

Recommended Practice for Subsea Capping Stacks

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Contents

	Page
1 Scope	1
2 Normative References	1
3 Terms, Definitions, and Abbreviations	2
3.1 Terms and Definitions	2
3.2 Abbreviations	4
4 System Requirements	4
4.1 General	4
4.2 Subsea Capping Stack Categories	5
4.3 Interface Descriptions	6
4.4 System Design and Functional Requirements	8
4.5 Manufacturing	24
5 Use of a Subsea Capping Stack	28
5.1 Initial Actions	28
5.2 Equipment Notification and Callout	28
5.3 Well Condition Assessment	29
5.4 Deploying the Subsea Capping Stack	32
5.5 Operating Parameters	35
5.6 Operating Personnel	37
5.7 Logistics and Deployment Plans	38
6 Preservation, Maintenance, and Testing	39
6.1 Testing	39
6.2 Maintenance	46
6.3 Inspections	50
6.4 Preservation	51
6.5 Testing, Maintenance, Inspection, and Preservation Personnel	56
Annex A (informative) Subsea Well Capping Contingency Procedures	58
Annex B (informative) Example Procedures	61
Bibliography	65
Figures	
1 Category 1 (Cap)	5
2 Category 2 (Cap and Flow)	6
3 Example of Three Likely Subsea Capping Stack Attachment Points	30
Tables	
1 Example of Pre-deployment Interface Testing Matrix	33
2 Example Routine Testing Schedule	40
3 Example Non-routine Testing Schedule	40
4 Example ROV Interface Testing	42
5 Example Periodic Maintenance Schedule	46
6 Subsea Capping Stack Field Performance Report Example	48

Recommended Practice for Subsea Capping Stacks

1 Scope

This document provides subsea capping stack recommended practices for design, manufacture, and use. The document applies to the construction of new subsea capping stacks and can be used to improve existing subsea capping stacks. The document can aid in generating a basis of design (BOD) document as well as preservation, transportation, maintenance, testing documents, and operating instructions.

This document presents recommendations for neither procedures nor equipment for containment systems that may be connected to a subsea capping stack. All equipment and operations downstream of the subsea capping stack are considered part of a containment system and are not within the scope of this recommended practice.

Annex A contains a discussion of possible subsea capping contingency procedures. Annex B contains example procedures for deployment, well shut-in and recovery of a subsea capping stack.

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.

The following referenced documents are useful in 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 Specification 6A, *Specification for Wellhead and Christmas Tree Equipment*

API Specification 6AV1, *Specification for Validation of Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service*

API Specification 7-1, *Specification for Rotary Drill Stem Elements*

API Specification 7-2, *Specification for Threading and Gauging of Rotary Shouldered Thread Connections*

API Specification 14A, *Specification for Subsurface Safety Valve Equipment*, 11th Edition, October 2005, Reaffirmed 2012

API Specification 16A, *Specification for Drill-Through Equipment*

API Specification 16C, *Choke and Kill Systems*

API Specification 16D, *Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment*

API Recommended Practice 17A, *Design and Operation of Subsea Production Systems—General Requirements and Recommendations*

API Specification 17D, *Design and Operation of Subsea Production Equipment*, 2nd Edition, May 2011

API Recommended Practice 17G, *Recommended Practice for Completion/Workover Risers*

API Recommended Practice 17H, *Recommended Practice for Remotely Operated Vehicles (ROV) Interfaces on Subsea Production Systems*

API Specification 20E, *Alloy and Carbon Steel Bolting for Use in the Petroleum and Natural Gas Industries*

API Standard 53, *Blowout Prevention Equipment Systems for Drilling Wells*

API Specification Q1, *Specification for Quality Management System Requirements for Manufacturing Organizations for the Petroleum and Natural Gas Industry*

API Specification Q2, *Specification for Quality Management System Requirements for Service Supply Organizations for the Petroleum and Natural Gas Industries*

DNV Cert No 2.7-3 ¹, *Portable Offshore Units*

DNV-RP-B401, *Cathodic Protection Design*

ISPM No. 15 ², *International Standards for Phytosanitary Measures No. 15 (covers international packaging controls to prevent accidental shipment of insects, etc. across international borders)*

NACE MR0175 ³, *Petroleum and Natural Gas Industries—Materials for Use in H₂S Containing Environments in Oil and Gas Production*

NACE SP0176, *Corrosion Control of Submerged Areas of Permanently Installed Steel Offshore Structures Associated with Petroleum Production*

SAE AS4059 ⁴, *Cleanliness Classification for Hydraulic Fluids*

3 Terms, Definitions, and Abbreviations

3.1 Terms and Definitions

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

3.1.1

barrier

A tested or verified object that prevents uncontrolled flow from the subject well to the environment.

3.1.2

containment

The act of directing wellbore fluid flow in a controlled manner downstream of the subsea capping stack.

3.1.3

containment system

Any system or component downstream of the subsea capping stack that directs flow.

¹ Det Norske Veritas, Veritasveien 1, 1322, Hovik, Oslo, Norway, www.dnv.com.

² International Standards for Phytosanitary Measures, International Plant Protection Convention (IPPC), Food and Agriculture Organization, Viale delle Terme de Caracalla, 00153 Rome, Italy

³ NACE International (formerly the National Association of Corrosion Engineers), 1440 South Creek Drive, Houston, Texas 77084-4906, www.nace.org.

⁴ SAE International (formerly the Society of Automotive Engineers), 400 Commonwealth Drive, Warrendale, Pennsylvania 15096-0001, www.sae.org.

3.1.4 design and development verification

Verification performed in accordance with planned arrangements that the resulting product is capable of meeting the requirements for the specified application or intended use, where known.

NOTE Verification can include one or more of the following:

- a) prototype tests;
- b) functional or operational tests of production products;
- c) tests specified by industry standards or regulatory requirements;
- d) field performance tests and reviews.

3.1.5 divert

To redirect the flow from the well. In the case of a capping stack, to provide one or more alternative flow paths from the main flow path.

NOTE The flow capacities of all the diverter line flow path(s) in a capping stack are normally sized such that all the flow from the well can be diverted when the vertical flow path is shut off.

3.1.6 incident well

A subsea well with uncontrolled flow to the environment.

3.1.7 management of change

A systematic approach to identifying and documenting changes in equipment, process, design, procedures, or personnel.

3.1.8 pressure containing

A component whose failure to function as intended results in a release of wellbore fluid to the environment.

3.1.9 pressure integrity

The ability of an object to contain applied pressure.

3.1.10 subsea capping stack

A subsea mechanical barrier having the capability to shut in and divert uncontrolled flow.

3.1.11 validation

Confirmation that the operational requirements for a specific use or application have been fulfilled, through the provision of objective evidence.

NOTE Typically, validation is achieved by qualification testing and/or system integration testing.

3.1.12 verification

Confirmation that specified design requirements have been fulfilled, through the provision of objective evidence.

NOTE Typically, verification is achieved by calculations, design reviews, and hydrostatic testing.

3.2 Abbreviations

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

ΔP	differential pressure
BOD	basis of design
BOP	blowout preventer
CFD	computational fluid dynamic
FAT	factory acceptance test
FMECA	failure mode effects and criticality analysis
GOR	gas oil ratio
H ₂ S	hydrogen sulfide
HPU	hydraulic prover unit
ICS	Incident Command System
Kpsi	1000-psi (pressure)
LMRP	lower marine riser package
MOC	management of change
MSDS	material safety data sheet
OEM	original equipment manufacturer
P&ID	pipng and instrumentation diagram
PFD	process flow diagram
PM	planned maintenance
PSL	product specification level
ROV	remotely operated vehicle
RP	recommended practice
RWP	rated working pressure
SIT	system integration test
SWL	safe working load
UV	ultraviolet

4 System Requirements

4.1 General

This section gives details of recommended design considerations for subsea capping stacks. The recommended considerations address functionality and operability and provide a basis for equipment selection. The well and rig specific functional requirements for a subsea capping stack should be communicated to the manufacturer or provider of the subsea capping equipment and services. The topics of this document should be incorporated in a BOD document as a communication tool to the subsea capping stack supplier or manufacturer.

All subsea capping stacks shall:

- be equipped with the capability to monitor pressure below each vertical bore mechanical closure device;
- provide a means to inject hydrate inhibitors and chemicals into the main vertical bore, at a position below the diverter outlets;
- contain one or more outlets for diverting flow from and/or pumping kill fluid into the main vertical bore; and

- follow the guidelines set forth by API 16A, API 17D, and API 17G for design, qualification, and validation of subsea equipment. (For certain components, detailed later in this recommended practice, additional requirements from API 16D and API 6A may also be applied.)

All subsea capping stacks should:

- use field proven and qualified equipment components; and
- provide a means for venting trapped gas from below the top vertical flowpath mechanical closure component.

Final verification of a fit-for-purpose subsea capping stack design should be thoroughly documented and performed by a responsible party at the time of a specific incident.

4.2 Subsea Capping Stack Categories

4.2.1 General

This document focuses on the recommended practices for two categories of subsea capping stacks:

- Category 1 (Cap);
- Category 2 (Cap and Flow).

4.2.2 Category 1 (Cap)

To use a subsea capping stack on a Category 1 (Cap) well, the wellbore shall be capable of maintaining pressure integrity during and after shut-in of the subsea well. Category 1 subsea capping stacks shall have the ability to connect to a flowing well, to shut in the well, to temporarily divert wellbore fluids in order to facilitate closure of the main bore, and to interface to pumping equipment for kill fluid injection into the wellbore. The Category 1 subsea capping stacks should have the general configuration in Figure 1.

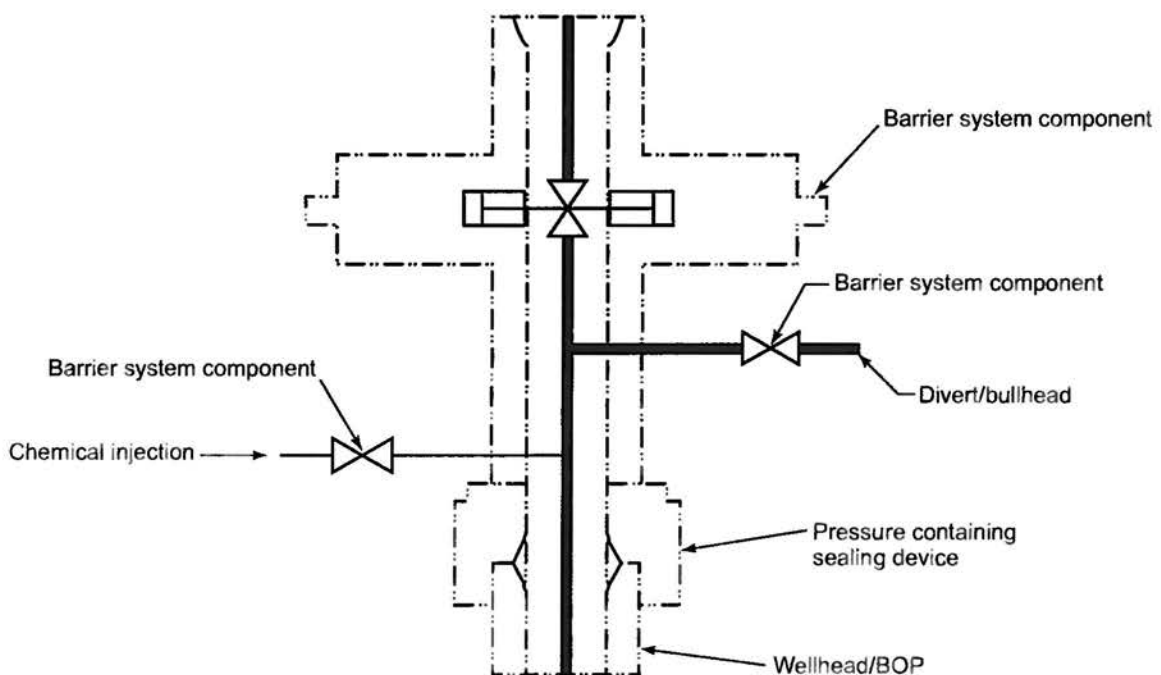


Figure 1—Category 1 (Cap)

4.2.3 Category 2 (Cap and Flow)

For circumstances where the wellbore may lose pressure integrity during shut-in, a Category 2 subsea capping stack shall be used. Category 2 subsea capping stacks shall have the ability to connect to a flowing well, to shut in the well, to divert wellbore fluids, to interface to pumping equipment for kill fluid injection into the wellbore, and to control the rate of flow through the diversion outlet(s) with a choking device. The Category 2 subsea capping stacks should have the general configuration in Figure 2.

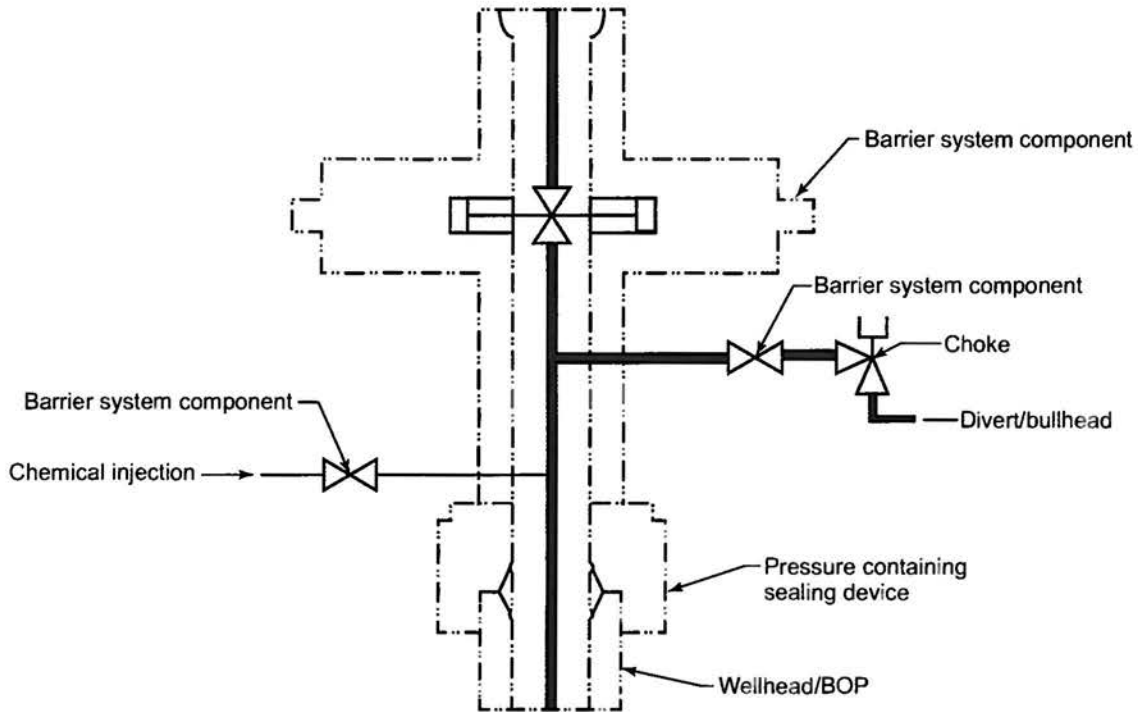


Figure 2—Category 2 (Cap and Flow)

4.3 Interface Descriptions

4.3.1 General

The purpose of a subsea capping stack is to shut in uncontrolled flow from a wellbore to the environment (Category 1) or, to divert flow from the wellbore to a containment system (Category 2.) A subsea capping stack may also provide the following functionality:

- inject kill fluids into the wellbore;
- facilitate chemical injection (hydrate inhibitor and dispersant);
- facilitate monitoring of critical wellbore parameters (i.e. pressure and temperature); and
- contain standardized interfaces on all inlets, outlets and handling tool connection points.

Mechanical interface connections on any subsea capping stack are typically multifunctional and are required to interface with a variety of rig and vessel running tools and containment system connection systems. It is critical that these interfaces be understood, documented, and planned for prior to any incident requiring the use of a subsea capping stack.

4.3.2 Systems Interfaces

4.3.2.1 Attachment to Incident Well

Several system and subsystem interfaces exist in subsea capping stacks. The early identification of these areas minimizes problems, inconsistent designs, and delays in operations during an incident. Subsea capping stack design documentation shall clearly indicate interface attachment points.

The primary attachment point to an incident well is most often to a user-defined industry recognized connection conforming to the standards of API 6A for flange connections and API 17G for other connections. This attachment is typically accomplished using an actuated hydraulic wellhead-style connector provided at the bottom of the subsea capping stack. This primary attachment point can be at the top of the BOP stack, subsea wellhead, or the subsea tree. The connection interface between the BOP and LMRP may not match the wellhead and tree profile.

