for separate testing could be to utilize a retrievable latching/sealing plug or pig near the base of the riser, allowing separate test pressures on different sides of the plug. In this case, the riser would be tested by applying pressure as described in Cases 1 through 4 above, pressurizing against the plug from the top side. The effects of hydrostatic pressure would ensure that the riser is subjected to a uniform differential pressure test along its entire length. The flowline could then be separately tested to 1.25 × MAOP of the flowline, pressurizing against the opposite side of the plug, and there would be no need to add ambient hydrostatic pressure to the 1.25 × MAOP test pressure.

6 Recording of Subsea Pressure Tests

When conducting subsea flowline tests, the pressures and durations and the number of repeat tests should always be recorded, and these records should be retained for the life of the project in case there are problems with the subsea hardware items. Having information on the actual pressure levels and durations and number of tests conducted can be extremely valuable to diagnostic efforts should any problems arise with the subsea hardware (either immediate or delayed performance issues).

7 Testing of New vs Old Equipment

It should be noted that the discussions above on subsea testing pressure considerations apply to newly manufactured or remanufactured hardware components that are in “like new” condition. For cases where the condition of the subsea components is not known, or where they may have been compromised due to long term exposure to the elements during shipping or storage, normal use or misuse, or any other conditions where degradation of the equipment could have occurred, the operator should consult with the manufacturer to confirm the equipment is in an acceptable condition for the planned subsea test pressure loading.

Bibliography

[1] 30 *Code of Federal Regulations* (*CFR*) 250 Subpart J, *Pipelines and Pipeline Rights-of-Way*, Paragraph 250.1002

[2] API Recommended Practice 1111, *Design, Construction, Operation and Maintenance of Offshore Hydrocarbon Pipelines (Limit State Design)*

[3] API Specification 6A, *Specification for Wellhead and Christmas Tree Equipment*

[4] API Specification 17D, *Design and Operation of Subsea Production Systems—Subsea Wellhead and Tree Equipment*

[5] Notice to Lessees (NTL) 2009-G28, *Alternate Compliance and Departure Requests in Pipeline Applications*

[6] OTC Technical Paper 25087, *Formulating Guidance on Hydrotesting Deepwater Oil and Gas Pipelines*

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