Subsea Capping Stack Technology Requirements

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Jorge Alba, PhD, PE
jorge.alba@woodgroupkenny.com
Tel: +1 281 646 4160

Wood Group Kenny
15115 Park Row
3rd Floor
Houston, TX 77084

Tel +1 281 675 1000
http://www.woodgroupkenny.com

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Limitations of the Report

The scope of this report is limited to the matters explicitly covered and is prepared for the sole benefit of the Bureau of Safety and Environmental Enforcement (BSEE). In preparing the report, Wood Group Kenny (WGK) relied on information provided by BSEE and third parties. WGK made no independent investigation as to the accuracy or completeness of such information and assumed that such information was accurate and complete.

All recommendations, findings, and conclusions stated in this report are based on facts and circumstances as they existed at the time this report was prepared. A change in any fact or circumstance on which this report is based may adversely affect the recommendations, findings, and conclusions expressed in this report.

Executive Summary

Since 2010, the industry has made great strides in increasing the capabilities for subsea well control response based on learnings from the Macondo incident. This study provides a detailed analysis of the subsea capping stack availability, storage locations, and technical capabilities. This study also reviews the regulations and standards and a draft Code of Federal Regulations (CFRs) and a Potential Incident of Noncompliance (PINC) list for subsea capping stacks has been developed.

The subsea capping stack is part of the Source Control and Containment Equipment (SCCE), along with the cap and flow system, the containment dome, and other subsea and surface devices, equipment, and vessels. The collective purpose of SCCE is to control a spill source and stop the flow of fluids into the environment. This study, which is specific to subsea capping stacks, does not consider other SCCE.

Literature Review and Industry Surveys

Wood Group Kenny (WGK) has conducted a detailed literature review to evaluate available U.S. regulations for source control and containment. It was determined that current U.S. regulations include no information related to SCCE. The Bureau of Safety and Environmental Enforcement (BSEE) issued Notice to Lessees and Operators (NTL) 2010-N10, which required Operators to demonstrate that they have access to capping and containment equipment to receive approval for the Application for Permit to Drill (APD). In April 2015, the BSEE published a Proposed Rule for well control that would consolidate the current regulations and NTLs. As part of the Proposed Rule, the BSEE provided a separate section for source control and containment.

In February 2015, the Department of the Interior (DOI), acting through the BSEE and the Bureau of Ocean Energy Management (BOEM), proposed regulations on requirements for exploratory drilling in the Arctic Outer Continental Shelf (OCS). This proposed Arctic regulation requires access to SCCE with a subsea capping stack positioned to arrive at a well within 24 hours after a loss of well control, and a cap and flow system and a containment dome positioned to arrive at the well within 7 days after a loss of well control. Currently, there are no active U.S. regulations or inspection criteria guidelines for subsea capping stacks.

American Petroleum Institute Recommended Practice (API RP) 17W provides guidelines for the design, manufacture, use, preservation, transportation, and maintenance procedures of subsea capping stacks. The development and delivery of subsea capping stacks began immediately following the Macondo incident in 2010, prior to the issuance of API RP 17W. The design of these systems was based on the existing subsea equipment (for example, Blowout Preventer [BOP] rams, valves, and chokes), for which industry standards were already established. The strategy for the design of subsea capping stacks was employed to allow for rapid delivery to industry, based on conventional components, field-proven track records, accepted reliability, established technical knowledge base, and availability of spare parts. In addition, an objective of this strategy was to avoid the high costs and long lead times generally associated with the development of new safety equipment technology by shortening the process typically associated with its conception, design, fabrication, testing, and certification.

Subsea Capping Stack Availability

The consortiums and organizations that own subsea capping stacks are listed in the following table.

Name	Type	No. of Subsea Capping Stacks	Staging Location	Region Served
MWCC	Consortium	3	Ingleside, TX	U.S. Gulf of Mexico
HWCG	Consortium	2	One in Houston, TX and another in Ingleside, TX	U.S. Gulf of Mexico
OSPRAG	Consortium	1	Aberdeen, Scotland	U.K. Continental Shelf
OSRL	Consortium	4	One at each location: Brazil, Norway, Singapore, and South Africa	Global (except U.S. waters)
WellCONTAINED	Organization	2	One in Aberdeen, Scotland and another in Singapore	Global (inclusive of U.S. waters)
Shell	Operator	3	One in Alaska; others in Aberdeen, Scotland, and Singapore	Global (Shell operations only)
BP	Operator	2	One in Houston and another in Angola	Houston stack (Global BP operations) Angola stack (BP operations only in Angolan waters)

For the U.S. Gulf of Mexico (GOM), it is mandatory for Operators conducting subsea drilling operations to demonstrate access to a subsea capping stack and the necessary expertise and assets to mobilize and install the stack offshore. Five subsea capping stacks to facilitate compliance with this requirement are staged within the Gulf Coast region. Two consortiums and one organization support the U.S. GOM. The Marine Well Containment Company (MWCC) is a consortium that provides access to three subsea capping stacks, and HWCG LLC is a consortium that provides access to two subsea capping stacks. In addition, WellCONTAINED organization maintains two subsea capping stacks outside of the U.S. These stacks can be mobilized to U.S. GOM if needed. Currently, WellCONTAINED does not support Operators in obtaining permits to drill in the U.S. GOM region.