The points of an incident well that a subsea capping stack most likely interfaces with are:

- 1) at the blowout preventer (BOP) top mandrel;
- 2) at the wellhead mandrel;
- 3) at the tree reentry mandrel interface; or
- 4) at the LMRP to riser flex joint connection.

Nonstandard connectors and connection hubs should be avoided on subsea capping stacks as it may be difficult to procure interfacing equipment during an incident.

If the subsea capping stack connection is above the flex joint, the load capacity and pressure rating of the assembly may be reduced. If this connection is chosen for the capping stack, the design should include an analysis to determine if additional structural support is necessary.

4.3.2.2 Attachment of External Flow Paths

External flow equipment such as jumpers, manifolds, and risers may interface with the subsea capping stack for bullheading and killing the well or for flowing the incident well to a containment system.

As with the vertical interface to the incident well, this attachment should rely on remote connection technology and may be based on flowline connection or (large-bore) hot stab technologies. In either case, and as with the well attachment, subsea capping stack designs should incorporate industry-standard connections and connectors to allow the maximum amount of flexibility during a subsea capping incident.

For flowline connection points and high flow hot stabs provided by subsea equipment vendors that may be proprietary in nature and not easily convertible to a universal connection type, subsea capping stack owners should procure the necessary connection equipment such as goosenecks, rigid jumpers, pressure caps, hot stabs, and running tools required for tie-back of the subsea capping stack to the intended containment system.

4.3.2.3 Attachment to Top of Subsea Capping Stack

The top interface of the subsea capping stack may connect to installation handling tools and rigging, an additional subsea capping stack, or a containment system. For this reason, the top mandrel interface of the subsea capping stack shall be pressure containing, rated to the full working pressure of the subsea capping stack, and allow for attachment to a subsea hydraulic connector.

The attachment interface at the top of the subsea capping stack shall be a user-defined industry recognized connection conforming to API 6A for flange connections and API 17G for other connections. The functions of this interface may include accepting an additional subsea capping stack, handling/installation tools, or attaching flow/pump equipment. The attachment of any equipment to the subsea capping stack shall be analyzed and modeled to determine loads, fatigue, and induced stresses to the subsea capping stack and to the existing incident well equipment (including, but not limited to, the incident wellhead, incident BOP stack, incident subsea capping stack, etc.) to determine the integrity, operating limits, and fatigue life of the entire system.

4.3.2.4 External Controls and Monitoring

Control of subsea capping stacks should rely primarily on remotely operated vehicle (ROV) intervention. Data monitoring should also rely on ROV intervention. Control and data connection to external controls may involve more complex components such as subsea control modules and accumulator packages. These should be positioned separately and connected by flying leads to reduce the size, weight, and complexity of the capping stack. As a minimum, data monitoring on subsea capping stacks should be via ROV-readable gauges for real-time and continuous feedback of sensors and gauges.

4.4 System Design and Functional Requirements

4.4.1 General

The design of a subsea capping stack is affected by factors including service environment, preservation environment, transportation requirements, component design, and post-installation functionality requirements. During design of a subsea capping stack, these factors should be reviewed and analyzed to determine the optimal design requirements.

The subsea capping stack shall be suitable for the well conditions where it will be applied and verified by computational modeling, flow analysis, structural capability of the well to sustain subsea capping loads, and ability of the wellbore to sustain shut-in or contained flow pressures.

4.4.2 Service Conditions

4.4.2.1 General

Service conditions refer to pressure, temperature, material classification, wellbore constituents, and other operating conditions for which the equipment is designed. Equipment shall conform to the API conventions set forth throughout this document.

4.4.2.2 Pressure Ratings

Working pressure ratings of all subsea capping stacks shall conform to industry standards set forth by API 17G.

4.4.2.3 Temperature Ratings

Temperature classifications indicate temperature ranges from minimum (ambient) to maximum flowing fluid temperatures. Subsea capping stacks and their components shall conform and be designed to operate within the temperature classification conventions set forth by API 17G. Typically, the minimum temperature is the lowest ambient temperature that the equipment may be subjected to during operation, transportation, and preservation while the maximum temperature is encountered during flowing conditions.

Unless other requirements are identified, the minimum classification for pressure-containing and pressure-controlling materials should be temperature classification U [-18 °C (0 °F) to 121 °C (250 °F)]. The design shall address the effects of thermal expansion and contraction from temperature changes that the equipment can experience in service.

The effects of Joule-Thompson cooling and imposed flowline heating or heat retention (insulation) shall also be considered. Thermal analysis can be used to establish component temperature-operating requirements. API 17G provides information for design and rating of equipment for use at elevated temperatures.

4.4.2.4 Flow Capacity

4.4.2.4.1 General

The maximum flow capacity of a subsea capping stack design shall be determined by the lesser of the acceptable limit of erosion within the subsea capping stack or the acceptable pressure drop across subsea capping stack components.

CFD analysis should be used to determine the estimated gas and oil flow rate capacity of the stack, including flow rates at a range of GOR combinations, in the following configurations:

- vertical main bore open and all diversion outlets open;
- vertical main bore open and all diversion outlets closed;
- vertical main bore closed and all diversion outlets open;
- vertical main bore closed and consecutive diversion outlets closed until a single outlet is open; and
- vertical main bore closed and consecutive diversion outlets closed until the required number of flowing outlets are open.

The subsea capping stack designer shall document the internal flow path dimensions of the subsea capping stack for reference by the incident owner when planning or assessing for the use of the subsea capping stack.

4.4.2.4.2 Solids Content

Because flow from an incident well may have high concentrations of solids, subsea capping stack designs should be analyzed through CFD to determine areas of high erosion. Subsea capping stack designs shall incorporate available technology to reduce the effects of erosion in areas identified by this CFD analysis. Critical areas of the subsea capping stack should be designed and tested to conform with API 6AV1 Class II for sandy service.

4.4.2.5 Operating Water Depth

The subsea capping stack BOD should include the range and maximum operating water depths for its application. For subsea capping stacks manufactured with a global perspective, the operating water depth should be at least 10,000 ft.

4.4.2.6 Modular Designs

The subsea capping stack designer should consider modularity, or the ability to quickly segment the subsea capping stack into smaller and lighter modules, to address service and repairs, transportation and rig or vessel installation limitations. Modular designs may require significant additional time for reassembly and dock/deck testing. Planning for different modes of transportation identifies size and weight limitations during the design phase.

The weight and dimensions of the subsea capping stack are critical with respect to its operability, transportation, handling, and deployment. Transfers on and off of trucks, airplanes, and vessels can be more efficient for smaller and lighter module loads.

The overall dimensions of the subsea capping stack can limit transport and installation options. Transportation factors include bridge clearances for road transport and crane boom reach/lift; A-frame clearance and reach; sea-fastening; weight and size limitations for air transport; and moonpool clearance for rig and vessel installations.

4.4.2.7 Service Life

A subsea capping stack should be designed for two years of installed subsea service, which includes six months of continuous flowing service, and a minimum of 20 years land-based preservation and maintenance service. Manufacturers shall demonstrate and document the design and material selection in line with anticipated service life of the equipment.

Life estimation and aging of components and materials within the subsea capping stack assembly shall be based on API 17D, Annex J. Where available, manufacturer may base the life estimation on known component failure and deterioration data (meantime between failure and shelf life). The manufacturer shall define additional applicable design and development re-verification and shelf life replacement schedules and demonstrate these schedules can be correlated with the intended service life and/or operating conditions in accordance with the purchaser requirements.

Life estimation shall account for proper preservation, maintenance, periodic design and development re-verification, and testing and replacement routines. Selection of elastomeric and thermoplastic materials shall take into account the potential deterioration under surface UV light and dry rot conditions.

Manufacturers shall provide documentation on preservation environment requirements, periodic design re-verification, function and pressure testing for readiness, and the preparations required for deployment and subsea use.

4.4.2.8 Cathodic and Corrosion Protection and Coatings

External corrosion control for equipment shall be provided in the design by appropriate materials selection, coating systems, and cathodic protection.

Electric continuity tests shall be performed to prove the effectiveness of the cathodic protection system. If the electrical continuity is not obtained, earth cabling or other suitable means shall be incorporated in the ineffective areas where the resistance is greater than 0.10 Ω .

Selection of stud, nut, and bolting materials and coating/plating should consider seawater-induced chloride stress corrosion cracking and corrosion fatigue. High-strength bolting materials for service in a seawater environment shall conform to API 17D, NACE SP0176, and DNV RP B401.

Methods to avoid hydrogen embrittlement induced by cathodic protection systems should be considered in the design of the subsea capping stack.

Selection of a coating system shall take into account the need for long-term preservation and potential deterioration of subsea coating systems under surface UV light conditions.

The manufacturer shall maintain, and have available for review, documentation specifying the coating systems and procedures used. The documentation shall describe specific preservation requirements related to the coating system.

Color selection for underwater visibility shall be in conformance with applicable sections of API 17A and 17H.

4.4.2.9 Design for Preservation

Equipment design should incorporate material allowances for repairs, refacing, recoating, and recertification to address extended preservation requirements, environmental exposure, and repeated function and pressure testing of the subsea capping stack equipment.

Subsea capping stack shall be designed to minimize exposed seals and seal surfaces. Any exposed seals/sealing surfaces and threads should be protected from damage. The subsea capping stack components or modules should be designed such that equipment does not rest on any seal or sealing surface during shipment or preservation.

4.4.3 Component Design

4.4.3.1 General

High-quality, reliable, and field-proven components capable of withstanding extended periods of surface preservation, frequent surface testing, and (for Category 2 system only) six-month continuous subsea flowing sandy service conditions should be used on subsea capping stacks. These components should be traceable through their manufacturing processes and qualified to perform their intended function under the conditions of an incident well. The following sections give detail to these topics for major components of the subsea capping stack.

4.4.3.2 Bore Size

The subsea capping stack bore size should depend primarily on the ability to install the cap in the flow stream of an incident well at maximum flowing conditions. The forces on the cap from the incident well depends on flow rate, water depth, GOR, and flow path geometry including outlet sizes and the decision to run the cap with the outlets opened or closed during installation. Bore sizes shall be in conformance with API 6A and API 16A.

A CFD analysis shall be performed to determine and verify the subsea capping stack's planned bore sizes for the main bore vertical outlet as well as for the number and size of each diversion outlet. The cap's bore designs are also influenced by the diversion outlet closure sequence. A thorough fluid analysis shall be performed to determine the effect of these parameters.

4.4.3.3 Erosion and Debris Tolerance

4.4.3.3.1 General

In a blowout situation, solids such as hydrates, weighting agents, formation sands, drilling cuttings, and proppants may be a component of the blowout mixture and lead to erosion of critical components within the subsea capping stack.

Devices used to shut off flow shall be designed to mitigate the effects of erosion and be designed and tested to conform to API 6AV1 Class II for sandy service. Features that may reduce the effects of erosion include:

- multiple flow paths;
- hardened inlays in areas of high erosion;
- full bore, straight-through component design; and
- replaceable wear component design.

4.4.3.3.2 Component Erosion Resistance

Subsea capping stack component OEMs and subsea capping stack designers and manufacturers shall determine the maximum acceptable velocities of sandy service flow across supplied subsea capping stack components (closure devices, valves, chokes, piping elbows, etc.). This information determines the erosion resistance and performance capabilities of that component and affects the overall design limitations of the subsea capping stack. Erosion may be mitigated by reduced velocities in flowlines, valves, outlets, chokes, etc. An exception to this is during short exposure periods when velocities may spike just before a valve fully closes.

Components design shall include fluid flow analysis to identify areas susceptible to high erosion and system designs shall minimize erosion in areas identified as such by this analysis.

4.4.3.3.3 Erosion of Choking Devices

Subsea choking devices should be of a robust design capable of withstanding limited flow with debris and designed and tested to conform to API 6AV1 Class II for sandy service.

4.4.4 Access to Components for Repair, Replacement, and Maintenance

The design of the subsea capping stack should accommodate access to individual components to simplify field repairs, shop repairs, and maintenance. The design should, where possible, allow for access to individual components, identified as needing frequent repairs or replacement, such that service technicians can easily make in-field repairs. This will speed up the repair or replacement process.

Critical components susceptible to frequent wear and erosion, such as choking devices and choke or connector gaskets, should be replaceable while the subsea capping stack remains subsea and incorporate a means to verify the integrity of the connection after replacement.

4.4.5 Flow Isolation Barriers

4.4.5.1 General

Isolation of defined flow paths can be achieved by the use of engineered components qualified to provide isolation under defined flowing conditions. This can be achieved by a variety of closure devices.

4.4.5.1.1 Ram as a Closure Device

A ram used as the vertical bore closure device should be qualified to close on the maximum flow defined by the subsea capping stack BOD. In the absence of a qualified ram, a second vertical bore closure device should be included. Any ram devices incorporated into the subsea capping stack design should be in conformance with API 16A and API 53. Rams should also be designed and qualified for flow with solids, considering the effects of erosion and the effects of solids accumulating in the cavities.

The subsea capping stack shall include high temperature ram blocks and packers recommended by the ram manufacturer as the most appropriate design for closure on flowing conditions in a gas or oil subsea capping scenario.

To protect against gas migration past and permeation through the ram packing elements, the second vertical bore closure device should be a valve. The position of this valve shall be above the ram. Alternatively, a secondary cap (discussed below) installed on the top interface of the subsea capping stack can be used on designs incorporating two non-qualified ram closure devices.

Ram designs should include position indicators and ram locks.

4.4.5.1.2 Valve as a Closure Device

A valve used as the vertical bore closure device should be qualified to close on the maximum flow defined by the subsea capping stack BOD. In the absence of a qualified valve, a second valve should be used. Valves should be either a gate or ball valve and be designed in conformance with API 6A, API 17D, and API 17G.

Subsea capping stacks with valves should incorporate the capability for ROV overrides designed in conformance with API 17H and should include a visual position indicator.

Valves should be qualified for flow with solids and designed and tested to conform to API 6AV1 Class II for sandy service.

For subsea capping stacks with side outlet valves, the side outlet valves should be configured to "fail as-is" or "fail open."

4.4.5.1.3 Closure Device Qualification

A subsea capping stack should use closure devices that have been qualified to shut in on a flowing gas and a flowing oil incident well as applicable.

Closure device design and development verification meeting or exceeding the expected incident well conditions should be completed. These tests should be conducted at a component or unit level at a test facility capable of meeting the testing requirements. Analysis and/or subscale qualification testing may be performed in lieu of full scale flow testing.

Closure devices should be qualified to product specification level PSL 3G and be capable of closing and sealing on a stream of gas flowing at rates of 10-fps, 20-fps, and 30-fps as stated in API 14A, Section B.3.

Closure device qualification involves design and development verification and CFD analysis of the component design to determine reliability under the expected operational conditions. This design and development verification should include the following concurrent parameters:

- pressure,
- temperature,
- fluid velocity (see API 6AV1),
- abrasive content (see API 6AV1).

4.4.5.1.4 Redundancy of Closure Devices

Where qualification testing confirms reliability and suitability of the component to shut in an incident well flowing oil or gas, a single closure device may be used. In the case of subsea capping stacks incorporating a single qualified closure device, a documented risk assessment shall be used to justify the appropriateness of a single closure device for each configured flow path.

4.4.5.2 Secondary Cap

Following a successful subsea well capping operation, a secondary sealing cap (e.g. a blind hydraulic connector, blind flange, etc.) should be locked on top of the subsea capping stack. This secondary cap serves three main purposes:

- to provide an additional sealing mechanism to the subsea capping stack;

- to protect the subsea capping stack's main vertical reentry mandrel; and
- to provide long-term protection and sealing while the relief well(s) are drilled.

For these reasons, a secondary sealing cap that locks onto the top mandrel of the capping stack should be included as a component of the subsea capping stack system. If included, the secondary cap shall provide a means for checking pressure between the subsea capping stack main vertical bore sealing element and the secondary cap. It may also be necessary to include the capability to pump chemical below the secondary sealing cap to prevent the formation of hydrates or to vent trapped pressure.

4.4.5.3 Connectors

4.4.5.3.1 General

Materials and testing of all subsea capping stack connectors shall conform to the relevant sections of API 6A and API 17D.

4.4.5.3.2 Wellhead Connectors

The design of the subsea capping stack shall incorporate a hydraulically actuated wellhead connector that will interface to the incident well. The stack design should enable the surface replacement of the lower interface connector to accommodate various spacing requirements and to adapt the capping stack to the required connection type (mandrel or hub).

