

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 Acronyms, Abbreviations, Symbols, and Units	3
4 System Requirements	4
4.1 General	4
4.2 Subsea Capping Stack Categories	4
4.3 Interface Descriptions	6
4.4 System Design and Functional Requirements	8
4.5 Manufacturing	22
5 Subsea Capping Stack Operations	25
5.1 General	25
5.2 Initial Actions	25
5.3 Equipment Notification and Callout	25
5.4 Well Condition Assessment	26
5.5 Deploying the Subsea Capping Stack	29
5.6 Operating Parameters	33
5.7 Operating Personnel	35
5.8 Logistics and Deployment Plans	35
6 Storage, Preservation, Maintenance, and Testing	37
6.1 General	37
6.2 Testing	37
6.3 Maintenance	43
6.4 Inspections	46
6.5 Preservation	48
6.6 Testing, Maintenance, Inspection, and Preservation Personnel	52
Annex A (informative) Subsea Well Capping Contingency Procedures	54
Annex B (informative) Example Procedures	57
Bibliography	61

Figures

1 Category 1 (Cap)	5
2 Category 2 (Cap and Flow)	6
3 Example of Three Likely Subsea Capping Stack Attachment Points	28

Contents

	Page
Tables	
1	Example of Pre-deployment Interface Testing Matrix 31
2	Example Routine Testing Schedule 38
3	Example Non-routine Testing Schedule 38
5	Example Periodic Maintenance Schedule 43
6	Subsea Capping Stack Field Performance Report Example 45

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. 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 does not address procedures and equipment downstream of the 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, recovery, and storage 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.

API Specification 6A, *Specification for Wellhead and Tree Equipment*

API Standard 6AV1, *Validation of Safety and Shutdown Valves for Sandy 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 Equipment*

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 Standard 17G, *Design and Manufacture of Subsea Well Intervention Equipment*

API Recommended Practice 17H, *Remotely Operated Tools and Interfaces on Subsea Production Systems*

API Standard 53, *Well Control Equipment Systems for Drilling Wells*

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

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 incident 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.

3.1.4

design validation

The process of proving a design by testing to demonstrate conformity of the product to design requirements.

NOTE Design validation can include one or more of the following (this is not an all-inclusive list):

- prototype tests;
- functional and/or operational tests of production products;
- tests specified by industry standards and/or regulatory requirements;
- field performance tests and reviews.

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.

3.1.5**design verification**

The process of examining the result of design and development output to determine conformity with specified requirements.

NOTE Design verification activities can include one or more of the following (this is not an all-inclusive list):

- confirming the accuracy of design results through the performance of alternative calculations;
- review of design output documents independent of activities of design and development;
- comparing new designs to similar proven designs.

3.1.6**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.

3.1.7**incident well**

A subsea well with uncontrolled flow to the environment.

3.1.8**management of change (MOC)**

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

3.1.9**pressure-containing**

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

3.1.10**pressure integrity**

The ability of an object to contain applied pressure.

3.1.11**subsea capping stack**

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

3.2 Acronyms, Abbreviations, Symbols, and Units

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

ΔP	differential pressure
BOD	basis of design
BOP	blowout preventer
CFD	computational fluid dynamics
FAT	factory acceptance test
FMECA	failure mode effects and criticality analysis
GOR	gas oil ratio

H ₂ S	hydrogen sulfide
HPU	hydraulic power unit
ICS	Incident Command System
Kpsi	1000-psi (pressure)
LMRP	lower marine riser package
LP	dye (liquid) penetrant
MOC	management of change
MPE	magnetic particle examination
MSDS	material safety data sheet
OEM	original equipment manufacturer
P&ID	piping 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 parameters for subsea capping stacks. The recommended parameters 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; and
- contain one or more outlets for diverting flow from and/or pumping kill fluid into the main vertical bore.

All subsea capping stacks should use field-proven or qualified components and assemblies.

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 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 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.