For the U.K. Continental Shelf (UKCS), three subsea capping stacks are staged within the region. The Oil Spill Prevention and Response Advisory Group (OSPRAG) is a consortium that has one subsea capping stack staged in Aberdeen, U.K. The WellCONTAINED organization has one subsea capping stack staged in the U.K., which is available for global use. The Oil Spill Response Limited (OSRL) consortium has one subsea capping stack staged in Norway that is available for global use.

Outside of the U.S. and U.K. regions, excluding Operator-owned stacks, the industry has access to six subsea capping stack systems that are made available through the OSRL consortium and the WellCONTAINED organization. The OSRL consortium has a total of four subsea capping stacks that are available for use outside of U.S. waters; they are staged in Norway, Brazil, Singapore and South Africa. The WellCONTAINED organization has two subsea capping stacks available for use globally; they are staged in the U.K. and Singapore.

In summary, the U.S. and U.K. are the only regions with dedicated consortiums (e.g., MWCC, HWCG, and OSRPAG) to support subsea capping stack response. However, there is subsea capping stack access for all regions of the world through the OSRL consortium and the WellCONTAINED organization. The caveat to this statement is that most of the countries do not have regional access to a subsea capping stack, and they are dependent on the consortium or the organization-owned capping solutions staged at varying strategic locations around the world. It can be surmised that these regions and countries will likely have longer response times because of the length of time associated with marine transport of the subsea capping stack from their storage locations to the incident sites.

Recommended CFR and PINC List

WGK has worked with the Well Containment Consortiums (MWCC, HWCG LLC, and OSRL) and a manufacturing company (Trendsetter Engineering) to draft regulations for subsea capping stacks based on global learnings and experience with subsea capping stacks. WGK recommends that the drafted Code of Federal Regulations (CFR) be incorporated as part of 30 CFR 250 Subpart D.

WGK also drafted the PINC List for subsea capping stacks in accordance with the format included in the National PINC Guideline List. WGK participated in a workshop with the Well Containment Consortiums to review the draft PINC List and to get their feedback. WGK recommends that the PINC List be appended to the current Drilling PINCs. BSEE personnel can use this PINC List for inspection in the field and at onshore support bases.

The subsea capping stack CFR and the PINC List are only recommendations to BSEE: BSEE may modify and use them in the future.

Recommendations:

- Evaluate subsea capping stack components that can accommodate weight savings. This could involve using gate valves instead of BOP rams for smaller bore sizes. The gate valves can provide the same pressure rating as BOP rams. The benefits associated with the use of gate valves include improved sealing reliability (metal-metal sealing surface), reduction in weight, and simplified operation, thereby avoiding the need for Subsea Accumulator Module (SAM) units.
- Because of the geographic distances between subsea capping stack storage locations and potential incident sites, it is recommended that a specific subsea capping stack should be identified prior to the commencement of operations within each deep water drilling region and the associated mobilization planning that is conducted to determine the estimated response time. This process would allow for the assessment of an estimated response time to ensure that it is acceptable as well as to identify areas for efficiency improvement related to deployment and installation
- Develop subsea capping stacks for High Pressure High Temperature (HPHT) conditions. The consortium owners should consider procuring new HPHT subsea capping stacks or improving the capabilities of the existing ones, depending on the members' planned wells to which the consortium may need to respond. Shell has contracted Trendsetter to deliver a 400°F subsea capping stack in 2016, and MWCC has contracted Trendsetter to deliver a 20,000 psi subsea capping stack by 2017.
- Review other parts of SCCE (such as the containment system[1], debris removal, and dispersant equipment). Currently, there are no minimum requirements for the containment system and no consistency on what defines a containment system. There are different technologies and levels of containment system (interim versus long-term), depending on the capabilities. It must be noted that the absence of 'minimum requirements' or a definition of a containment system has allowed development (in the U.S. GOM at least) of two different, robust solutions. In addition, the interfaces between subsea capping stacks and containment systems have not been standardized; this could lead to delays in deployment and recovery operations should an incident occur.
- Although BSEE currently uses terminology such as 'Cap,' 'Cap and Flow,' and 'Source Control and Containment Equipment,' it is highly recommended that this terminology be assessed and reviewed against terminology which is being standardized internationally.

[1] A containment system includes any system or component downstream of the subsea capping stack that directs flow.

Some examples of major discrepancies include the U.S. term ‘Cap and Contain’ (which means installation and shut-in with a subsea capping stack), while the term ‘Capping’ means the same thing internationally. In the U.S., the term ‘Cap and Flow’ implies that a capping stack has been installed, but the well is being flowed to a surface vessel; internationally, the term ‘Containment’ has the same meaning.

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1.0 Introduction

1.1 General

Wood Group Kenny (WGK) has written this report in compliance with the Bureau of Safety and Environmental Enforcement (BSEE) Contract number E14PC00030 to assess the state-of-the-art subsea capping stack technologies with the potential to increase safety during Outer Continental Shelf (OCS) drilling, well completion, well workover, and production operations.

The work associated with this contract is a result of the proposal submitted in response to Broad Agency Announcement E14PS00052 for proposed research on the Safety of Oil and Gas Operations in the U.S. OCS.