All wellhead connectors shall be designated by size (U.S. customary units only), pressure rating and the profile type of the wellhead (or other top connection) to which they will be attached. Connectors shall conform to maximum standard pressure ratings as per API 17G. As a minimum, the following connector loading parameters/conditions shall be analyzed and documented by the subsea capping stack manufacturer:

- internal and external pressure;
- pressure separation loads, which shall be based on worst-case sealing conditions (leakage to the largest redundant seal diameter shall be assumed);
- mechanical preloads;
- environmental loads;
- fatigue;
- vibration;
- mechanical installation (impact) loads;
- thermal expansion (trapped fluids, dissimilar metals);
- subsea capping stack loads;
- flowline loads;
- overpull;
- bending loads;

- angle from vertical;
- corrosion.

The subsea capping stack owner shall specify the loads/conditions for the wellhead connector and the wellhead connector OEM or stack manufacturer shall ensure through analysis that the connector is suitable for the conditions specified in the subsea capping stack BOD.

Hydraulically actuated connectors shall be capable of containing hydraulic release pressures of at least 1.25 times hydraulic RWP if normal operating pressure is inadequate. The manufacturer shall document both normal and maximum operating pressures. The connector design shall provide greater unlocking force than locking force.

Hydraulically actuated connectors shall be designed with a secondary release method, which may be hydraulic or mechanical. Hydraulic open and close control line piping shall provide a means to vent pressure and allow the secondary release to function.

All connectors shall be equipped with an external position indicator suitable for observation by ROV.

Hydraulic connectors shall be designed to prevent release due to loss of hydraulic locking pressure. This may be achieved by the connector self-locking mechanism (such as a flat-to-flat locking segment design) or backed up using a mechanical locking device or other demonstrated means. The design of mechanical locking devices shall consider release in the event of malfunction. The connector and mechanical locking device design shall ensure that locking is effective with worst-case dimensional tolerances of the locking mechanism.

Seal surfaces for connectors that engage metal-to-metal seals shall be inlaid with corrosion resistant material that is compatible with well fluids, seawater, etc. Overlays are not required if the base metal is compatible with well fluids, seawater, etc. Connector designs shall be in conformance with the standards of API 6A for flange connections and API 17G for other connections. Metal-to-metal sealing gaskets with a backup sealing profile, as per API 17D, are a recommended practice.

The subsea capping stack shall provide a means for testing all primary seals in the connector cavity to the rated working pressure of the subsea capping stack. This testing can be performed at any point after assembly for transit to the site and prior to being deployed.

The wellhead connector design should allow for easy, safe, and remote replacement of the primary seal via ROV. The retention method may be mechanical or hydraulic but should ensure that the seal may not be accidentally dropped. The connector design shall provide a means to inject or circulate hydrate inhibitor or hot water through the subsea capping stack connector to prevent hydrates from forming in the connector locking elements during installation of the capping stack onto an uncontrolled well.

4.4.5.3.3 Bodies, Flanges, and Other Connectors

All bodies, flanged end and outlet connections, and other connectors shall conform to their applicable specifications of API 6A, API 16A, API 17D, API 17G, and API 20E.

The requirements for studs and nuts for those used in end and outlet connections shall conform with API 17D. Flanges and gaskets shall be in conformance with API 17D.

4.4.5.3.4 Flowline Connector Standardization

Category 2 subsea capping stacks should provide an API standard flange interface on the flow spool outlets, downstream of any chokes. This provides a means to interface to a hydraulically actuated flowline connection system supplied by the associated containment system.

The subsea capping stack user should ensure that all of the proper connectors, jumpers, goosenecks, flexibles, hot stabs, and running tools are available for tie-back of the subsea capping stack to the user's intended containment system.

4.4.5.3.5 Diversion Outlet Connection

Connection components for diversion outlets should be of an industry standard size and rated working pressure as per API 17G. Diversion outlets should be placed in a symmetrical manner to minimize asymmetric thrust forces.

4.4.5.3.6 Fluid Injection (Kill Line) Inlet Connections

The fluid injection connection shall be designed to the same specifications as the diversion outlet to enable redundant functional use of this outlet.

4.4.5.3.7 Injection for Dispersants, Chemicals, and Hydrate Inhibitors

The design of all subsea capping stacks shall include chemical injection inlets. The quantity and placement of inlets shall be modeled by the subsea capping stack manufacturer to determine the chemical, dispersant, and hydrate inhibitor capacity, and to determine the inlet number and size and to identify optimum placement of inlets enabling efficient mixing.

4.4.6 Controls

4.4.6.1 General

Subsea capping stack control systems shall follow conventions of API 16D and API 17G to include industry best practices, commonality of interfaces, fast closure of barrier devices, and control of Category 2 capping scenario functions.

The subsea capping stack control system shall provide the fastest possible closure time for the applicable water depth of the main bore and diversion outlets. Surface control of a subsea capping stack with direct hydraulic power may be appropriate for subsea wells in shallow water. Hydraulic flow rates, umbilical size and handling, and overall hydraulic response (or lag) time may impair performance as water depth increases.

Items to consider when designing a subsea capping stack control system include, but are not limited to:

- water depth of intended operation;
- sufficient volumes to repeat component functions;
- function speed of closure devices;
- ROV access and visibility;
- flexibility to work within a variety of operating conditions (e.g. ability to shut in an incident well and the ability to control a well diverted to a containment system for up to six months);
- proximity to wellbore flow outlets (control system's vulnerability to debris, vibration, high flow rate discharge, etc. that could impair or disable the control system).

4.4.6.2 Control System Capacities

Subsea capping stack control methods shall have the energy capacity to function the well interface connector from fully locked to unlocked, twice without recharging. Once the stack is connected to the incident well, a hydraulic control system may be recharged.

The control system shall have the capacity to function closed all main bore and diversion outlet closure devices one time with at least 50 % capacity remaining, without recharging. Subsequently, a hydraulic control system shall have the ability to recharge or be recharged while subsea.

Alternative sources or types of hydraulic fluid accumulation may be designed for the subsea capping stack to reduce the size, weight, or support of the capping stack equipment. The control system may also be moved off the subsea capping stack to a less vulnerable location.

4.4.6.3 Closure Times

The main bore vertical closure device used in the subsea capping stack shall function closed as fast as possible within the component's recommended maximum closing speed and no slower than as specified in API 53. For the purposes of this document, emphasis on actuator closing time specifically focuses on reducing the period of time sealing components are exposed to high-velocity flow during shut-in operations. Electric and hydraulic lines leading to these functions should be sized to accommodate the specified closure times.

4.4.6.4 ROV Access

All subsea capping stack hydraulic functions shall be fitted with standard API 17H ROV hot stab receptacles. Functions that must meet API 53 timing requirements, such as rams used as a vertical main bore closure device, shall be fitted with API 17H 'Type C' (High flow) hot stab devices with external locking devices. These shall be clearly marked and labeled: a) on the equipment, and b) on the subsea capping stack drawings and documentation. Positive identification of the receptacle type and function shall be marked for underwater recognition, in conformance with API 17A and API 17H.

Subsea capping stack interface components and gauges must be located within normal view of the ROV camera.

Adequate "grab handles," in conformance with API 17H, should be made available to enable the ROV to remain stationary for engaging the interface item, even in adverse current conditions.

For functions intended to be mechanically operated by the ROV, the required operating torque should be in conformance with API 17H.

4.4.7 Materials

4.4.7.1 General

Equipment shall be constructed with materials (metallic and nonmetallic) suitable for its respective material classification in conformance with API 17D and API 17G.

The subsea capping stack owner shall specify the functionality, material class or designation, pressure rating, temperature ratings, flow rate limitations, and service environment (e.g. sour, corrosive) in the BOD, and the stack manufacturer shall in turn specify the materials of construction for pressure-containing and pressure-controlling equipment. Material classes AA–HH as specified in API 17D and API 17G, shall be used to indicate the material of those equipment components. Guidelines for choosing material class based on the retained fluid constituents and operating conditions are also given in API 17D.

4.4.7.2 Choke Materials

Choke assemblies shall be in conformance with API 16C.

4.4.7.3 Non-Metallic Materials, Coatings, and Greases

Nonmetallic materials (including elastomers and thermoplastics), coatings, and greases shall be suitable for the chemical environment, temperature, and pressure in which they will operate. Refer to API 17D for compatibility qualification with fluids they come in contact with.

Nonmetallic sealing materials, including elastomers and thermoplastics, shall be suitable for the chemical environment, temperature and pressure in which they will operate subsea as well as during specified preservation conditions.

Nonmetallic materials, coatings, and greases shall be shown to exhibit the following characteristics:

- resistance of elastomers to explosive decompression above 600 psi;
- compatibility with methanol (up to 90 %) and low dosage hydrate inhibitor;
- compatibility with dispersants;
- compatibility with non-continuous exposure to toluene and xylene;
- compatibility with amine-based corrosion inhibitors;
- compatibility with scale inhibitors;
- resistance to H₂S.

4.4.7.4 Sour Service

If a subsea capping stack has not been planned for a specific well with known parameters, it is a recommended practice to construct regional and global stacks with materials suitable for sour service. Subsea capping stacks constructed for non-sour service must be labeled "Not for Sour Service." For subsea capping stacks with a global perspective, all materials that come in contact with well fluids should meet the requirements of NACE MR0175 for sour service.

4.4.7.5 Arctic Considerations for Material Selection

All structural and mechanical components should be designed for the lowest expected preservation and testing temperature conditions. Charpy impact testing as per API 6A at or below the lowest expected temperatures should be performed on structural and mechanical components.

4.4.7.6 High Temperature Considerations for Material Selection

All metallic and nonmetallic subsea capping stack components should be constructed from materials designated for use on high-temperature wells as per API 17D and API 17G.

4.4.8 Designing for Transportability and Installation

4.4.8.1 Tie-down Point

A subsea capping stack and associated equipment shall be equipped with tie-down points to meet road, air, and offshore transportation tie-down requirements as specified by the capping stack purchaser/owner. All tie-down points

shall be load tested to 1.5 times SWL. All tie-down points shall be certified and have SWL markings. Special consideration shall be applied to airfreight where the aircraft owner has special requirements for tie-down. For example, some heavy-lift aircraft require equipment tie-down to meet up to 2.5 G acceleration. There may also be requirements to have special equipment shipping frames and baskets to meet the aircraft owner's requirements. It is the responsibility of the subsea capping stack owner to understand the rules and regulations concerning G-force tie-down requirements on surface and airfreight and to plan for these requirements.

As per API 17D and at a minimum, MPE or LP should be performed on all structural welds in the primary load path after proof load testing. Coatings shall not be applied to weld areas until the equipment has passed load testing and MPE/LP have been completed.

4.4.8.2 Lifting Equipment

Lifting pad eyes on all subsea capping stack equipment shall be designed in conformance with API 17D, Annex K, and DNV 2.7-3 including load testing of lifting pad eyes. Consider inspection and certification every nine months to provide a three months operational buffer when mobilized offshore.

Equipment should be supplied with permanent or removable bumper bars or transportation boxes/frames as appropriate for intended transportation and onshore/offshore handling.

4.4.8.3 Deck Loading and Shipping Stands

The supply vessel or the construction vessel handling the subsea capping stack may not have adequate deck loading capacity. A special shipping stand for spreading out the load on deck should be included in the subsea capping stack BOD and scope of supply.

Special shipping stands may also be required to transport the subsea capping stack by air and to an offshore location. The shipping stand shall meet aircraft requirements of maximum load per square area (e.g. metric ton per square meter) and have certified tie-down points to meet aircraft and vessel owner's requirements. The dimensions of the shipping stand may have to meet heavy-lift aircraft skid system dimensions. (One example is the Antonov AN-124, which may be set up with a skid system with a centerline to centerline dimension of 3144 mm, 2620 mm, or 2096 mm.)

4.4.8.4 High Angle Installation (> 2°)

As a minimum, the subsea capping stack should be capable of installation on an incident well that has an inclination of 2° from vertical.

A mechanical stress analysis shall be performed to ensure all components below the subsea capping stack can withstand the bending moments and any other forces imposed by offset installation.

4.4.8.5 Deployment and Recovery from Rig or Vessel

4.4.8.5.1 General

Subsea capping stack deployment methods should be considered during design and based upon vessel and rig specific limitation/capabilities with respect to the operating environment. Such issues to be addressed are:

- vessel mobilization (dockside/offshore);
- testing and preparation support needed;
- offshore transfer of capping stack (if applicable);

- onboard dynamic loads/outboard dynamic loads;
- splash zone loads;
- equipment relocating (carts, skids, etc.) onboard (if applicable);
- crane capacity and capability;
- height limitations;
- footprint for moonpool access (if applicable);
- ROV support needed of initial deployment;
- ROV tooling interfaces are checked and verified;
- key interfaces should be marked for easy ROV identification purposes of components and valve positions;
- sea-fastening of equipment/load control during lifting, offloading, and demobilization of capping stack;
- landing speeds (compensation effectiveness).

4.4.8.5.2 Running Tool Interface

The subsea capping stack deployment system should consist of a running tool or rigging that can be configured for deployment on drill pipe from a rig or on wire from a vessel. If the deployment system is not a universal design that allows for deployment on drill pipe and wire, two deployment systems should be developed to allow for flexibility. The deployment system should be designed to allow wellbore fluid flow through to assist with landing and latching operation. The deployment system running tool shall include an ROV activated connect/disconnect feature for easy retrieval and reinstallation as required.

The subsea capping stack running tool shall not create a restriction to flow in the vertical flow path of the incident well. Its design should minimize the impact of impinging flow.

4.4.8.5.3 Installation Aids

Landing a subsea capping stack onto a flowing subsea well has some similarities to landing a subsea tree onto a subsea wellhead and should include soft landing precautions to prevent equipment damage. However, additional soft landing precautions may be implemented to address the forces and motions associated with capping an incident well. To control these additional forces and motions vertical and lateral guidance systems may be required. This additional control is especially important for landing on a non-vertical well or if vertical access is impaired. The forces imposed by the incident well flow stream must be considered when designing the soft landing system. If additional lateral control is required, some options include:

- two or more guide wires attached to the well system guideposts (available on some subsea well systems) and threaded through corresponding guideline tubes on the subsea capping stack that can provide effective centering of the subsea capping stack when guidelines are tensioned;
- pull-down cables attached to the subsea capping stack run through pulleys attached to the well and back to a suitable active heave compensated winch on available service vessel that can provide effective vertical pull-down force to close the final gap between the subsea capping stack connector and the well mandrel.

4.4.8.6 Design for Environmental and Weather Conditions

The subsea capping stack should be designed with consideration of offshore weather and environmental conditions to enable the largest possible deployment and operability window.

Designs should mitigate the effects of the following:

- *waves*—height, wavelength, frequency, direction, period;
- *weather*—air temperature, wind speed, direction, period;
- *water*—depth, visibility, temperature;
- *current*—velocity, profile, direction;
- *seabed*—soil strength, depth profile, bearing capacity, topography, hazards, density, marine growth.

4.4.8.7 Vertical Intervention

Access to the vertical interface at the top of the subsea capping stack for post-installation well activities should be included in the BOD. These design considerations include, at a minimum, the strength of the interface component, strength of the subsea capping stack, strength of the damaged equipment below the subsea capping stack, strength of the wellhead, and the ID of the subsea capping stack's vertical bore. Load cases and a calculated mechanical and fatigue analysis should be performed by the operator for the incident well and used to determine the appropriateness of any vertical intervention plan. In addition, a documented risk assessment should be performed to evaluate the appropriateness, feasibility, and additional risks associated with any vertical intervention.

Post-installation vertical intervention activities could include installation of an additional subsea capping stack or temporary flow riser. For more extensive wire line or tubular interventions, an appropriate BOP shall be installed above the subsea capping stack and would require an appropriate mechanical and fatigue analysis and risk assessment of the complete stack-up. Wireline and tubular vertical intervention through a subsea capping stack is not a recommended practice as the primary function of a subsea capping stack is to shut in an incident well.

4.4.9 Design Load Analysis and Modeling

4.4.9.1 General

Design load analysis and fatigue modeling shall be performed by the subsea capping stack manufacturer to verify that the subsea capping stack can be deployed and operated as designed.

CFD analysis should be performed to confirm sufficient flow rate capacity of the subsea capping stack through the vertical bore and diversion outlets for land-out and individually for shut-in. Attention should be given to minimizing pressure differential (ΔP) and velocity across components in the flow path, thus reducing the potential for erosion during a shut-in sequence.

Analysis and modeling shall be performed to verify the subsea capping stack design is suited for its intended scope. These analyses shall be reviewed and revised any time there is a design change or modification to the subsea capping stack.

4.4.9.2 Failure Mode Effects and Criticality Analysis (FMECA)

FMECA shall be performed to identify and document potential failure modes and associated mitigation measures related to the subsea capping stack design. The FMECA should be reviewed and revised to reflect any repair, alteration, modification or component replacement, not to exceed every five (5) years.