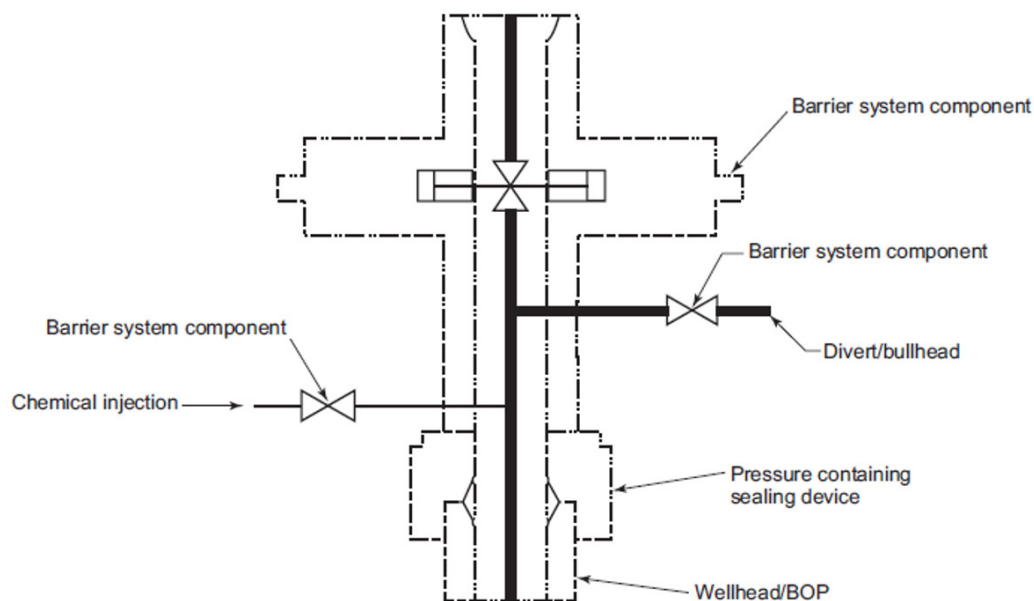


Figure 1—Category 1 (Cap)

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.

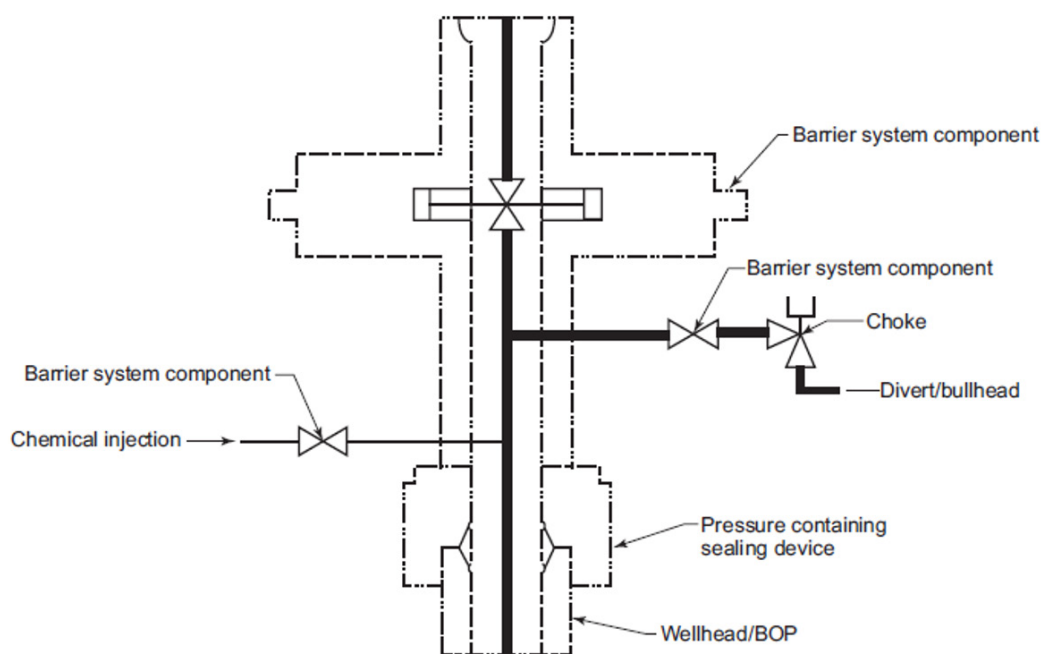


Figure 2—Category 2 (Cap and Flow)

4.3 Interface Descriptions

4.3.1 General

The purpose of a subsea capping stack is to shut-in uncontrolled flow from a wellbore (Category 1) or divert flow from the wellbore (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 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 17D 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.

NOTE 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.

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 17D for flange connections and API 17G for other connections. The functions of this interface may include accepting an additional subsea capping stack, installation handling 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. At 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

Subsea capping stacks and their components shall be designed to operate within the temperature classification conventions set forth by API 17D. 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. CFD analysis should include the following parameters, at a minimum:

- oil or condensate production (kBPD):
- oil flow rate (kBPD):
- oil density at BOP (kg/m^3):

- oil viscosity at BOP (cP):
- water production (kBPD):
- water flow rate (kBPD):
- water density at BOP (kg/m³):
- water viscosity at BOP (cP):
- gas production (MMSCFD)
- gas flow rate (MMSCFD)
- gas molecular weight (kg/kg-mol) at BOP:
- gas compressibility (Z) at BOP:
- gas ratio of specific heats at BOP:
- gas viscosity at BOP (cP):
- production temperature at BOP (°C):
- sea water temperature at BOP (°C):
- water depth (m):

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, at a minimum, 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. For depths greater than 10,000 ft, additional analysis may be necessary.