1.2 Background

During a subsea drilling operation, the downhole pressures are controlled by the drilling mud balancing the hydrostatic pressure. If the balance of the drilling mud pressure is incorrect and a permeable formation is exposed, then formation fluids begin to flow into the wellbore and up the annulus. This is commonly called a 'kick.'

The primary method for detecting a kick is the relative change in the circulation rate back up to the surface and into the mud pits. The drilling crew keeps track of the mud pit levels and closely monitors the rate of mud returns versus the rate that is pumped down the drill pipe. Early warning signs of a kick include:

- Sudden change in drilling rate.
- Change in surface fluid rate.
- Change in pump pressure.
- Reduction in drill pipe weight.
- Mud returns mixed with gas, oil, or water.
- Connection gases, high background gas units, and high bottoms up gas units in the mud logging unit.

An undetected and unmanaged kick can quickly transform into a blowout if the pressure control device fails and the formation fluids reach the surface. The subsea Blowout Preventer (BOP) is a pressure control device that is placed on the wellhead prevents a blowout from occurring. The subsea BOP consists of large, specialized valves and rams called the annular preventers, pipe rams, casing shear rams, and blind shear rams that are used to shear the drill pipe and seal the well. The BOP monitors the formation fluid flow and pressures and is capable of pumping and receiving fluids through the choke and kill lines.

During a well control scenario, the annular preventer is typically activated first to seal the annulus and prevent fluids from reaching the surface. If the well is not under control after activating the annular preventers, the pipe rams are activated. The pipe rams are located between the annular preventer and the shear rams. If the annular preventer and pipe rams fail to control the well, blind shear rams are used to shear the drill pipe and seal the well. Casing shear rams are used to shear the casing, but they cannot seal the well.

The activation of the subsea BOP is controlled from the topsides using the primary BOP control system. If the primary control system fails for any reason, an alternate BOP control system such as the Acoustic Control System or Remotely Operated Vehicle (ROV) intervention is used. Emergency Disconnect Sequence (EDS) systems and Emergency Shut Down systems (for example, Deadman system, Automatic Mode Function [AMF], Autoshear system) provide automatic disconnection of the riser if there is loss of power or if failure of the hydraulic or communication systems occurs.

If the BOP fails to prevent the blowout and the well is in flowing condition, a subsea capping stack closest to the incident well location is mobilized to the incident site and is deployed on the flowing well. The hydrocarbons flow through the subsea capping stack main bore and the diverter outlets. The main bore is closed, followed by the closure of each diverter outlet, to stop the flow. During the diverter outlet closing stage, the wellbore pressure is monitored, and if it goes higher than the allowable pressure, the well cannot be completely sealed and a containment system is required to capture the fluids and transfer them to the surface.

The subsea capping stack and containment system can serve as a temporarily solution to stop the flow until a permanent means such as drilling a relief well has been found.

1.3 Report Objectives

The objectives of this report are to:

- List the geographical locations where subsea drilling is ongoing or planned
- List existing subsea capping stacks that are available for global deployment
- Develop a drilling activity map versus the storage locations of existing subsea capping stacks
- Perform a detailed review of literature related to subsea capping stacks
- Conduct an industry survey and obtain feedback from the industry
- Assess the technical capabilities of each subsea capping stack
- Develop functional specifications for each subsea capping stack
- Compile actual deployments and learnings from subsea capping stacks
- Provide guidelines for integrating capping capabilities with 30 CFR 250

- Develop inspection criteria guidelines for subsea capping stacks
- Generate a Potential Incident of Noncompliance (PINC) List
- Provide general industry practices for using subsea capping stacks

1.4 Abbreviations

Below is a list of abbreviations that are used throughout this report.

ACI	American Concrete Institute
AISC	American Institute of Steel Construction, Inc.
AMF	Automatic Mode Function
AMOSC	Australian Marine Oil Spill Centre
ANSI	American National Standards Institute
APD	Application for Permit to Drill
API	American Petroleum Institute
API RP	American Petroleum Institute Recommended Practice
APM	Application for Permit to Modify
BOD	Basis of Design
BOEM	Bureau of Ocean Energy Management
BOP	Blowout Preventer
bpd	Barrels per day
BSEE	Bureau of Safety and Environmental Enforcement
CFD	Computational Fluid Dynamics
CFR	(U.S.) Code of Federal Regulations
CNSOPB	Canada-Nova Scotia Offshore Petroleum Board
CTTH	Coil Tubing Termination Head
DNV	Det Norske Veritas (now known as DNV GL)
DOCD	Development Operations Coordination Document
DOE	Department of Energy
DOI	Department of the Interior
EDS	Emergency Disconnect Sequence
EH	Electro-Hydraulic