4.4.9.3 Thermal Analysis for Hydrates

The heat transfer characteristics of the subsea capping stack should be modeled to support the design of the hydrate inhibition chemical injection system (i.e. number of inlets, flow rates required, location of inlets, and size of inlets).

4.4.9.4 Structural Analysis

Structural analysis shall be performed by the manufacturer to verify the subsea capping stack's design and capacity, using modeling/calculations, to be within material capability/grade, operational loads, and design factors. The analysis should consider the loads applied to the subsea capping stack through the life of the system. The load cases that should be considered include, but are not limited to, the following:

- fabrication and testing;
- preservation;
- maintenance and handling;
- offshore installation and retrieval (note limits to safe working loads in API 2A-WSD, API 17A, and API 17D);
- in-place/operation;
- transportation;
- bending loads;
- well pressure and applied pumping pressure; and
- structural loads associated with equipment interfacing to the subsea capping stack.

4.4.9.5 Fatigue Analysis

The subsea capping stack manufacturer shall perform fatigue modeling and calculations to verify that the subsea capping stack's design is within the capacity of the operational loads, design factors, and material grade. The analysis should consider loads applied to the subsea capping stack through the cumulative use of the system. The stack-up configurations that should be considered and performed in conformance with API 17G include, but are not limited to the following:

- flow containment riser attached to the top of the stack (global riser analysis);
- fatigue loads associated with installed equipment above the subsea capping stack; and
- flow containment equipment attached to the diversion outlets.

4.4.9.6 Vertical Bore Flow Analysis

A dynamic fluid flow analysis through the vertical bore shall be conducted to confirm the subsea capping stack can land and shut in an incident well.

4.4.9.7 Outlet Flow Analysis

The diversion of flow may create lateral forces on the subsea capping stack and existing well equipment. These forces should be analyzed and the subsea capping stack design verified to be capable of handling these forces. If the option exists to connect subsea flow lines to the diversion outlet, the load capacity of the outlet should also be verified.

Dynamic fluid flow modeling that considers limiting factors such as erosion shall be performed by the subsea capping stack manufacturer to determine maximum flow through each diversion outlet (with the vertical bore isolated). The design of the outlet(s) shall account for erosion and hydrate plugging during the diversion outlet closure sequence up to and including the final diversion outlet to be closed.

A dynamic fluid flow analysis considering erosion and any other limiting factors shall be performed to determine the maximum kill rate that can be achieved through each diversion line flow path of the subsea capping stack.

4.4.9.8 Centering and Uplift Force Modeling

As the subsea capping stack enters the well plume, centering, and uplift forces of the escaping effluent on the subsea capping stack should be modeled to optimize or modify stack designs and installation procedures. Features that may enable centering of the subsea capping stack include: funnels, guide wires, or other alignment devices.

4.4.9.9 Load Cases

4.4.9.9.1 General

Mechanical and fatigue analyses shall be performed on all components of the subsea capping stack by the stack manufacturer. Subsea capping stack load cases shall conform to the requirements of API 17D and API 17G, and include at a minimum:

- pressure (internal and external);
- bending load;
- torsion;
- hoop;
- impact; and
- any other combined loading such as snag loading of jumpers, umbilicals, flying leads, and connector release overpull load during cap recovery.

For subsea capping stacks interfacing to a riser-based containment system, the load cases and fatigue analysis shall conform to the requirements of API 17G, and include at a minimum:

- bending;
- tension;
- fatigue cycling;
- weak point due to drive off or drift off.

Verification of the design and load cases shall be performed through modeling and calculations. The design verification for subsea capping stacks should be in conformance with API 6A, API 16A, API 16C, API 17D, and API 17G as applicable. Subsea capping stack component ratings shall exceed the environment exposure and loads cases.

4.4.9.9.2 Installation and Retrieval

The subsea capping stack design analysis should address the methods of deployment, installation, and running tool interfaces including:

- deployment and retrieval loads;
- splash zone and salt water exposure;
- buoyancy and weight management effects on capping stack;
- well blowout plume exposure;
- dynamic loads and load amplification during deployment;
- centering and uplift forces.

4.4.9.9.3 In-place/Operation

The subsea capping stack design analysis should address operational loads during capping operations including:

- maximum discharge;
- wear resistance/exposure (solids/sand content, debris, etc.);
- sour service [hydrogen sulfide (H₂S)] exposure;
- CO₂ exposure;
- diversion of flow;
- flowline/jumper end loads.

4.4.10 Design Documentation

Documentation of designs shall be generated by the subsea capping stack manufacturer and at a minimum include methods; assumptions; calculations; qualification test reports; design validation requirements and analysis; and modeling reports. Design documentation requirements shall include, but not be limited to, those criteria for size, test, and operating pressures, material, environmental requirements, and other pertinent requirements on which the design is based. Design documentation media shall be clear, legible, reproducible, and retrievable. Design documentation retention by the manufacturer shall be for 10 years after the last unit of that model, size, and rated working pressure is manufactured, or as specified by the stack owner.

All design requirements shall be recorded in a manufacturer's specification document that shall reflect the requirements and design sections of API 6A, API 16A, and API 17D for their applicable component, the purchaser's specifications, and the manufacturer's own requirements.

4.5 Manufacturing

4.5.1 PSL 3/3G

The subsea capping stack components should conform to the requirements of PSL 3/3G as specified in API 6A. On the component level, a PSL 3G gas test shall be performed on all pressure-containing and controlling components of the subsea capping stack.

4.5.2 Hyperbaric Testing of Components

On the component level, subsea capping stack components should be validated at hyperbaric conditions as per API 17D, Annex L. API 17D provides guidance for hyperbaric testing including safety precautions.

4.5.3 Valve Specifications

Valve manufacture shall conform to the requirements of API 6A and API 17D.

4.5.4 Rams Specifications

Ram manufacture shall conform to the requirements of API 16A.

4.5.5 Thread Specifications

With exception of hydraulic tubing, use of threads in subsea capping stack designs shall conform to the requirements of API 6A.

Use of threads on handling tools shall conform to the requirements of API 7-1 and API 7-2 for rotary drill stem.

4.5.6 Hydraulic Tubing

Small-bore hydraulic tubing and connections, hydraulic couplers, end fittings, and couplers shall be manufactured in conformance with API 17D. Hydraulic lines leading to subsea capping stack functions need to be sized sufficiently large enough to accommodate the dictated closure times, especially those identified by API 53. Anti-vibration fittings are recommended for use on small-bore tubing that do not penetrate the wellbore.

Hydraulic tubing should be routed in a manner that does not impede ROV access or result in inadvertent damage. Hydraulic tubing should also be routed to avoid contact with the plume during installation onto the incident well.

4.5.7 Ports

All test, vent, injection, and gauge connections shall be manufactured in conformance with API 17D.

4.5.8 Subsea Gaskets

In the case of a damaged sealing surface on an incident well connection interface, sealing ring gaskets with resilient (nonmetallic) inserts may be used as a temporary means of obtaining a seal if approved by a MOC and risk assessment for the applicable operations. These gaskets should be tested with the connector only after the connector has been fully qualified with the appropriate metal-to-metal sealing gasket.

The subsea connector may also incorporate a hydrate seal. This seal, typically an elastomeric seal against the outside of the incident well attachment point, acts to deflect external hydrates and to prevent build up inside the connector.

The external pressure capacity, internal pressure rating, and temperature class of gasket seals on all connectors and connection points shall be provided by the subsea capping stack component OEM, along with information on available secondary and resilient insert gasket seals.

4.5.9 Qualification of Components

Subsea capping stack components shall be qualified to perform under the conditions set forth in the basis of design and according to the qualification requirements of API 6A, API 17D, API 17G, and API Q2. Subsea capping stack components shall conform to the requirements of API 6AV1 Class II for sand testing. Device qualification involves

design and development verification and analyses of the component design to determine reliability under the expected operational conditions. This design and development verification should include the following concurrent parameters:

- pressure;
- temperature;
- fluid velocity;
- abrasive content.

4.5.10 System Marking

Only subsea capping stack systems conforming with this recommended practice and intended for use to cap a subsea well shall be marked "API 17W." The system shall be marked with the following minimum information: part number, serial number, manufacturer name, or trademark. See API 6A for metallic marking and nameplate locations and requirements.

Equipment shall be marked in U.S. Customary units where size information is applicable and useful. The units shall be marked together with the numbers.

4.5.11 Quality Assurance/Quality Control

The quality control requirements for subsea capping stacks shall conform to API 17D and API 6A PSL3/3G.

For those components not covered in API 17D and API 6A, equipment-specific quality control requirements shall conform to the subsea capping stack manufacturer's written specifications. Purchaser and manufacturer should agree on any additional requirements.

Non-metallic materials (including elastomers and thermoplastics), coatings, and greases shall be suitable for the chemical environment, temperature, and pressure in which they will operate. Refer to Annex J in API 17D for compatibility qualification with fluids they come in contact with.

4.5.12 Testing Requirements

4.5.12.1 General

All mating structural components shall be tested in accordance with the manufacturer's written specification for fit and function using actual mating equipment or test fixtures.

Functional testing of subsea capping stack components and running/retrieval tools shall be conducted in accordance with the manufacturer's written specification to verify the primary and secondary operating and release mechanisms, override mechanisms, and locking mechanisms. Testing shall verify that the actual operating forces/pressures are within the manufacturer's documented specifications.

4.5.12.2 Factory Acceptance Testing

A comprehensive acceptance test program should be undertaken at the fabrication site to ensure that components have been manufactured in accordance with specified requirements. The test should be performed according to a predefined and approved procedure. Any failure should be repaired and analyzed to find the reason for the failure and/or result in a review of the calculated reliability of the system to determine whether the deviation can be accepted. Factory acceptance testing is generally a multi-tiered approach, involving individual component checks, subsystem checks (e.g. control system), interface checks, and unitized system checks. Modifications and changes to the equipment during testing and manufacture should be formally documented.

Factory acceptance testing may include, but not be limited to, the following items:

- individual component testing;
- assembly fit and function testing using actual subsea equipment and tools where possible;
- interface checks using actual subsea equipment and tools where possible;
- interchangeability testing;
- hydrostatic testing;
- valve seal checks at operating pressure;
- verification of piping code requirements;
- duration according to design code; and
- seal testing of end closures.

4.5.12.3 System Integration Test (SIT)

The SIT also provides opportunity for training of offshore operations personnel, installation personnel, maintenance personnel, etc., and offers the opportunity for all personnel to become familiar with the subsea capping system and its individual components.

When safe to do so according to vendor recommended practices, all ROV and component interfaces should be confirmed and functioned to ensure accessibility and operability during equipment SIT. If the ROV operator, tooling, or interfaces change, the need for another SIT or subset extended FAT should be evaluated.

System integration testing typically comprises the following activities:

- documented integrated function test of components and subsystems;
- final documented function test, including bore testing and leak testing;
- final documented function test of all electrical and hydraulic control interfaces;
- documented orientation and guidance fit tests of all interfacing components and modules;
- simulated installation, intervention mode operations, as practical, in order to verify and optimize relevant procedures and specifications;
- operation under specified conditions, including extreme tolerance conditions, as practical, in order to reveal any deficiencies in system, tools, and procedures;
- operation under relevant conditions, as practical, to obtain system data such as response times for shutdown actions;
- testing to demonstrate that equipment can be assembled as planned (wet conditions as necessary) and satisfactorily perform its functions as part of an overall system.

5 Use of a Subsea Capping Stack

5.1 Initial Actions

A major objective of early ROV assessment of an incident well is to assess and determine the best method for installing the subsea capping stack.

5.2 Equipment Notification and Callout

5.2.1 General

The incident and subsea capping stack owners shall have established equipment notifications and callout procedures.

5.2.2 Preapproval of Permits for Transportation

Prior to mobilization of the subsea capping stack, the incident owner should ensure the proper transportation plans have been prepared. Any special arrangements for air, road and/or sea transportation should be acted upon as indicated in the containment response plan, and the logistics plan. A load plan should be generated to a level where customs clearance can be executed with only minimal additional work.

5.2.3 Notification

In the event the subsea capping stack is necessary, the subsea capping stack owner should be notified as soon as possible. This notification should initiate secondary activities such as:

- confirming equipment readiness;
- verifying documentation is current and available;
- results of the initial ROV site condition survey; and
- attachment/interface options available.

The incident owner should provide the subsea capping stack owner the following incident well information:

- water depth;
- estimated bottom hole pressure;
- estimated maximum wellhead pressure;
- estimated wellhead temperature;
- known equipment limitations;
- status and information about the drilling program;
- key interface information;
- potential attachment options;
- approximate production composition; and
- ROV capability to facilitate the mobilization of appropriate tooling for the capping stack operation.

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5.3 Well Condition Assessment

5.3.1 General

An assessment of the well conditions should identify any specific limitations on the ability of the wellbore to contain full wellbore pressure including any limitations of the casing design, wear or damage to the casing, wellhead, or BOP stack, or any other factors that could cause failure of the wellbore upon subsea capping operations.

5.3.2 Site Assessment Survey

A site assessment survey's objective is to determine the status of the wellhead, BOP, and other components and to survey the immediate surrounding area to assess the following:

- the extent and nature of seabed debris;
- riser status and any obstruction to the wellhead, BOP, or LMRP;
- general damage to the wellhead, BOP, or LMRP;
- BOP configuration and functionality;
- status of BOP control system and whether BOP manipulation is practical and advisable;
- wellhead and BOP inclination;
- seabed features that may interfere with well capping;
- status of seabed currents and visibility;
- weather forecast and window for operation;
- location(s) of hydrocarbon release;
- most appropriate methods to deploy available subsea capping stack;
- possible interface connection points available for subsea capping stack.

5.3.3 Attachment Points

5.3.3.1 General

From information gained during the site assessment, the subsea capping stack can then be configured with the necessary connector or adapter to attach to the selected attachment point.

Depending on the actual condition of the well, the three most likely subsea capping stack attachment points to consider are indicated in Figure 3. The recommended order of preference for attachment points is this:

- top of the lower BOP mandrel—accessible if the LMRP is removed;
- subsea wellhead—accessible if the BOP is removed;
- tree—accessible if the BOP is removed;
- riser adapter above the LMRP—accessible if the marine riser is removed.

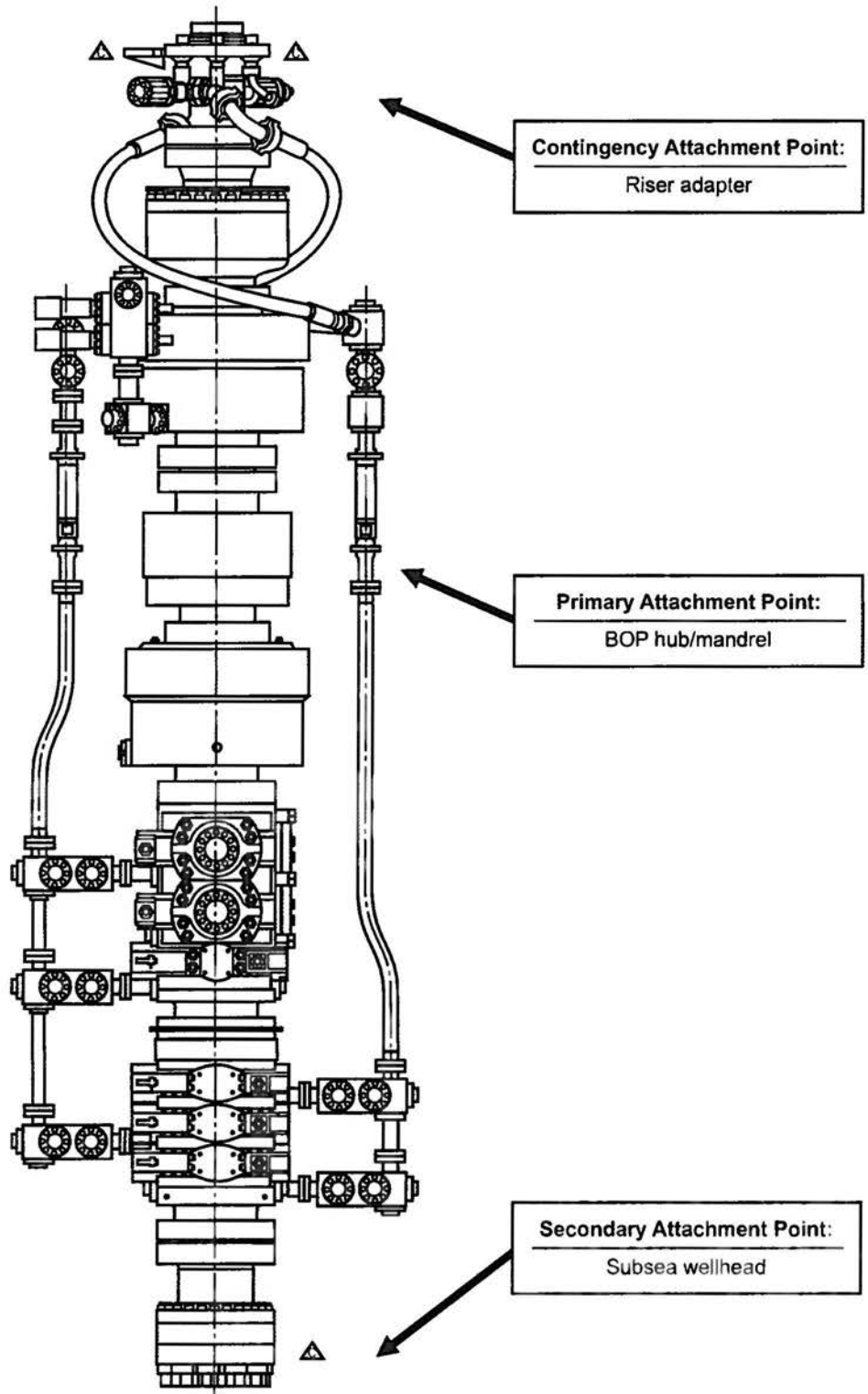


Figure 3—Example of Three Likely Subsea Capping Stack Attachment Points

The primary connection point used for the development of capping plans is the high-pressure mandrel on top of the lower BOP, accessible after removing the LMRP. Any secondary connection points should be evaluated in a contingency plan. Contingency attachment points to consider are the subsea wellhead after removal of the lower BOP and the riser adapter at the top of the LMRP, after removal of riser joint. Because of pressure limitations of the riser adapter (typically 6000 psi or less) this method is considered as a last resort contingency.