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; moonpool clearance for rig and vessel installations; the vessel's deckload capacity; and the potential need for load frame to spread the load.

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 (Category 2 only), and a minimum of 20 years of land-based preservation and maintenance service.

Life estimation and aging of components and materials within the subsea capping stack assembly shall be based on API 17D. Where available, the manufacturer may base the life estimation on known component failure and deterioration data (mean time between failure and shelf life). The manufacturer shall define additional applicable renewal of design verification and shelf life replacement schedules and demonstrate that 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, storage, maintenance, periodic renewal of design 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.

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 in accordance with API 17D for cathodic and corrosion protection and coatings. It is a recommended practice to design for accessibility to maintain the coating and cathodic protection systems/methods given the possible long-term land-based storage method.

Selection of stud, nut, and bolting materials and coating/plating should consider seawater-induced chloride stress corrosion cracking and corrosion fatigue. Bolting materials for service in a seawater environment shall conform to API 17G, 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 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.

Manufacturers shall provide documentation on storage and preservation environment requirements, periodic renewal of design verification based on bespoke reservoir properties, function and pressure testing for readiness, and the preparations required for deployment and subsea use.

4.4.3 Component Design

4.4.3.1 General

Subsea capping stack 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 depend 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 should 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.

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.

Component 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.

Devices used to shut off flow shall be designed to mitigate the effects of erosion and be designed and tested, at a minimum, to conform to API 6AV1 class II for sandy service per the component manufacturer normal service design criteria. 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 Erosion of Choking Devices

Subsea choking devices should be designed to withstand limited flow with debris and, at a minimum, 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 main bore closure device should be verified to close on the maximum flow defined by the subsea capping stack BOD. In the absence of a verified ram, a second main bore closure device shall be included. Any ram devices incorporated into the subsea capping stack design should be designed and operated in accordance with API 16A and API S53, respectively. A capping stack owner may generate its own operation procedures in lieu of those in API S53. Rams should also be designed and verified for flow with solids as per API 17G, considering the effects of erosion and the effects of solids accumulating in the cavities.

The subsea capping stack may include 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.

Ram designs should include position indicators and ram locks.

4.4.5.1.2 Valve as a Closure Device

A valve used as the main 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 main bore closure device shall be used. Valves should be either a gate or ball valve and be designed in conformance with API 17D or API 17G as applicable.

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, at a minimum, 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 Design Verification and Design Validation

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

Closure device design validation 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 design verification testing may be performed in lieu of full-scale flow testing.

Closure devices should conform to API 17G 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 design verification involves CFD analysis of the component design to determine reliability under the expected operational conditions. This design verification should include the following concurrent parameters:

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

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.) shall be available.

A secondary sealing barrier that locks onto the top mandrel of the capping stack shall be included as a component of the subsea capping stack system. The secondary sealing barrier shall provide a means for checking pressure between the subsea capping stack main vertical bore sealing element and the secondary barrier. It may also be necessary to include the capability to pump chemical below the secondary sealing barrier 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 17D or 16A as applicable for flange connections and API 17G for other connections.

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 the design requirements of API 17G.

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.

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. 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 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, studs, nuts, flanged end and outlet connections, and other connectors shall conform to their applicable specifications of API 6A, API 16A, API 17D, and API 17G.

4.4.5.3.4 Inlet and Outlet Connector Standardization

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.

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.

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

4.4.5.3.5 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 identify optimum placement of inlets enabling efficient mixing.

4.4.6 Controls

4.4.6.1 General

Subsea capping stack control systems shall meet the requirements of API 16D and API 17G5.

The subsea capping stack control system shall conform to 4.4.6.3.

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 all main bore and diversion outlet closure devices to the closed position 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

Closure times for main bore and side/diverter outlets should be stated in the capping stack BOD. 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 hot stab receptacles that meet the requirements of API 17H. Functions that meet the closure times of this document, such as rams used as a vertical main bore closure device, shall be fitted high-flow hot stabs (API 17H Type 3 or Type 4), which include external locking devices. These hot stabs shall be clearly marked and labeled: a) on the equipment, and b) on the subsea capping stack drawings and documentation.

Subsea capping stack interface components and gauges shall 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 should 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 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.