EMOB	Emergency Mobilization Authorization Form
EP	Exploration Plan
EPA	Environmental Protection Agency
FLOT	Flying Lead Orientation Tool
FMECA	Failure Mode Effects and Criticality Analysis
FSC	Fail-Safe Close (valves)
GIRG	Global Industry Response Group
GOM	Gulf of Mexico
HCLS	Heave Compensated Landing System
HESG	Helix Energy Solutions Group
HFL	Hydraulic Flying Lead
HFRS	Helix Fast Response System
HPHT	High Pressure High Temperature
HPU	Hydraulic Power Unit
INC	Incident of Noncompliance
IOGP	International Association of Oil & Gas Producers
IOM	Installation, Operation, and Maintenance
IOP	Integrated Operations Plan
IRF	International Regulators Forum
ISO	International Organization for Standardization
JIP	Joint Industry Partnership
LMRP	Lower Marine Riser Package
LVOT	Linear Valve Override Tool
MAWHP	Maximum Anticipated Wellhead Pressure
MCA	Maritime & Coastguard Agency
MCV	Modular Capture Vessel
MNZ	Maritime New Zealand
MODU	Mobile Offshore Drilling Unit
MUX	Multiplex

MWCC	Marine Well Containment Company
NACE	National Association of Corrosion Engineers
NOPSEMA	National Offshore Petroleum Safety and Environmental Management Authority
NORECO	Norwegian Energy Company ASA
NORSOK	Norsk Sokkels Konkuranseposisjon
NTL	Notices to Lessees and Operators
OCS	Outer Continental Shelf
OEM	Original Equipment Manufacturer
OSPRAG	Oil Spill Prevention and Response Advisory Group
OSRL	Oil Spill Response Limited
OSRP	Oil Spill Response Plan
PDVSA	Petróleos de Venezuela S.A.
PETRONAS	Petroliam Nasional Berhad
PINC	Potential Incident of Noncompliance
PLET	Pipeline End Termination
PSA	Petroleum Safety Authority
psi	Pounds per square inch
PTTEP	PTT Exploration and Production Plc.
PVT	Pressure Volume Temperature
RCD	Regional Containment Demonstration
ROV	Remotely Operated Vehicle
RP	Responsible Party
RPSEA	Research Partnership to Secure Energy for America
RWP	Rated Working Pressure
SAE AS	SAE International Aerospace Standard
SAM	Subsea Accumulator Module
SCA	Subsea Containment Assembly
SCCE	Source Control and Containment Equipment
SEMS	Safety and Environmental Management System

SFRT	Subsea First Response Toolkit
SIMOPS	Simultaneous Operations
SIRT	Subsea Incident Response Toolkit
SOSREP	Secretary of State's Representative for Maritime Salvage and Intervention
SSV	Surface Safety Valve
SURF	Subsea Umbilicals, Risers, and Flowlines
SWIS	Subsea Well Intervention Service
SWRP	Subsea Well Response Project
TAC	Technical Advisory Committee
TLP	Tension-Leg Platform
TRL	Technology Readiness Level
U.S.	United States
UC	Unified Command
UKCS	United Kingdom Continental Shelf
USV	Underwater Safety Valve
UV	Ultraviolet (radiation)
VOCs	Volatile Organic Compounds
WCCP	Well Control Contingency Plan
WCST+	Well Containment Screening Tool Plus
WESI	Waterford Energy Services Inc.
WGK	Wood Group Kenny
WOM	Worldwide Oilfield Machine, Inc.
WSD	Work Stress Design
WWC	Wild Well Control

2.0 Source Control and Containment (or Well Containment)

2.1 Introduction

This section provides an overview of the source control and containment along with the containment procedure and the equipment required at each stage of the containment process. *Source Control and Containment Equipment (SCCE),* as defined by BSEE in the proposed regulation, includes a subsea capping stack, cap and flow system[2], containment dome[3], and/or other subsea and surface devices, equipment, and vessels whose collective purpose is to control a spill source and stop the flow of fluids into the environment or to contain fluids escaping into the environment.

The equipment mounted on the barge, vessel, or facility to separate, treat, store, and/or dispose of fluids conveyed to the surface by the cap and flow system are referred to as 'surface devices.' ROVs, anchors, buoyancy equipment, connectors, cameras, controls, and other subsea equipment necessary for deployment, operation, and retrieval of SCCE are referred to as 'subsea devices.' The BOP is not part of SCCE.

2.2 Post-Blowout Remediation

If the subsea BOP fails to prevent the flow of hydrocarbons from the well, additional equipment for installation and activation to contain the oil flow must be transported to the incident site.

When the Macondo well leaked in 2010, oil containment methods included the containment dome (May 7), top kill and junk shot (May 26), and a cap (referred to as 'top hat') for funnelling oil and gas to a surface ship (June 3). While the containment dome and top kill are not successful, the 'top hat' was successfully used to collect approximately 17,000 bpd, which was processed and off-loaded from the *Discoverer Enterprise* drill ship. The estimated total collected through the 'top hat' is 550,000 barrels of oil.

Meanwhile, the subsea capping stack was designed and assembled specifically for the leaking Macondo well. The subsea capping stack's design consisted of three rams, a

[2] *Cap and flow system* means an integrated suite of equipment and vessels, including the subsea capping stack and associated flowlines, that, when installed or positioned, is used to control the flow of fluids escaping from the well by conveying the fluids to the surface to a vessel or facility equipped to process the flow of oil, gas, and water.

[3] *Containment dome* means a non-pressurized container that can be used to collect fluids escaping from the well or equipment below the sea surface or from seeps by suspending the device over the discharge or seep location. The containment dome includes all of the equipment necessary to capture and convey fluids to the surface.

wellhead connector, a mandrel on top, two double-block drilling valves on the choke and kill outlets of the middle ram, and associated ROV panels. The subsea capping stack was installed onto and adapter fitted to the Lower Marine Riser Package (LMRP) flex joint on July 12.