5.3.3.2 Lower BOP Mandrel

The preferred interface point for subsea capping stack operations is at the BOP mandrel profile where the LMRP connector attaches. This mandrel profile may be rated to 10,000 psi or 15,000 psi. Leaving the lower BOP in place may reduce the overall volume of hydrocarbons released into the environment by:

- reducing preparation time required to deploy a subsea capping stack;
- reducing the well discharge rate as a result of any partially closed elements in the lower BOP.

In the case of these connection points, the incident owner should anticipate a section of drill pipe could be left protruding out of the lower BOP mandrel following removal of the LMRP. Plans should be made to cut any obstructions protruding above the subsea capping stack connection point in order to provide clear access to the lower BOP mandrel. Special attention is required to prevent damage to the seal face.

The incident owner shall confirm through interference checks using drawings and pictures that the subsea capping stack is able to land on the top of the BOP hub/mandrel with no interference. Any interference resulting in subsea capping stack heading limitations should also be checked.

5.3.3.3 Subsea Wellhead (or Tree)

The reasons for considering installing the subsea capping stack directly onto the subsea wellhead may include:

- inadequate pressure rating of all the other potential subsea capping stack attachment points;
- significant damage to all the other potential subsea capping stack attachment points;
- compromised pressure integrity of the BOP equipment left on the wellhead due to well flow induced internal erosion; and/or
- there is no BOP present.

5.3.3.4 Riser Adapter

The subsea capping stack could also be installed on the riser adapter located above the lower flex joint of the LMRP after the attached riser has been removed. A rig specific, custom-made crossover is likely to be required for this option and is most likely be a component fabricated specifically for the failed BOP/LMRP. Typically, the riser adapter has a lower pressure rating than the other connection points.

This interface is not recommended as a primary interface point for subsea capping but should be retained as a contingency interface point should it provide the required pressure capacity. Selecting this option should be based on a risk assessment. It may be necessary to provide mechanical restraints to the flex joint to prevent it moving to max deflection when the weight of the subsea capping stack is installed.

This option is not available if the LMRP has already been disconnected as part of the initial rig emergency response to the blowout condition.

5.4 Deploying the Subsea Capping Stack

5.4.1 General

The following sections should be addressed when performing pre-deployment testing and installation of the subsea capping stack.

5.4.2 Deployment with a Rig

If a rig is to be used for installation of the subsea capping stack, the crane capacity needs to be investigated to determine if the subsea capping stack modules may be transported directly to the rig unassembled or as a completed assembly. The user should also determine the minimum amount of deck space and sea fastening requirements on the rig to carry out assembly and testing operations for the subsea capping stack.

A rig specific material handling plan should be prepared to describe handling methods, space and access requirements from receiving on rig until deployment in moonpool or over the side.

5.4.3 Deployment with a Multiservice Type Vessel

When considering vessel selection, the vessel winch or crane load capacity at water depth can be a significant limiting factor and dramatically affect the availability of capable vessels. The incident owner should compile a list of available vessels capable of deploying a designated subsea capping stack(s).

5.4.4 Pre-deployment Inspections

Pre-deployment inspections shall be performed in accordance with the subsea capping stack manufacturer's and incident owner's recommended procedures.

As a minimum, the subsea capping stack shall be visually inspected for the following:

- damage;
- leaks;
- valves, rams, and/or choke are in the correct position for deployment;
- hot stab dummies are in place as per the deployment plan;
- accumulators are charged for the water depth or as per deployment plan;
- the subsea capping stack control system is filled with the appropriate fluid volumes;
- the correct adapter has been installed on the subsea capping stack to interface with the planned attachment point;
- components used for shipping purposes have been removed; and
- a new ring gasket is inspected and locked in place (ring gasket selection shall be in conformance with API 17D).

5.4.5 Pre-deployment Interface Tests

Pre-deployment interface testing should include the verification of the ROV tools, interfaces, power and communication interfaces, hydraulic supply interfaces, and side outlet connections. See Table 1 for an example of a pre-deployment interface testing matrix. The subsea capping stack main bore pressure testing should be considered prior to deployment in the absence of a prior bore test performed during mobilization at the incident owner's discretion.

Table 1—Example of Pre-deployment Interface Testing Matrix

Interface Type	Testing	Acceptance Criteria
Bottom of subsea capping stack connector	<ul style="list-style-type: none"> — Landing subsea capping stack on mating test fixture. — Locking connector to test fixture. — Pressure test seal area. 	<ul style="list-style-type: none"> — Alignment during landing replicating as close as possible subsea installation. Attention should be paid to clearance of the subsea capping stack guide funnel as well as to clearance of the overall subsea capping stack to the debris field (i.e. BOP stack, LMRP, wellhead, etc.). — Allow for unobstructed full engagement of mating hub. — Verify diameter clearance and vertical (swallow) clearance. — Positive verification of lock by volume pumped and locking pressure, pressure test, or similar in addition to position indicator. — No visible leaks (see API 53 pressure test acceptance criteria).
Top of subsea capping stack interface	<ul style="list-style-type: none"> — Land and lock interfacing connector. — Pressure test seal area. 	<ul style="list-style-type: none"> — Alignment during landing replicating as close as possible subsea installation. — Allow for unobstructed full engagement of mating hub. — Verify diametrical clearance and vertical (swallow) clearance. — Positive verification of lock by volume pumped and locking pressure, pressure test, or similar, in addition to position indicator. — No visible leaks (see API 53 pressure test acceptance criteria).
Control system interfaces	<ul style="list-style-type: none"> — Engage hydraulic flying leads, including hot stabs and MQC plates. — Engage electric flying leads. — Install any remotely retrievable (not permanently installed) components such as transponders, acoustic communications. 	<ul style="list-style-type: none"> — Ensure clearance, positive latch, pressure integrity, and hydraulic continuity as appropriate. — Ensure clearance, positive latch, pressure integrity, electric continuity, and insulation resistance. — Ensure clearance, positive latch, and verify communication.
ROV interfaces	<ul style="list-style-type: none"> — Hot stab insertion. — Engage and manipulate all torque tool functions. 	<ul style="list-style-type: none"> — Engages completely to allow for actuation or manipulation as required.
Valve interfaces	<ul style="list-style-type: none"> — ROV interface check and mechanical manipulation. — Hydraulic function. 	<ul style="list-style-type: none"> — Function fully opens and fully closes, verify valve signature. — Ensure ROV clearance and manipulator clearance. — Verify torque values both running and break over.
Choke/pressure safety valve interface	<ul style="list-style-type: none"> — Interface. — Step function. — Pressure test. 	<ul style="list-style-type: none"> — Verify installation window diameter and swallow for remote installations. — Verify choke step positioning. — Verify pressure containment and pressure relief.

Table 1—Example of Pre-deployment Interface Testing Matrix (Continued)

Interface Type	Testing	Acceptance Criteria
Subsea retrievable chokes	<ul style="list-style-type: none"> — Land and lock interfacing connector. — Pressure test choke body. 	<ul style="list-style-type: none"> — Alignment during landing replicating as close as possible subsea installation. — Allow for unobstructed full engagement of mating hub. — Verify diametrical clearance and vertical (swallow) clearance. — Positive verification of lock by volume pumped and locking pressure, pressure test, or similar, in addition to position indicator. — No visible leaks (see API 53 pressure test acceptance criteria).
Subsea capping stack running tools	<ul style="list-style-type: none"> — Land and lock interfacing connector. — Emergency release mechanism. 	<ul style="list-style-type: none"> — Alignment during landing replicating as close as possible subsea installation. — Allow for unobstructed full engagement of connection and locking mechanism(s). — Demonstrated function of emergency quick release.
Side outlet interfaces	<ul style="list-style-type: none"> — Land and latch, lock, or make up. — Pressure test. 	<ul style="list-style-type: none"> — Verify installation window diameter and swallow for remote installations. — Verify latch/lock. — Verify latch/lock with no leaks.

5.4.6 Utility Requirements

5.4.6.1 General

Utilities required likely include potable water, compressed air, compressed inert gas, various engineered fluids, and electrical power. This section offers recommended practices for ensuring that all the utility equipment and services required to locally support the subsea capping stack equipment are considered in local subsea capping contingency plans.

5.4.6.2 Quayside and Deck Testing Utility Requirements

Pre-deployment testing of any subsea capping stack system requires the provision of local utility services such as potable water, compressed air, compressed inert gas, various engineered fluids, and electrical power. However, the system needs for each of these utilities must be confirmed with the subsea capping stack manufacturer. Similarly, all utility equipment minimum specifications must be confirmed with the subsea capping stack manufacturer and the local supplier(s) of this equipment should be included in the local capping contingency plan.

A HPU shall accompany the subsea capping stack to allow for function testing and pressure testing prior to deployment.

5.4.6.3 Offshore Utility Requirements

Service vessels and drilling rigs that may be used to deploy a subsea capping stack are typically able to provide the required utility services and equipment needed for capping stack deployment. However, the volume of compressed gas for pre-charging could exceed the normal volumes of compressed inert gas typically available onboard. The inventory of utility services and equipment available onboard all potential deployment vessels should be confirmed to be adequate for deployment needs of the subsea capping stack.

5.5 Operating Parameters

5.5.1 General

The sequence of operations to install and function the subsea capping stack defines when and in what order to function the elements. Operating the subsea capping stack begins with putting all the functioning elements into their respective positions for deployment. This section outlines the recommended practice for selecting the actual operating sequence for a given subsea well capping operation.

5.5.2 Uplift and Centering Force Effects on Installation

From flow modeling studies of subsea well flows impinging on a subsea capping stack during installation, the following general statements can be made.

- Forces acting on the subsea capping stack can be minimized by lowering the subsea capping stack to depth well outside of the incident well plume. Once near depth, move the capping stack laterally over the incident well. It is beneficial to enter the flow with the subsea capping stack lower connector within a minimal distance above the intended connection point.
- Once the subsea capping stack enters the flow, the flow induced forces acting on it increase with mass flow and velocity from the well but decreases with water depth, for a given flow rate. Hence, flow induced motion of a capping stack is more likely to be a critical concern when capping a high rate well in shallow water.
- After the subsea capping stack enters the flow (close to the flow exit point), and the flow begins to enter the bore of the capping stack, the forces acting on the capping stack aid in centering the capping stack over the flow.

5.5.3 Deployment and Recovery Considerations

Methods for limiting motions during overboarding, landing, installation, and recovery operations should be considered during planning. An environmental operating window should be developed to establish practical limits for conducting these operations.

Multiple heave compensation methods are available and should be designed and evaluated for appropriate installation parameters associated with each method and vessel. Examples include:

- vessel mounted active heave compensation;
- vessel mounted passive heave compensation;
- vessel mounted combined active/passive compensators;
- subsea active heave compensators;
- subsea passive heave compensators.

Recovery plans of the subsea capping stack should minimally address the following:

- flushing of hydrocarbons;
- loose/damaged accessories;
- potential for dropped objects;

- hazardous materials, including hydrocarbons, volatile organic compounds, sour gas, normally occurring radioactive material, etc.;
- trapped pressure;
- hydrates;
- marine growth;
- care, custody, and control of equipment.

During recovery of the subsea capping stack, an inspection and/or shipping stand should be available to enable a safe method of inspecting the connector sealing surfaces as well as to change out the connector gasket in the event of a redeployment. After recovery, hydrocarbons present or trapped within the containment cap frame or bores may spill or drip onto the vessel. A dedicated area should be set aside on the vessel deck for cleaning of the recovered capping stack.

5.5.4 Outlet Positions During Deployment and Land-out

The decision to land a subsea capping stack with the diversion outlets open or closed should be analyzed by the subsea capping stack manufacturer and owner so that a recommendation can be made to the incident owner. It has been commonly thought that the diversion lines should be run in the open position to minimize forces in the cap during land-out. However, in the case of subsea capping stacks, there may be circumstances where it is desirable to keep the diverter lines closed when the capping stack is moved into the flow and landed out. A flowing subsea well plume starts drawing water into the flow as soon as it exits the open well exit point depending on the geometry of the capping stack. Therefore, when the capping stack is first centered over the flow there is a chance that the capping stack diverter outlets will provide an opportunity for free gas from the well and seawater to mix and form a solid hydrate plug in one or more of the open diverter lines. In some applications, as a precaution to minimize the chance of plugging the open diverter lines with hydrates, subsea capping stacks may be deployed with all the diverter outlet elements closed.

Another potential reason to move a subsea capping stack into the flow and landing out with the diverter lines closed is when the diverter line outlets are asymmetrical it could result in creating a net lateral or rotational force on the capping stack, making it more difficult to control the motion of the capping stack during the land-out operation.

5.5.5 Vertical Outlet Closure Sequence

Before closing any vertical bore mechanical barriers, a check is made to ensure all the available diverter line outlets are fully open. This ensures that when the first main bore vertical closure device is closing the flow is diverted to minimize the erosion of the sealing surfaces. The first vertical main bore closure device should be closed as quickly as possible to prevent erosion of the closure device. Open diverter lines help minimize the resulting water hammer pressure surge on the well and subsea capping stack.

If the vertical main bore of the subsea capping stack contains more than one closure device, it is a recommended practice to first close the lowermost element above any diversion outlets. This treats the element as "sacrificial," enabling the final closure element to function under the lowest pressure differential environment.

It is the incident owner's responsibility to determine which vertical main bore element to close first. This depends on well specific conditions and the operating environment.

Depending on the location of the available diverter outlets relative to the first main bore element closed, additional main bore elements may not be sequenced to closed position until after closing any diverter outlets located between the available main bore closure elements. However, if the first main bore closure device is seen to be leaking, closure

of the second main bore element is priority, regardless of the location of any available diverter outlets relative to the second available main bore element.

5.5.6 Diversion Outlets Order of Closure

Once the first main bore closure device is closed and ROV camera inspection confirms the flow through the main bore of the subsea capping stack has stopped, the open diverter lines should be closed in an agreed logical sequence that minimizes any pressure increase to the wellbore.

5.5.7 Choke of Flow

If a choke valve is available as the outboard closure device, the chokes can be used to progressively shut off the flow. Otherwise, when actuating the diverter line closure devices, they should be closed as rapidly as possible to minimize any sealing surface erosion.

5.5.8 Monitoring Critical Parameters During Operation

After closing any closure device in the subsea capping stack, the pressure response should be carefully monitored. Any deviation from the expected pressure response range should be investigated as deviations could indicate integrity issues in the well system below the subsea capping stack and the barrier elements may have to be reopened.

5.5.9 In-service Inspections

In addition to monitoring pressure response as the capping stack elements are closed, it is also important to use the available ROV camera(s) to visually inspect the capping stack system for any damage (e.g. caused by flow related forces during installation) or fluid leakage from pressure-containing connections or elements. Periodic visual inspection and surveillance should be continued as long as the capping stack is in use.

5.6 Operating Personnel

5.6.1 Basic Competency

Subsea capping stack operations shall be performed by competent person(s). A competent person is one who has been trained and is knowledgeable of the subsea capping stack functions. A competent person has been qualified by the subsea capping stack manufacturer in accordance with the manufacturer's procedures and requirements. For additional discussion on competent personnel, see API 53.

5.6.2 Crew Drills

Subsea capping stack drills should be performed at a frequency determined by the well operator with the crews responsible for maintaining and operating the subsea capping stack. The purpose of these drills should be to maintain skills and to train new operators.

5.6.3 Personnel Records and Documentation

Installation, operation, and maintenance manuals furnished by the subsea capping stack manufacturer, and the manufacturer of any replacement equipment, should be readily available for training, reference, and use by the subsea capping stack owner, manufacturer, and operating personnel.

5.7 Logistics and Deployment Plans

5.7.1 Logistics Plan

Movement of the subsea capping stack from the base facility to location should be addressed in a detailed logistics plan. Part of the logistic plan is the logistics survey, which addresses getting the equipment to location. The logistics survey addresses details of airports and capacity to receive and service heavy-lift aircraft, customs clearance details to fast track response equipment through customs, availability of resources to handle and transport the subsea capping stack, capacity of roads, bridges and tunnels, road permit issues, and restrictions.

The logistics survey should address transportation details to ensure the subsea capping stack can be brought from the receiving airport to location without delay.

The subsea capping stack owner should assemble a detailed logistics plan addressing how to transport the subsea capping stack from point of pickup to the offshore site. Alternatively, the organization owning the capping stack may only provide the equipment and lifting gear at the warehouse preservation facility or at the nearest dock and may expect the incident owner to understand and handle all logistics and planning. Key issues to be addressed in a logistics plan are:

- air transport including heavy-lift aircraft type and quantity;
- tie-down drawings showing each tie-down point and SWL;
- over-flight and traffic rights;
- load planning with customs clearance details including description of equipment, serial number, part number, supplier, commercial value, Harmonized Tariff System codes, and Export Control Classification Numbers;
- intermediate stops;
- equipment shipping weight and size (note that weight using a certified load cell may be required);
- crane, trailer, and truck requirements and capacities.

5.7.2 Logistics

The incident owner shall prepare a load plan addressing the items being shipped including customs information and commercial invoices for customs clearance.

A pre-drill logistics survey should be jointly conducted by the subsea capping stack owner and the well operator. The logistics survey is required to ensure full understanding of how to get the capping stack from the preservation location to the incident location. Issues such as crane capacities, trailer sizes and capacities, permit loads, customs clearance out of country of preservation and into country of use, supply vessels and heavy-lift aircraft availability, airport and port capacities, intermediate stops, capacities of roads and bridges, tunnels, and size restrictions are some of the main issues being addressed in a logistics survey.

The logistics plan should address what third party technical personnel is required at the site of deployment.

5.7.3 Deployment Plan

The incident owner should assemble a system deployment plan addressing operations from receiving and handling at port of entry (airport or port) until the subsea capping stack is deployed from a vessel and installed. Key issues to be addressed in a system deployment plan are as follows.

- *Receiving Port of Entry (Airport or Port)*—Inspect the capping stack and associated equipment for handling and transportation damages.

- *Incident Owner's Receiving Port*—Inspect the capping stack and associated equipment for handling and transportation damages. Assemble the capping stack if applicable and prepare for offshore operations. Conduct function testing and pressure testing as recommended by the capping stack owner and the OEM.
- *Establish Crane Load Rating and Reach Requirements*—The incident owner should establish the crane requirements, considering dock placement, outrigger footprint, lift radius, and be especially aware of the restriction in lift radius.
- *Loading to an Offshore Vessel for Transport to the Incident Site*—A vessel load plan and deck layout plan should address vessel deck load capacity, the need for a special shipping frame, sea fastening, and the use of a marine surveyor to certify the vessel for voyage offshore.
- *Use of Crossover Connector*—A capping stack may be used with a crossover connector to mate with the correct hub type (e.g. H4, HC, or other type of hub). The detailed operating procedure shall address how this crossover is run (i.e. separately or already made up to the capping stack). Deployment together with the capping stack changes the deployment and must be thoroughly planned. Load calculations need to be revised if a cross-over connector is used.
- *Onboard Crane Handling*—Consider metocean and vessel heave conditions, vessel crane handling and overboarding capacity, and ability to land the capping stack subsea.
- *Capping Stack Operating Procedures*—Detailed operating procedures shall be developed based on the specific operational needs and the OEM's capping stack operating procedures.

6 Preservation, Maintenance, and Testing

6.1 Testing

6.1.1 General

The purpose of various testing programs on subsea capping stack is to verify:

- that all functions are operationally ready for deployment including all possible control systems;
- long-term pressure and valve torque trending for predictive maintenance purposes;
- the pressure integrity of the capping stack equipment.

6.1.2 Types of Tests and Test Criteria

6.1.2.1 General

Test programs shall be completed by the subsea capping stack owner and incorporate visual inspections, lifting gear recertification, function and pressure tests, maintenance practices, fluids testing for cleanliness and degradation, and operational mobilization drills.

Procedures for periodic function testing of subsea capping stack should cover all operational aspects such as equipment handling and installation tool operations; equipment stack-up/assembly; both primary and secondary valve and connector operations; inspection of seal surfaces; bore testing; preservation and control fluid change-out; paint and marking touch-up; ROV tooling interface and operation; rigging fit; inspection; and recertification. Procedures should be incorporated into acceptance tests, pre-deployment, installation and subsequent tests, operational mobilization drills, periodic operating tests, and maintenance practices.

Testing shall cover all operational aspects of the subsea capping system equipment, inclusive of controls.

Records shall be kept on test pressures, operating volumes, actuating torques, and how many times a particular component has been operated. These parameters are useful for predictive maintenance and equipment condition monitoring.

6.1.2.2 Testing Methodology

A testing document (see Table 2 and Table 3) shall be generated and maintained by the subsea capping stack owner. The subsea capping stack component OEM should be included in the development of the testing document.

The following minimum information shall be included in a testing document:

- testing requirements, including types of tests such as those listed previously in this document;
- testing frequency; and
- testing acceptance criteria.

Table 2—Example Routine Testing Schedule

	Monthly	Quarterly	Semiannually	Annually
Function Test Examples Include: — Actuating Systems — Operators and Actuators				
Interface Test Examples Include: — Connector — Control Systems — ROV Interfaces				
Pressure Test				
Valve Test				
Ram Test				
System Integration Test				

Table 3—Example Non-routine Testing Schedule

	Receiving (Post Refurbishment)	Pre-shipping	Incident Mob	At Shore on Vessel	Pre-splash
Function Test					
Pressure Test					
Valve Test					
Ram Test					
System Integration Test					

6.1.2.3 Test Recording

A test record system shall be developed, including written or electronic records and digital movies and/or digital photographs where practical, that provides a thorough description of each test. This record shall include the following minimum information:

- the equipment to be tested and its previous test record (dates, etc.);
- the test procedure objective(s) and detailed test procedure steps;
- the equipment required for performing the test;
- any prerequisites required before proceeding with the test;
- space for recording the date and time of the test;
- space for the equipment upper level part number and company specific unique identifier, where available;
- space for recording results, comments, and any punch list(s) resulting from the test.

6.1.2.4 Function Tests

6.1.2.4.1 General

A function test is the operation of a piece of equipment, or a system, to verify its intended operation within the design parameters. Function tests shall conform to the requirements of API 53. All components of the subsea capping stack shall be function tested to verify the component's intended operations. Function testing shall verify the fit, form, and function of the subsea capping stack. Function testing of the subsea capping stack shall verify installation, handling, and operating procedures.

Using function testing as an opportunity for personnel training is a recommended practice.

A function test, as well as a pressure test, of the subsea capping stack shall be performed following any disconnection or repair, limited to the affected component.

6.1.2.4.2 Function Testing of Actuating Systems

Prior to deployment, and during scheduled preventive maintenance testing, mechanical, and hydraulic control systems shall be function tested. The individual control stations shall be confirmed through system operation that shall replicate subsea operation.

6.1.2.4.3 Function Testing of Actuators

Prior to deployment, and during scheduled preventive maintenance testing, all actuators of the subsea capping stack shall be function tested. Function testing of these operators and actuators shall include testing of primary actuation operation, secondary override function, locking systems, and signature testing as appropriate.

All pressure-controlling devices configured for ROV operation should have a visual indicator to verify operability. These function tests shall also include rotary and linear override, where configured.

Manual, hydraulic, electric, acoustic, and ROV interface testing should be performed with all mating interfaces used for subsea capping stack function. Most of these involve ROV tooling or related equipment. See Table 4 for an example of an ROV interface testing table.

Torque, pressure, volume, number of turns, and other relevant data shall be recorded for comparison to values during subsequent operation.

Latching type components of subsea well control systems (chokes, pressure safety valves, control systems, hot stabs, jumper connectors, wellhead connectors, bonnet locking mechanism, etc.).

Emergency or secondary systems shall be function tested prior to deployment or as defined in subsea capping stack owner's planned maintenance (PM) program.

Table 4—Example ROV Interface Testing

Tool/Equipment Name	Physical Characteristics		Hydraulics		Electrical		Torque
	Dimensions	Weight	Pressure	Flow	Voltage	Current	
Chop saw							
Class 4 torque tool							
FLOT							
Super grinder							

6.1.2.4.4 Function Testing of Connectors

Prior to deployment, and during scheduled preventive maintenance testing, function testing of connectors shall be performed to verify lock and primary and secondary unlock, along with pressures and volumes for each function. Verification of connector lock can be confirmed by pressure test. In addition:

- verify connector lock/unlock position indicator function;
- verify function of the gasket retention mechanism;
- verify any other connector specific interfaces including flanged interfaces and top connection interfaces, as appropriate;
- verify correct seals installed;
- test hydraulic fluids for degradation and cleanliness.

6.1.2.4.5 Function Testing of Data Acquisition Systems

Prior to deployment, and during scheduled preventive maintenance testing, data acquisition systems shall be verified by reading and recording data and by verifying accuracy of information against the original design parameters.

6.1.2.5 Pressure Tests

6.1.2.5.1 General

Pressure testing acceptance criteria shall be in conformance with API 17D and API 53.

The pressure testing program conducted on the subsea capping stack as part of routine maintenance activities shall be outlined and performed at the stack's RWP. All pressure testing programs for the subsea capping stacks should be configured to allow for verification of all pressure retaining connections. This may include the need to use a blind flange, or equivalent, on top of the choke body to verify pressure integrity connection to the valves.

Pressure test programs for the subsea capping stack shall be generated by the subsea capping stack manufacturer and stack owner. Pressure testing documentation shall be maintained by the subsea capping stack owner.

A test report shall be issued following each maintenance and testing cycle and shall include the following as a minimum:

- executive summary;
- general description with reference documents and abbreviations;
- equipment list of equipment and consumables used during the service;
- visual inspection results;
- maintenance summary;
- overview of all tests, test results, failures, and repairs;
- maintenance summary of tooling package such as running tools, test stumps, choke handling tools, connectors and spare components, valve actuator tools;
- equipment status;
- lessons learned and recommendations for improvements;
- inspection photographs;
- pressure test and operating records;
- service company service reports.

Pressure tests conducted on the subsea capping stack during a subsea capping event shall be conducted to the RWP of the stack or to a pressure as determined by the incident well equipment, whichever is lower.

The subsea capping stack shall be pressure tested to a low pressure of 250 psi to 350 psi during any pressure testing program. When performing the low-pressure test, do not apply a higher pressure and bleed down to the low test pressure.

Valves that are required to seal against flow from both directions shall be pressure tested from both directions.

6.1.2.5.2 Pressure Test Frequency

Pressure tests on the subsea capping stack body shall be conducted as follows:

- during preservation as often as the capping stack manufacturer and owner (i.e. in accordance with the equipment owner's PM program or site-specific requirements) requires to provide confidence that the subsea capping stack is fit for service and available for callout or a minimum every 12 months; and
- after the disconnection or repair of any pressure-containing or pressure-controlling element in the subsea capping stack, limited to the affected component.

6.1.2.5.3 Hydraulic Chamber Pressure Test

A hydraulic chamber pressure test is the monitored and recorded application of pressure to any hydraulic operating chamber and associated control system elements such as:

- subsea capping stack ram cylinders and bonnet assemblies;
- hydraulic valve actuators;
- hydraulic connectors.

Hydraulic chamber tests shall be performed to the subsea capping stack manufacturer's RWP and in conformance with API 53.

Hydraulic chamber pressure tests shall be performed and charted as follows:

- rated working pressure test at intervals not exceeding one (1) year;
- when equipment is repaired or remanufactured;
- in accordance with the subsea capping stack owner's PM program.

6.1.2.6 Drift Tests

Drifting of the subsea capping stack should be performed and documented as a part of the capping stack acceptance criteria and following remanufacturing operations affecting the vertical bores. Drift testing shall be performed in conformance with API 6A or API 16A, where applicable.

Following acceptance pressure testing, performing a drift test on the capping stack through bore, rams, and hydraulic connectors and adapters in conformance with API 16A is a recommended practice.

6.1.2.7 Ram Tests

Where rams are used in a subsea capping stack, ram pressure, and function testing or verification shall be performed in conformance with API 16A.

Ram tests shall be performed, visually verified, and documented as follows:

- at minimum six month increments;
- when equipment is repaired or remanufactured; and
- in accordance with the subsea capping stack owner's maintenance program.

If so equipped, after closing the rams with hydraulic pressure, the closing pressure may be bled to zero and the ram wellbore pressure test can be conducted with only ram locks engaged.

6.1.2.8 Valve Tests

Where valves are used in a subsea capping stack, pressure and function testing shall be performed in conformance with API 6A. Gate valves shall be subjected to a function and pressure test that includes verification of any visual position indicator and determines the sealing capabilities of the assembly.

Valve tests shall be performed, visually verified, and documented as follows:

- at minimum six month increments;
- when equipment is repaired or remanufactured;
- in accordance with the subsea capping stack owner's maintenance program.

6.1.2.9 Choke Tests

A choke body pressure test (working pressure leak test) and choke function test shall be conducted at minimum one-year increments and following any repair or remanufacture of the choke.

Pressure testing of choke connections and seals may be performed in conjunction with the subsea capping stack bore test, with the choke in half open position and with a pressure cap or test line attached to the outlet line.

Choke seals and sealing surface should be visually inspected annually, just prior to pressure testing.

The choke shall be function tested annually over its full operating cycle just prior to pressure testing.

6.1.2.10 Test Fluids

Function and pressure tests may be performed using potable water as a test medium. If testing occurs in environments where freezing may occur, a mixture of water and glycol should be used to mitigate against freezing of the test fluid.

Control systems and hydraulic chambers shall be filled with and tested using clean control system fluids (to SAE AS4059) for the intended service and operating temperatures. All extracted fluids or returns shall be checked and filtered to SAE AS class 6B-F prior to use. It is recommend to add biocide and corrosion inhibitors to the test fluid due to potential of trapped fluids after a hydro test.

Control fluid used in the control system, accumulators, control lines, and BOP equipment operating chambers shall be carefully monitored for bacteria and solids content. An active bacterial prevention and monitoring program shall be maintained while the capping stack is in storage.

6.1.2.11 Test Pressure Measurement Devices

A calibrated test pressure gauge, or chart recorder, and/or data acquisition systems shall be used and all testing results shall be recorded and retained.

A pressure gauge for measuring the accumulator pre-charge pressure shall be available with a pre-charge/discharge kit.

Electronic pressure gauges and chart recorders or data acquisition systems shall be utilized within the manufacturer's specified range.

Electronic test pressure transducers and pressure measurement devices shall be calibrated per manufacturers requirements.

Calibrations shall be traceable to a recognized national standard (e.g. National Institute of Standards and Technology or American National Standards Institute).

6.1.2.12 Test Documentation Retention

The results of all subsea capping stack pressure and function tests shall be documented in paper or electronic format and retained for a period of five years.

Problems with the subsea capping stack that results in an unsuccessful function or pressure test and actions to remedy the problems shall also be documented and retained for a period of five years.

6.2 Maintenance

6.2.1 General

The long-term maintenance of a subsea capping stack is important to the preservation of equipment integrity and reliability, including:

- prevention of elastomer degradation and overall corrosion;
- ensuring the subsea capping stack is ready for mobilization when required, at any time with no need of additional maintenance or repair;
- performance trending critical to uncover any changes in the operability of the equipment.

The following minimum maintenance information shall be provided:

- maintenance requirements, including recommended intervals of inspection, maintenance, or replacement;
- disassembly and assembly instructions;
- proper operating techniques during maintenance activities; and
- assembly diagrams showing individual parts in proper relationship to one another.