Shortly thereafter, the subsea capping stack was shut in successfully, 'capping' the well, and providing the opportunity for engineers to perform a static kill (August 3), completing the relief well during August, and completing the abandonment. The U.S. federal government declared the well dead on September 21, 2010 [1].

Since the Macondo incident, regulations for drilling in the U.S. OCS have become more stringent for critical well control equipment.

Some of the requirements that are currently active or proposed following the Macondo incident are:

- American Petroleum Institute Recommended Practice (API RP) 53 Recommended Practice for Well Control Operations has been updated to a Standard.
- All wells that are to be drilled must have access to a subsea capping stack that can respond to a blowout or other loss of well control in a timely manner.
- Operators must provide details of the accessible subsea capping stack in the Application for Permit to Drill (APD).
- Regulations to ensure safe and responsible exploratory drilling on the Arctic OCS have been proposed.
- New BOP and well control regulations are proposed to include source control and containment requirements.
- A registered Professional Engineer must be involved in the casing and cementing design process.
- Specifications for independent third party certification have been increased.

2.3 Subsea Capping Stacks

A 'subsea capping stack' is a device that is placed over the flowing well to stop or redirect the flow of hydrocarbons. A subsea capping stack is designed to restore well control and mitigate environmental impacts, but it is considered a temporary fix until the well can be killed by hydraulic means. Because of the large size and weight of the subsea capping stack, transportation from the storage location to the incident well can be challenging.

Although it is not required onsite during a drilling operation, a subsea capping stack is required to be readily available at an onshore location. Specific to drilling in the U.S. Arctic region, the subsea capping stack is placed on a vessel close to the drill site because it may take more time to get it from an onshore location during a well control scenario. The subsea capping stack is deployed only after the BOP fails and a blowout occurs. Figure 2.1 shows a 15,000-psi subsea capping stack.

Figure 2.1: 15,000-psi Subsea Capping Stack [2]

A subsea capping stack differs from a subsea BOP. The subsea BOP is intended to prevent a blowout from occurring, whereas a subsea capping stack is intended to stop or redirect the flow after the blowout has occurred.

The major functions of a subsea capping stack are:

- Shut in or isolate a well
- Act as a diverter for flow back (containment operations)
- Facilitate the injection of kill fluids into the wellbore
- Facilitate chemical injection
- Facilitate the monitoring of critical wellbore parameters

2.3.1 Subsea Capping Stack Categories

The basic types of subsea capping stacks, as defined by API RP 17W [3], are:

- Cap only
- Cap and flow

As the name indicates, the 'cap only' subsea capping stack shuts off the flow of fluids. Cap only subsea capping stacks connect to a flowing well and temporarily divert the wellbore fluids to facilitate closure of the main bore, followed by closure of the diverter outlets. These subsea capping stacks also provide the interface to pumping equipment for injecting kill fluid into the wellbore. Cap only subsea capping stacks are commonly used when the wellbore maintains pressure integrity during shut-in of the subsea well. Figure 2.2 depicts a general configuration of a cap only subsea capping stack.

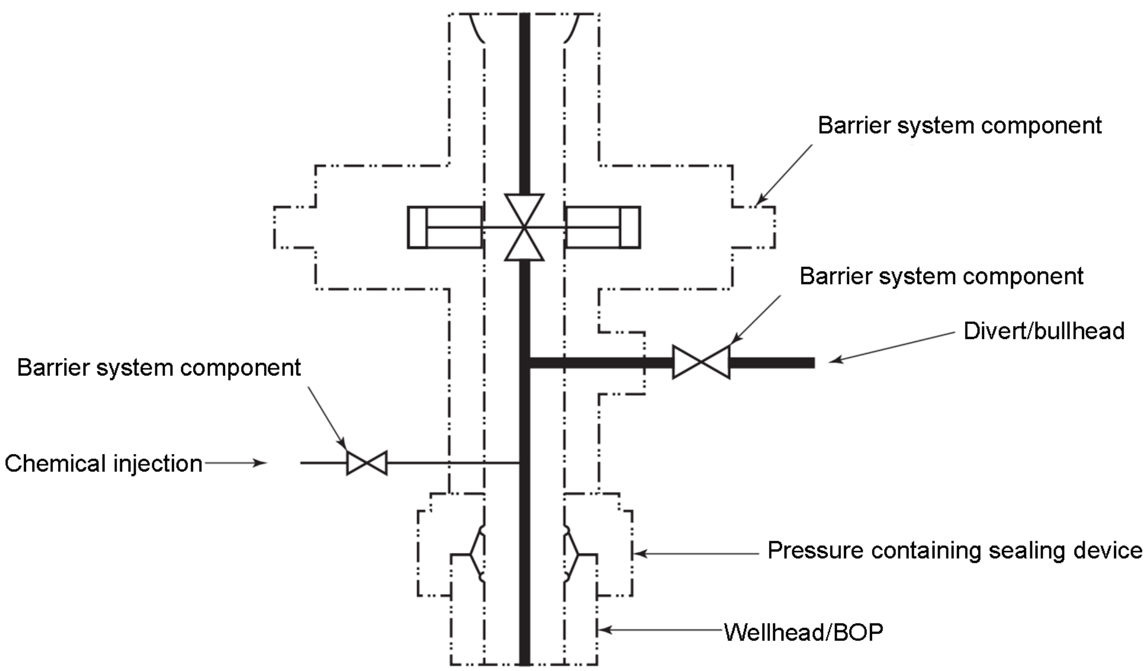


Figure 2.2: Cap Only [3]