6.2.2 Maintenance Schedule

The subsea capping stack shall be maintained at a frequency determined by the stack owner with input from the stack manufacturer (see Table 5). A service, maintenance, testing, and long-term preservation plan shall be generated and maintained by the stack owner.

Table 5—Example Periodic Maintenance Schedule

	Monthly	Quarterly	Semiannually	Annually
Visual Inspection Examples Include:				
— Corrosion Damage				
— Physical Damage				
— Paint Degradation from UV and Age				
— Verify Valve Positions				
— Check All Dummy Hot Stab Positions				
— Read All Gauges				
Lifting and Handling Equipment				
Lift Gear Certification				
Test Equipment				
Hydraulic Power Unit				
Calibrated Equipment				

6.2.3 Non-metallic Goods Maintenance

Non-metallic seal materials (i.e. seals, harnesses, etc.) have a limited service life. Given the unique long-term preservation requirements for the subsea capping stack, the planned maintenance program should include a non-metallic component replacement program. This program should be generated by the subsea capping stack manufacturer with input from the stack owner and component OEM. Compatibility testing between the non-metallic sealing materials and any proposed contacted chemicals should be conducted to determine behavior of the material.

Non-metallic sealing materials, including elastomers and thermoplastics, shall be suitable for the chemical environment, temperature, and pressure in which they will operate subsea as well as during specified preservation conditions.

A temperature and humidity (climate) controlled environment should be considered for storing capping stack spare parts as a method of preventing corrosion and increasing the service life of spare parts.

6.2.4 API End Connections Maintenance

6.2.4.1 Critical Sealing Areas

Protective coverings and coatings should be used on all critical sealing areas such as open faced, studded flange face and hub connections along with other end connections. Protective coverings may be removed to allow for inspection. All protective coverings should be reinstalled after inspection and prior to preservation.

6.2.4.2 Ring Gaskets

Metal ring gaskets should not be reused for operational purposes. Metal ring gaskets may be reused for pressure testing, such as simulated wellhead pressure tests or tests at surface prior to deployment, but shall be documented and discussed with the subsea capping stack owner.

6.2.4.3 Closure Bolting

Closure bolting should be cleaned and inspected for damage. A lubrication and torque record shall be maintained for all closure bolting.

Following cleaning for inspection, and where the manufacturer specifies, ensure specified lubrication is applied to closure bolting before use where applicable.

Each lubricant possesses a unique friction factor that should be matched to the correct application of tightening torque—this information should be available from the manufacturer of the lubricant or the equipment.

6.2.5 Cleaning and Coating

6.2.5.1 General

Rams and sealing elements should be removed and the internal capping stack body/cavities thoroughly washed, inspected, and coated with a corrosion inhibitor, in accordance with the subsea capping stack maintenance schedule.

When storing subsea capping stack replacement parts and assemblies, the parts and assemblies shall be maintained with a protective coating. These coatings, if they affect system operability, should be removed immediately prior to deployment subsea. A limited number of solvents effectively remove protective preservation coatings.

6.2.5.2 Repair of Coatings

Repairs to coatings shall be in accordance with the subsea capping stack manufacturer's recommended practice.

6.2.6 Repair and Remanufacture of Subsea Capping Stack

6.2.6.1 General

Repair and remanufacture of subsea capping stack shall conform to the applicable sections of API 6A and API 16A for respective equipment. Alternate sources should be qualified to demonstrate the acceptability of their components prior to use.

During the performance of preservation and maintenance activities, the subsea capping stack experiences normal wear and tear requiring repair. Such activities may include paint touch-up, replacing rubber O-rings, retainer pins, and shear pins, etc.

6.2.6.2 Repaired or Remanufactured Components

Repaired and remanufactured assemblies shall be designed for their intended use by industry approved and accepted practices that conform to their applicable API standard. Repaired and remanufactured components must conform to the design, dimensional, test, and manufactured specifications of the original component.

6.2.7 Quality Control and Management

6.2.7.1 General

Quality control during the manufacture of all subsea capping stack components shall be in conformance with API Q1.

6.2.7.2 Planned Maintenance (PM) Program

A PM program shall be generated and maintained by the stack owner. These plans shall include periodic maintenance activities such as tests, operating trend collection, and recommended spare parts lists.

The subsea capping stack owner, or the party responsible for performing maintenance, shall complete a field performance report of equipment that has recognized anomalies. This report should be used to identify equipment that requires further maintenance or repairs. See Table 6 for an example of a field performance report.

The manufacturer's installation, operation, and maintenance manuals, furnished by the subsea capping stack manufacturer, and the manufacturer of any replacement equipment, shall be available for reference and use by maintenance personnel.

Electronic and/or hard copy records for maintenance, repairs, operating performance, and remanufacturing performed for the subsea capping stack shall be maintained on file at the preservation facility and until the equipment is permanently removed from service.

Electronic and/or hard copy records of remanufactured parts and/or assemblies shall be readily available and preserved at the preservation facility.

Table 6—Subsea Capping Stack Field Performance Report Example

Number	Description	Comments	Initials/Date	FPR #
1	Ex., Needle valve excessive torque	Ex., Found corrosion in needle valve	/	#1
2			/	
3			/	
4			/	
5			/	

6.2.7.3 Traceability

Parts and material shall be traceable in conformance with API 16A.

6.2.7.4 Manufacturer's Product Alerts/Equipment Bulletins

Copies (electronic or paper) of equipment manufacturer's product alerts or equipment bulletins for the subsea capping stack shall be maintained by the subsea stack owner as per API 53.

6.2.8 Maintenance Records and Documentation

6.2.8.1 General

A manufacturing record book shall be required at the time of manufacture for the subsea capping stack. The book shall, at a minimum, include records of FAT; SIT; pressure tests; non-conformance reports (NCRs); test charts; welding procedures and specifications; Material Traceability Record (MTR); inspection records; test failures; repairs; certificate of conformance; torque tests and charts; electric continuity tests; weight record sheets; flushing and cleanliness records; NACE specifications; and assembly records.

The subsea capping stack owner shall be responsible for maintaining documentation requirements for the life of the subsea capping stack. Should ownership be transferred, the documentation shall also be transferred to the new owner.

Electronic and/or hard copies of all applicable standards and specifications referenced herein, relative to the subsea capping stack shall be readily available at all times.

The subsea capping stack manufacturers' operating and maintenance documents, subsea capping stack product bulletins, subsea capping stack owner PM programs, and operating experiences shall be incorporated into the site-specific procedures.

Material safety datasheets (MSDS or SDS) shall be available for all chemicals (e.g. fluids, solvents, greases, etc.) used in association with the subsea capping stack.

6.2.8.2 Maintenance and Repair History and Problem Reporting

A maintenance and repair historical file shall be retained by serial number or unique identification number for each major piece of subsea capping stack. Repairs shall become a permanent record in the database for the assembly. The maintenance and repair historical file shall follow the stack when it is transferred. Equipment malfunctions or failures shall be reported in writing to the subsea capping stack manufacturer.

The subsea capping stack owner shall maintain a log of subsea capping stack failures. The log shall provide a description and history of the item that failed along with the corrective action.

Details of the subsea capping stack, control system, and essential test data shall be maintained for as long as the equipment is in service.

6.2.8.3 Traceability Record Report

A traceability report shall be prepared according to API 16A in which all serialized and individual heat-traceable parts are listed as traceable to the assembly (e.g. assembly part number, serial number).

6.3 Inspections

6.3.1 General

The long-term preservation and maintenance of a subsea capping stack should include an inspection plan to ensure readiness. The use of trending analysis and associated record keeping should be used to identify changes in the operability of the equipment.

The subsea capping stack owner and manufacturer shall develop an inspection schedule for the subsea capping stack in order to ensure it is maintained in a constant state of readiness. Operability and integrity can be confirmed by function and pressure testing as discussed in the preceding sections of this document.

The frequency of inspection shall be based on equipment preservation conditions and may change based on trends and experiences from the service and maintenance program. The inspection schedule shall include type and level of inspections, services, and tests to be performed. Inspections shall be performed by a qualified competent person(s). See 6.5.1, Basic Personnel Competency.

6.3.2 Pre-shipping Inspections

The subsea capping stack shall undergo a pre-shipping inspection program that has been documented by the subsea capping stack owner.

The inspection shall ensure the subsea capping stack is ready to be handled and shipped, that fluids are drained, if necessary, and that all required ancillary equipment is also ready for shipping.

It is a recommended practice that the subsea capping stack should be in a state of readiness at all times.

6.3.3 Receiving Inspection

6.3.3.1 At the Preservation Facility

Upon receipt of the subsea capping stack at the long-term preservation location, the subsea capping stack shall undergo a receiving inspection program that has been documented by the subsea capping stack owner.

At a minimum, the receiving inspection should:

- inspect for transportation damages and damages that may have been caused by incorrect handling;
- inspect for completeness and condition of delivery;
- inspect and confirm that delivery is according to the scope of supply;
- ensure that each individual subsea capping stack component is marked with a serial number, or unique identifier, according to the quality plan.

Receiving inspections should also be performed following repair or remanufacture of equipment at an offsite facility. Following remanufacturing, the equipment data book should be inspected to verify that all relevant remanufacture documents have been incorporated into the data book.

6.3.3.2 At Quayside

Following shipment from the preservation location, the subsea capping stack should undergo a predetermined receiving inspection program quayside to assure its readiness to deploy. The inspection shall be according to pre-developed receiving inspection procedures and should include as a minimum:

- inspection for transportation damages and damages that may have been caused by incorrect handling; and
- inspection for completeness of delivery including hydraulic power unit, operating fluids, running tools, tools and spare parts, handling slings and shackles, etc.

6.3.4 Certificate of Conformance

A certificate of conformance, verified by a third party, stating compliance with the BOD requirements and the applicable specification or standard should be issued by the subsea capping stack manufacturer in the form of a certificate including the data book with a completed and signed FAT and should be provided to the stack owner.

6.4 Preservation

6.4.1 General

Appropriate long-term preservation of the subsea capping stack includes practices to ensure that the equipment is maintained in a constant state of readiness.

A long-term preservation plan shall be generated by the subsea capping stack manufacturer with input from the stack owner.

Selection of the preservation location shall, at a minimum, include the following criteria:

- security and protection of all subsea capping stack components;
- facility height to allow use of a crane for equipment handling;
- maintenance requirements;
- function and pressure testing requirements;
- long-term preservation requirements; and
- transportation requirements to base/quayside/airport.

6.4.2 Protection from the Environment

6.4.2.1 General

The recommended practice is to store the subsea capping stack indoors. If outside preservation is the only option, the facility and location should avoid flooding, UV, dust, rain, and ice, but only inside preservation provides a measure of protection against extreme heat, cold, and unexpected weather events. Tarps may be used indoors as an effective measure against dust, but tarps used outdoors can trap moisture and lead to corrosion.

All inlet and outlet connection flange faces, and ring grooves should be protected with durable covers or purpose built pressure caps or trash caps to allow the system to be filled with preservation fluid, when recommended by the subsea capping stack owner for long-term preservation. A non-sealing protective approach is recommended for these applications.

If subsea equipment is stored, transported, or tested at temperatures outside of its temperature rating, the manufacturer should be contacted to determine if special preservation, transportation, or surface-testing and preservation procedures are recommended. Subsea capping stack maintenance and preservation documentation shall reflect any such conditions and requirements.

6.4.2.2 Preservation of Rubber and Elastomeric Materials

This section describes the recommended practice for preservation conditions and the maximum acceptable storage life permissible for rubber and elastomeric products. The environmental conditions upon which they are stored should determine the overall maintenance strategy. These requirements shall be applicable to all custom molded rubber and elastomeric materials. The physical properties of most rubber and elastomeric materials change during storage and ultimately become unserviceable because of aging. Some examples may include excessive hardening, softening, cracking, or some other surface degradation. The amount varies with time, environmental conditions, and mechanical stress.

Any rubber goods or elastomeric components found to be outside the manufacturer's recommended expiration date shall be discarded and prohibited from use in subsea capping stacks.

Elastomeric materials should be stored in ambient temperature conditions as per OEM recommendations. Temperatures should not exceed 100 °F (38 °C), otherwise seek climate controlled environments.

- *Exclusion of Air (Oxygen)*—Elastomers should be stored in a dry space. Use airtight containers when possible to protect against circulating air. The relative humidity shall be such that given the variations of temperature in preservation, condensation does not occur. If the elastomers are not stored in sealed moisture proof bags, the relative humidity of the atmosphere in storage shall be less than 75 %. If polyurethanes are being stored, the relative humidity shall be less than 65 %.
- *Exclusion of Contamination*—Elastomeric seals shall not be allowed to come in contact with liquid or semisolid materials or their vapors at any time during preservation unless these materials are by design an integral part of the component or the manufacturer's packaging.
- *Exclusion of Light (Particularly Sunlight/UV Rays)*—Individual preservation bags or black plastic wrapping offer the best protection as long as they are UV resistant. It is advisable that windows of preservation rooms where elastomers are stored in bulk be covered with a red or orange coating. DO NOT store in direct sunlight even if wrapped, as overheating will result.
- *Exclusion of Ozone Generating Electrical Devices*— Preservation rooms shall not contain any equipment that is capable of generating ozone (e.g. mercury vapor lamps, high voltage electrical equipment giving rise to electrical sparks, or silent electrical discharges). Combustion gases and organic vapor shall be excluded from preservation rooms as they may give rise to ozone via photochemical processes.
- *Exclusion of Radiation*—Precautions shall be taken to protect stored articles from all sources of ionizing radiation.
- *Tensile and Compressive Stresses*—Store rubber parts in a relaxed position to reduce deformation.
- *Exclusion of Contact with Metals*—Elastomeric seals shall not be stored in contact with metals (except when bonded to them) but shall be protected by individual packaging.
- *Exclusion of Contact Between Different Elastomers*—Contact between different elastomers and elastomers of different seals shall be avoided.
- *Independent Lighting*—The rubber goods preservation area should be equipped with independent lighting switches from the container work area and be kept off as much as possible.

6.4.2.3 Preservation Fluids

The subsea capping stack manufacturer and component manufacturer should provide documented recommendations on long-term preservation to be used. The use of a water-based hydraulic preservation fluid designed specifically for long-term preservation of subsea hydraulic systems should be used.

Shelf life of control system fluids, including long-term preservation fluids, should be inspected periodically and the fluids replaced if found to be ineffective. Fluid storage containers should be circulated and filtered on a scheduled basis to prevent disintegration and particle growth. Note that some defoamers are removed from the fluid during the filtration process.

6.4.3 Long-term Preservation of Spare Parts

6.4.3.1 General

The term spare parts refers to replacement components and assemblies.

The OEM should be consulted to provide guidance on the expected life cycle of spare parts.

The subsea capping stack owner shall develop a spare parts philosophy and a spare parts and consumable delivery plan. The spare parts philosophy may vary depending on the type of capping stack (e.g. rams vs. gate valves).

The spare parts philosophy shall consider the consequences of capping stack out of service time by not having critical spare parts and components available. Some spare parts may be unique and have several months delivery time. It is, therefore, critical that the subsea capping stack owner has the overview of the spare parts supply situation.

The subsea capping stack owner shall identify critical long lead time spares prior to taking receipt of the subsea capping stack. Identified critical long lead spare parts shall be stored with the subsea capping stack.

The replacement frequency of rubber and elastomeric materials, including an evaluation of aging, shall be included in the spare parts delivery plan.

Spare parts shall be designed for their intended use by industry approved and accepted practices.

If spare parts and assemblies are acquired from a non-OEM, the parts and assemblies shall be equivalent or superior to the original equipment and fully tested, design verified, and supported by traceable documentation in conformance with relevant API documents.

6.4.3.2 Spare Parts preservation Requirements

The preservation requirements of spare parts shall be predetermined and agreed upon by the subsea capping stack owner and manufacturer. The equipment manufacturer shall be consulted regarding spare parts (e.g. connectors, ram bodies, gate valves) preservation requirements.

Parts that are sensitive to temperature or humidity, or have a limited shelf life, shall be preserved in a controlled environment as mentioned previously.

Preservation plans should be in place to ensure readiness of all spare parts. It is essential that the preservation and maintenance contractor is responsible for, and has the overview of, the spare parts inventory control.

Spare elastomeric components shall be stored consistent with elastomeric preservation guidelines discussed previously.

When storing subsea capping stack replacement parts and assemblies and related equipment, the parts and assemblies shall be coated and maintained with a long-term protective coating to prevent corrosion.

6.4.4 Retention and Preservation of Records and Documentation

6.4.4.1 General

The subsea capping stack owner shall be responsible for documentation requirements and shall retain all materials as long as the equipment remains in service, unless otherwise noted.