The 'cap and flow' subsea capping stack shuts off the well and redirects the flow of fluids through flexible pipes and risers to one of the containment system's MCVs for processing and offloading. Figure 2.3 shows a general configuration of a cap and flow subsea capping stack.

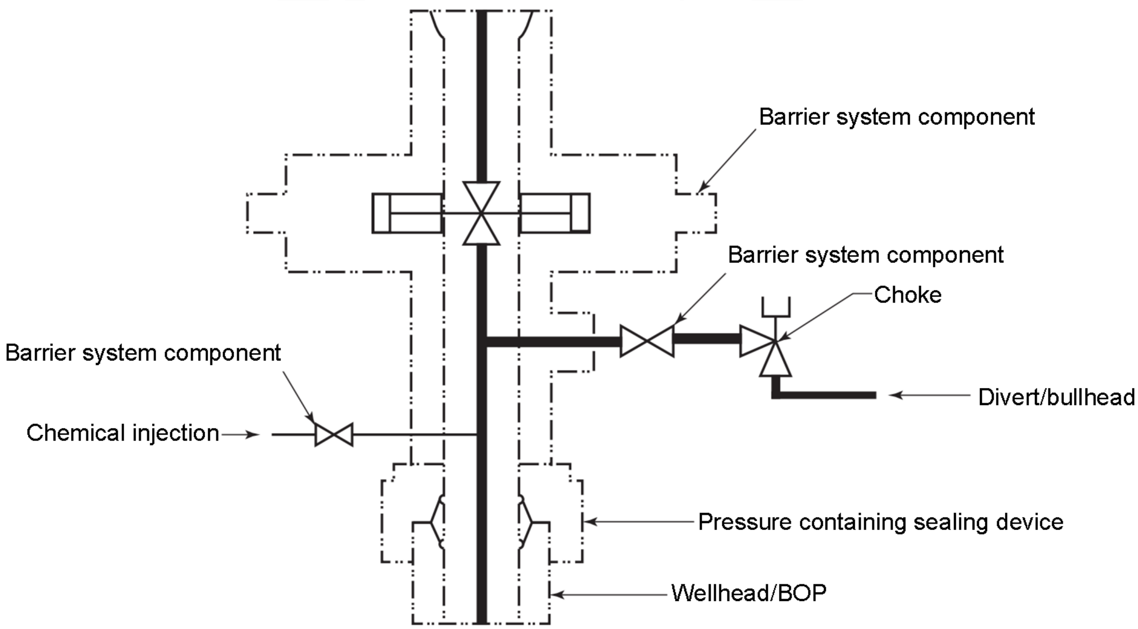


Figure 2.3: Cap and Flow [3]

The cap and flow subsea capping stack has the following functions:

- Connects to a wellbore
- Shuts in the well
- Diverts wellbore fluids to facilitate closure of the main bore
- Interfaces to pumping equipment for injecting kill fluid into a wellbore
- Controls the rate of flow through diversion outlets with a choking device

2.3.2 Major Components of a Subsea Capping Stack

A subsea capping stack is composed of a variety of tools and components that perform different functions. (Refer to Figure 2.4.)

The major components of a typical subsea capping stack include:

- BOP rams.
- Gate valves.
- Wellhead connector (or lower connector).
- Diverter spool assembly.
- Flowline connectors.
- Dual valves.
- Vector connectors.

- Choke.
- Chemical injection panel.
- Wellhead panel.
- Secondary cap (some available subsea capping stacks do not have these).
- Top mandrel.
- Spacer spools.

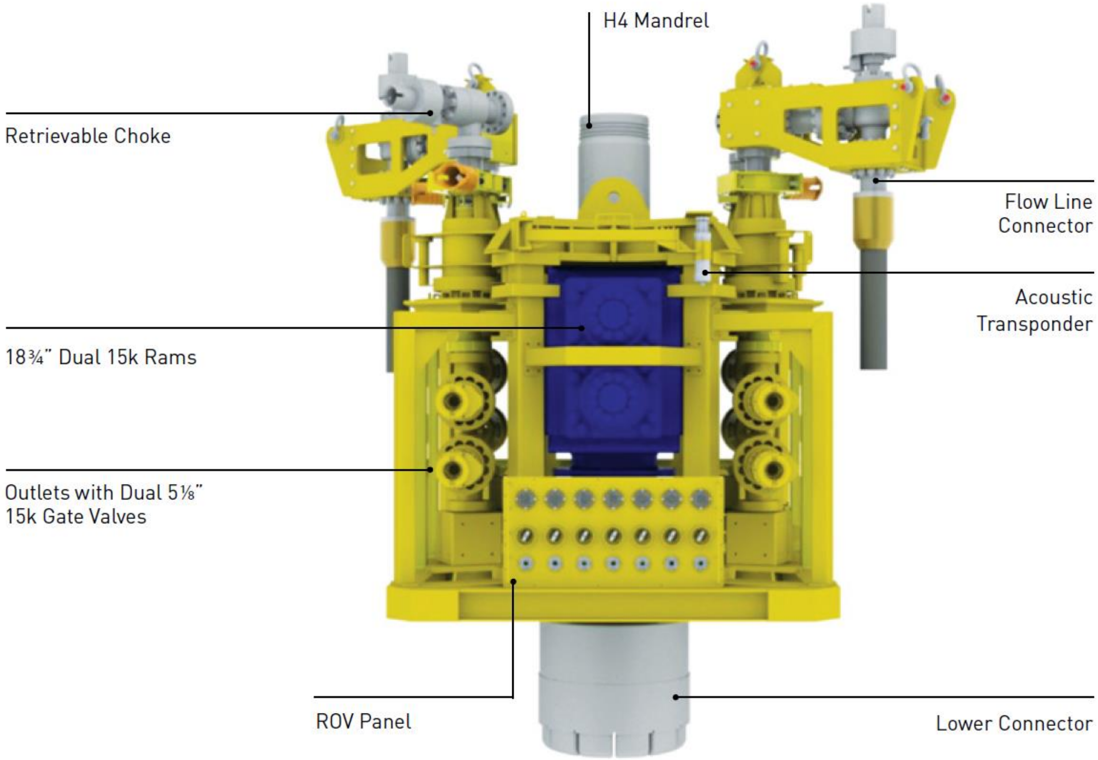


Figure 2.4: Typical Subsea Capping Stack with Component Description [4]

Rams: Rams are used in the subsea capping stack to close and seal the main bore. When the main bore closes, the flow runs toward the diverter outlets. Debris removal is performed before the subsea capping stack latches onto the wellhead/BOP. Typically, the blind rams control the flow and seal the well. Figure 2.5 shows a typical BOP ram.

Figure 2.5: BOP Ram [5]

Gate Valves: In some subsea capping stacks, gate valves act as main bore closure devices instead of rams. These valves must have ROV override capabilities and conform to API RP 17H [6]. In addition, the valves used must be qualified for flow with solids and tested to conform to API Specification 6AV1 Class II for sandy service. Figure 2.6 shows a typical subsea capping stack with gate valves.

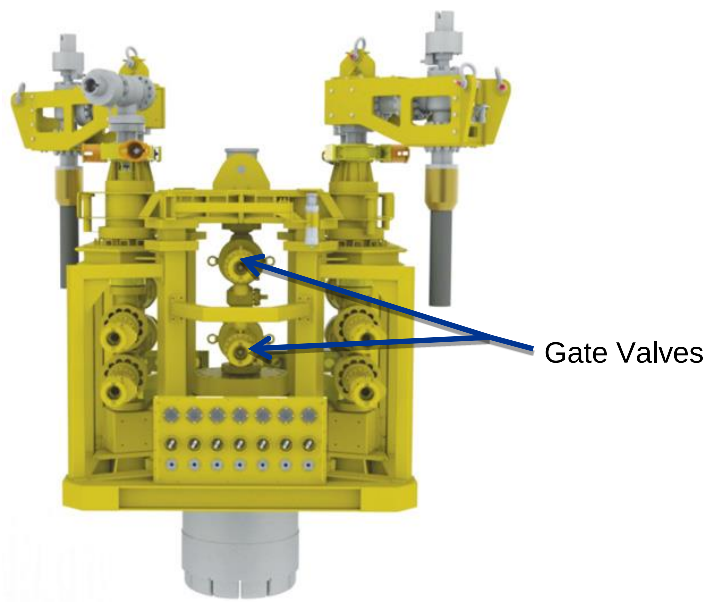


Figure 2.6: Subsea Capping Stack with Gate Valves [4]

Wellhead Connector: The wellhead connector, which is shown in Figure 2.7, provides a profile to latch the subsea capping stack to the wellhead and access to the wellbore in a secure, pressure-controlled environment. The connector is hydraulically actuated to interface with the incident well and is operable by ROV intervention.

Figure 2.7: Wellhead Connector

Diverter Spool Assembly: The diverter spool assembly is located below the BOP and above the wellhead connector. It diverts the fluid from the vertical main bore to the side outlets. Figure 2.8 shows the diverter spool assembly that is placed in a container with two spools on each side.