The recommended practice is to store electronic and/or hard copies of all documentation in two locations, one of which is in close proximity to the equipment and the other at a secure, offsite location.

6.4.4.2 Manufacturer's Product Alerts/Equipment Bulletins

Copies (electronic or paper) of equipment manufacturer's product alerts or equipment bulletins for the subsea capping stack shall be maintained at the preservation facility. The subsea capping stack owner shall have procedures in place to capture alerts and bulletins.

6.4.4.3 Installation, Operation, and Maintenance Manuals

The manufacturer's installation, operation, maintenance, and long-term preservation manuals for each individual assembly shall be available at all times for all subsea capping stack assemblies and copies should accompany the subsea capping stack when shipped.

Operation and maintenance manuals should contain the following:

- descriptive text with adequate assembly drawings;
- sequence drawings;
- schematics;
- P&IDs;
- weight charts showing dimension of all equipment;
- parts lists; recommended spare parts lists;
- assembly and test procedures;
- inspection, maintenance, and repair procedures;
- offshore installation and operating procedures;
- preservation procedures;
- transportation and sea-fastening procedures;
- digital photos; and
- all other pertinent information required by any referenced specification within this recommended practice.

Operation and maintenance manuals should also contain related data books from any and all vendors and sub-vendors.

Hard copies of all manuals, including equipment drawings, manuals, and bulletins containing torque specifications, specifications, and bills of material, shall accompany the subsea capping stack to the incident site to identify the equipment and to assist with procuring correct replacement parts.

Modifications, alterations, or adjustments from the original design or intent of the subsea capping stack and control system shall be documented through the use of a MOC system.

6.4.4.4 Shipping and Receiving Documents

The following shipping/receiving documentation, as a minimum, should be indicated in the logistics plan and provided at time of shipment to the long-term preservation facility:

- certificate of conformity;
- punch list closeout certificate;
- packing lists;
- bills of lading;
- MSDS (or SDS) sheets;
- For international shipments that require use of timber, International Standards for Phytosanitary Measures ISPM No. 15; and
- procedures for shipping, preservation, and preparation for use.

6.4.4.5 Equipment Data Books

The OEM shall develop design data books for the major components of the subsea capping stack and provide them to the stack owner.

Design data books should contain descriptive text with drawings, P&IDs, calculations, analyses, schematics, copies of any software (including revision history), and all other pertinent information required by any referenced specification within this standard and by the subsea capping stack owner.

Equipment records (electronic or hard copy), manufacturing documentation, NACE certification, FAT reports, and documentation of all repairs shall be retained as long as the equipment remains in service.

Copies of the manufacturer's equipment data book shall be available for review for as long as the equipment is in service or preservation.

6.4.4.6 Independent Certification

The certification of pressure-containing devices used for subsea capping operations is recommended to verify and document that the equipment condition and properties are within the updated acceptance criteria, as well as recognized codes and standards.

The extent of the recertification scheme to be followed shall be agreed upon by the subsea capping stack owner and manufacturer.

Copies of the independent certification shall be retained for as long as the equipment is in service or preservation and shall be available for review.

6.4.4.7 Test Procedures and Test Reports

Testing after major modifications or equipment weld repairs shall be performed according to the subsea capping stack manufacturer's written procedures.

The subsea capping stack and its components manufacturer's procedures for installation, removal, operation, and testing of all subsea capping stack shall be available and followed.

Pressure and function test reports shall be developed by the subsea capping stack manufacturer, recorded, and retained for five years.

6.5 Testing, Maintenance, Inspection, and Preservation Personnel

6.5.1 Basic Personnel Competency

Maintenance, inspection, testing, repair, and refurbishment of subsea capping stack shall be performed by a competent person(s). A competent person is one that has been trained and is knowledgeable of the subsea capping stack and functions. Said person should be qualified in the equipment manufacturer's training program and in accordance with the manufacturer's procedures and requirements.

6.5.2 Storage Facility Crew Proficiency

The proficiency with which crews respond to an event requiring the subsea capping stack is as important as the operational condition of the equipment. All designated subsea capping stack preservation facility personnel should be familiar with the subsea capping stack components and be capable of reacting quickly and efficiently to potential situations requiring their use.

The subsea capping stack owner should develop a preservation facility crew drill plan and schedule. When the desired proficiency is attained, periodic drills should be continued to maintain performance.

Drills should be documented and executed to identify opportunities for improvement. Follow up on problem areas identified in the drills should be completed and documented.

Periodic tabletop and live exercises/drills should be planned, scheduled, and executed to ensure crew competency and availability. Examples of drills include:

- emergency response notification;
- equipment shipping, customs clearance, and transportation to port of operation;
- equipment assembly, testing, and deployment;
- simultaneous operations;
- communications;
- ICS integration;
- any other drill requirements as per the local government and regulatory agencies.

6.5.3 Records and Documentation

Maintenance manuals, furnished by the subsea capping stack owner, should be readily available for training, reference, and use by maintenance personnel.

Training records and certificates should be retained at the equipment preservation location or at a separate offsite location for as long as the subsea capping stack is in service or preservation. Applicable local regulatory requirements for retention periods should be followed.

Annex A (informative)

Subsea Well Capping Contingency Procedures

A.1 General

The incident owner should address contingency procedures as part of the subsea capping plan and should consider performing a risk assessment before implementing any situation specific contingency operations.

A.2 Debris Removal

A.2.1 General

The incident owner's approach to debris removal should be based upon using competent and proven industry service providers. Debris that may obstruct capping operations include debris on the seafloor such as riser or drill pipe, the drill rig sunk on the seafloor possibly on the wellhead, or a severely damaged drill rig at surface. Prior to running the subsea capping stack, the incident owner shall have a written procedure addressing removal of the subsea debris. The incident owner should have procedures covering the most likely debris removal scenarios on file prior to any well control event.

The objective is to remove any debris and failed equipment surrounding the wellhead and failed BOP to allow well capping activities to be safely and efficiently executed by reconnecting back to an adequate pressure retaining component.

The debris removal strategy may be to remove riser and other debris from the immediate vicinity of the wellhead and to relocate the debris on the seabed remotely from the wellhead.

During a deepwater incident, possible scenarios involving a failed marine riser may include the following.

- A significant amount of riser has fallen to the sea floor, the riser is still connected to the LMRP, but bent over, and several pieces of riser are also lying against the BOP stack. The BOP and wellhead is vertical.
- The riser has parted just above the BOP stack, at the flex joint, due to high bending loads imparted to it, as the disabled drill rig has drifted off location at surface. The BOP and wellhead may be deflected from vertical.
- The riser has been cut or disconnected just above the LMRP, but the LMRP remains connected to the BOP stack. The BOP and wellhead are vertical.
- It may also be possible that the LMRP has been successfully hydraulically disconnected, either by activation of the drill rig emergency disconnect sequence or by subsequent ROV hot stab activation of the LMRP hydraulic connector, and has left the upper connector mandrel accessible to latch back on to. The BOP and wellhead is vertical.

Typical debris removal plans identify the provider that will conduct the debris removal activity, a recommended list of equipment for immediate callout, and where the equipment is retained. The debris removal plan should describe what tools the provider has available to sever the riser joints and associated riser piping to facilitate removal of debris from around the BOP stack and wellhead.

A.2.2 Removal of Drill Rig at Surface

If during an incident, the drill rig remains attached to the well or within the immediate incident zone, disconnecting the marine riser/LMRP attachment to the incident well, and safe removal of the damaged drill rig to outside the immediate incident location is a recommended practice.

If unable to disconnect the LMRP from the BOP, backup options could include release of the riser adapter connection above the LMRP flex joint via the riser connector or alternatively severing a riser joint above the LMRP. Severing the riser joint may require the cutting and removal of the integral choke and kills lines first to allow for an effective cut using pipe shears, diamond wire or other type of saw.

Prior to disconnecting the rig, riser, LMRP, BOP, etc. from the incident well, the incident owner shall have a written procedure. In this document, the incident owner should address contingency procedures and consider performing a risk assessment of the operation. The incident owner should have procedures covering the most likely disconnect scenarios on file prior to any well control event.

A.2.3 Wellhead Straightening

Should the conductor and high-pressure wellhead be deflected from vertical during the incident to an extent that restricts effective well capping operations, contingency plans for wellhead straightening should be developed.

Prior to straightening the incident well, the incident owner shall have a written procedure. In this document, the incident owner should address contingency procedures and shall perform and document a risk assessment of the proposed operation.

A.2.4 BOP Removal

Prior to disconnecting the BOP from the incident well to obtain a clean connecting surface for the subsea capping stack, the incident owner shall have a written procedure. In this document, the incident owner should address contingency procedures and consider performing a risk assessment of the operation.

One possible method of BOP removal is to use adapters connected to the BOP attachment points. As an alternative, the procedures should include the recovery of the failed BOP using rated lifting slings. Incident owners should be aware of any recovery load limitations of BOP frame lifting points.

A.2.5 Other Contingencies

A.2.5.1 General

It is prudent to plan for additional contingency measures. Prior to executing any contingency measures, the incident owner shall have a written procedure. In this document, the incident owner should address the need for additional contingency procedures and consider performing a risk assessment of the operation to ensure all hazards are identified and managed appropriately.

A.2.5.2 LMRP Cannot be Removed

In this case the entire BOP may be removed and the capping stack attached directly to the wellhead. Alternatively, a replacement BOP may be attached to the wellhead from another rig. A further option, if pressure ratings allow, is to attach the capping stack to the riser adapter. Additional planning and fabrication is required for a proper adapter between the subsea capping stack and the riser adapter.

A.2.5.3 Lower BOP is Damaged

In the event the lower BOP is no longer able to provide the required pressure capacity (e.g. due to internal damage flow related erosion), options to consider include removing the BOP to access the wellhead.

A.2.5.4 Attachment Point Profile is Damaged and Does Not Seal

If the ring gasket profile has minor damage, attempt to use an elastomeric backup type ring gasket. If the damage is too severe for this it would require additional tools to seal in another part of the wellhead.

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Annex B **(informative)**

Example Procedures

B.1 Example Procedure for Subsea Capping Stack Assembly and Testing

The following is an example outline procedure for capping stack assembly and testing that may be performed on the rig prior to rig deployment or on the quayside prior to mobilization onto a suitable vessel for deployment.

- 1) Place subsea capping stack modules in assembly area and remove packaging as required.
- 2) In separate secured area, begin pre-charging any required accumulators with inert gas based on the well specific water depth, capping stack specific operating volume required, and final capping stack specific closing pressure required.
- 3) Set test stump (if required) and connector module in assembly position.
- 4) Lift lower module onto connector module and make up flange per manufacturers procedure.
- 5) Build any required scaffolding around stacked-up modules to provide required access to stack-up next module.
- 6) Lift upper ram module onto lower ram module and make up flange per manufacturers procedure.
- 7) Build any required scaffolding around stacked-up modules to provide required access to stack-up next module.
- 8) Lift capping stack mandrel onto upper ram module and make up flange as per manufacturers procedure.
- 9) Install chokes on upper ram elbows and lock in place.
- 10) Connect the capping stack connector control hoses to lower ram module control panel.
- 11) Charge accumulators with required amount of BOP control fluid.
- 12) If applicable, charge required amount of accumulator volume with hydrate inhibitor.
- 13) Connect ROV flying leads from test pump module to lower ram module panel.
- 14) Perform function test of connector, rams, and valves per manufacturer's procedure.
- 15) Connect ROV flying leads from test pump module to upper ram module panel.
- 16) Perform function test of rams and valves per manufacturer's procedure.
- 17) Connect test pump to test stump and perform pressure test of lower and upper ram modules. Low-pressure and high-pressure test should be performed as per manufacture's procedure.

- 18) Pressure test the capping stack's valves and chokes.
- 19) Bleed off pressure, disconnect test pump, open rams and valves, and disconnect control fluid flying leads.
- 20) Flush all chemical injection and hydrate inhibitor ports.
- 21) Test accumulators and then recharge for deployment with operating fluids.
- 22) Function BOP side outlet valves.
- 23) Function chokes to open position.
- 24) Attach lifting gear to equipment and lift into moonpool of rig or onto suitable deployment skid located on the deck of deployment vessel.
- 25) Sea-fasten the capping stack in preparation for transit to offshore deployment location.

B.2 Example Procedure for Attaching Capping Stack

B.2.1 General

Prior to running the subsea capping stack, the incident owner shall have a well specific written procedure addressing attaching the capping stack to the well. In this document, the incident owner should address contingency procedures and consider performing a risk assessment of the operation. The incident owner should have procedures covering the most likely connection interfaces for their well on file prior to any well control event.

B.2.2 Example Capping Stack Attachment Procedure When a Hydraulic Connector Used

- 1) Run capping stack to depth on drill pipe (e.g. from drilling rig) or wire (e.g. from multiservice vessel using compensated crane or winch line or other heave compensation system).
- 2) Lower capping stack to a predetermined safe lateral distance from and safe working depth above the well to be capped and stop.
- 3) Confirm all components in the main bore of the capping stack are fully open and start flushing with chemical injection (hydrate inhibitors) if desired.
- 4) Move capping stack into the flow immediately above the well to be capped.
- 5) With ROV assistance as needed, land capping stack on the well to be capped.
- 6) Latch/lock connector to the flowing well via ROV panel. If possible, confirm latch with overpull on running string. Stop chemical injection flushing. Perform external seal pressure test, if applicable.
- 7) Engage secondary lock on the connector if applicable.
- 8) Consider releasing the deployment system from the capping stack; an important consideration if no emergency disconnect feature included.
- 9) Attach any power fluid supply and chemical injection supply flying leads from subsea deployed accumulator package (or ROV fluid/pump skid) to ROV panel(s) on capping stack.

B.3 Example Procedure for Operating the Capping Stack

B.3.1 General

Prior to running the subsea capping stack, the incident owner shall have a well specific written procedure addressing operating the capping stack. In this document, the incident owner should address contingency procedures and consider performing a risk assessment of the operation. The incident owner should have a well specific prediction of the expected pressure response during operation of the capping stack.

B.3.2 Example Capping Stack Operating Procedure to Secure the Well

- 1) Function open and/or confirm all diverter valves, and any associated diverter line chokes, in the full open position with ROV.
- 2) Close lower main bore element via ROV panel.
- 3) Monitor well pressure and compare with expected pressure response.
- 4) Progressively close chokes (or sequentially close diverter valves) on the diverter lines with ROV.
- 5) Monitor well pressure and compare with expected pressure response.
- 6) Move ROV to safe standby position; observe for leaks.
- 7) If any leaks observed from closed main bore element, close additional main bore element(s) if possible.
- 8) Monitor well pressure and compare with expected pressure response.
- 9) If available, run and latch a pressure cap on the capping stack main bore and, if possible, pressure caps on all the side outlet diverter lines.

B.4 Example Procedure for Recovering Capping Stack

B.4.1 General

Prior to recovering the subsea capping stack, the incident owner shall have a written procedure addressing unlatching the capping stack and depressurizing the system. In this document, the incident owner should address contingency procedures and consider performing a risk assessment of the operation. The incident owner should have recovery procedures covering the most likely connection interfaces for their well on file prior to any well control event.

B.4.2 Example Capping Stack Recovery Procedure

- 1) Confirm the hydrocarbon release has been fully controlled and contained.
- 2) Confirm the pressure inside the capping stack has been reduced to the ambient pressure and the hydrocarbons inside of the capping stack have been safely removed.
- 3) Conduct a visual inspection to ensure there are no hydrates or other equipment that may impede the removal of the capping stack. Remove any hydrates or other equipment impediment found before proceeding with the capping stack removal.
- 4) Ensure the capping stack is in a state such that a hydraulic lock is not caused during the retrieval process.

- 5) The capping stack should be removed by drill pipe (e.g. from drilling vessel) or wire (e.g. from multiservice type vessel using compensated crane or winch line or other heave compensation system).
- 6) Lower capping stack recovery system to a predetermined safe lateral distance from the top of the capping stack and prepare for attaching with ROV assistance.
- 7) Move over recover system and attach or land the deployment system onto the capping stack.
- 8) With ROV assistance, disengage the capping stack connector secondary lock if applicable.
- 9) Unlatch/unlock the connector of the capping stack via ROV panel. If possible, confirm unlatch with visual indicators.
- 10) Lift on the capping stack with the drill pipe or wire to a safe distance above the attachment point. Move to a predetermined safe lateral distance from the site.
- 11) Retrieve the capping stack to the surface using normal safety procedures for managing the risks associated with potential trapped pressure inside any part of the capping stack.
- 12) Land and sea-fasten the capping stack back on the drilling rig or multiservice type vessel before slacking off on the recovery system.

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