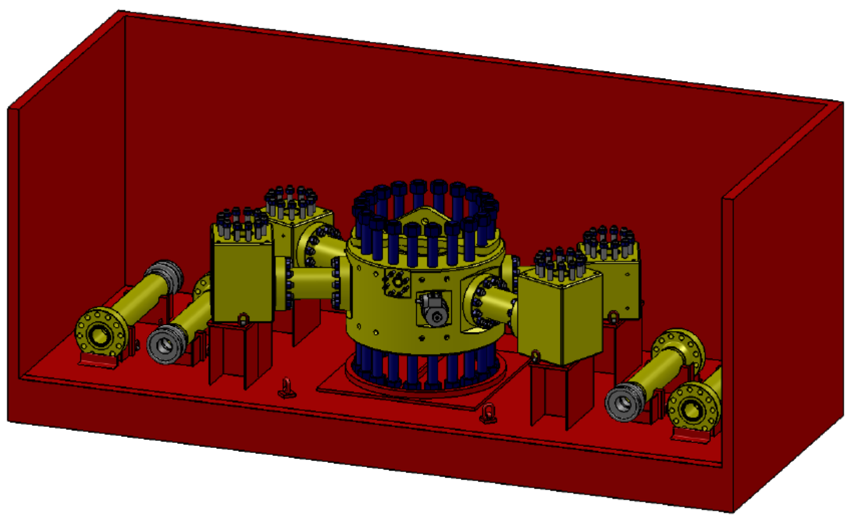


Figure 2.8: Diverter Spool Assembly with Four Inner Spools [4]

Diverter Isolation Valves: The diverter isolation valves, which are located on the diverter spool assembly, control the flow through the diverter valves. Figure 2.9 shows the dual valves used on the Oil Spill Response Limited (OSRL) subsea capping stacks.

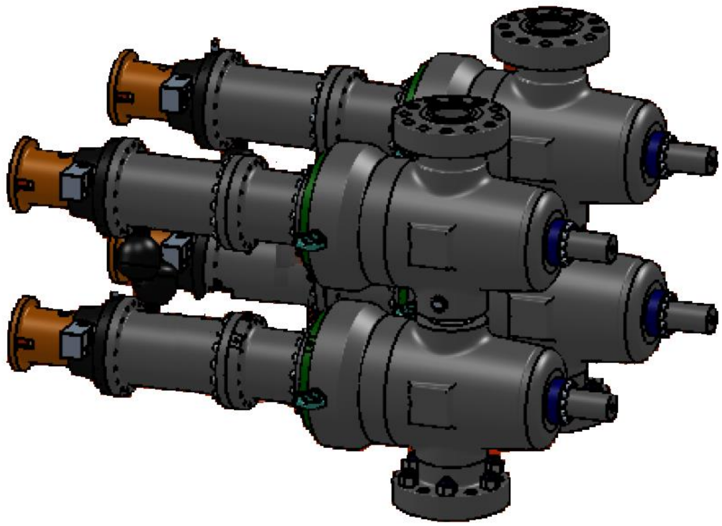


Figure 2.9: Dual Valves [4]

Flowline Connectors: The flowline connectors are required for 'cap and flow' type subsea capping stacks to connect to the flexible riser and for fluid transfer to the MCV. Typically, the connectors have an API Standard flange interface on the flow spool outlets and are downstream of any chokes. Figure 2.10 shows the flowline connector on the OSRL subsea capping stacks, respectively.

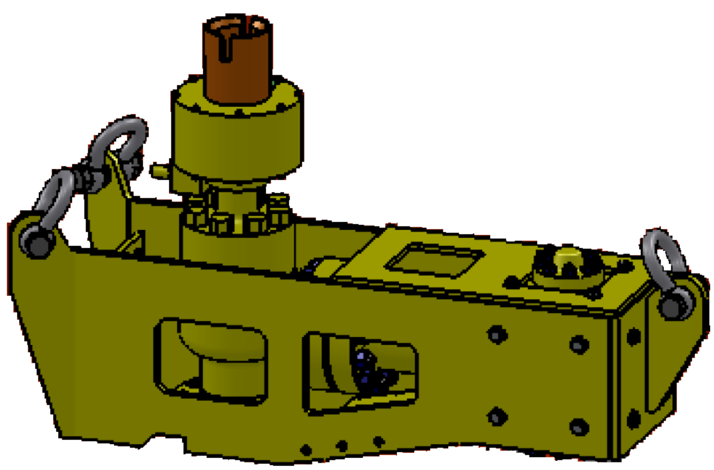


Figure 2.10: Flowline Connector [4]

Vector Connector with a Choke Valve: The ROV-operated vector connectors are affixed to the diverter assembly. In the 'cap only' containment scenario, the choke valves on the side outlets are closed, causing complete shut-off of the incident well. Figure 2.11 shows the vector connector with a choke valve.

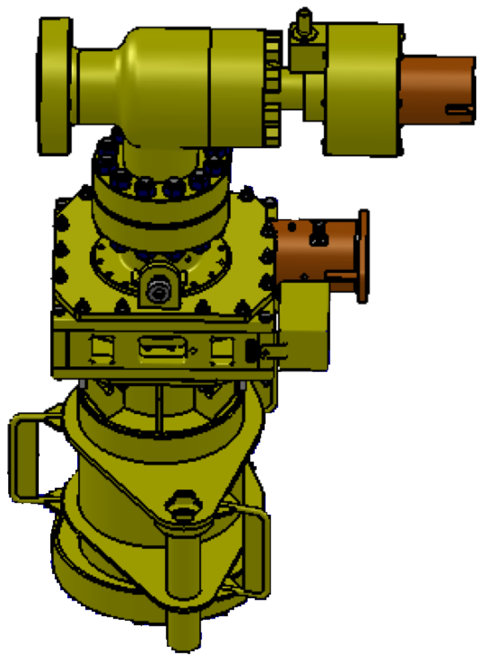


Figure 2.11: Vector Connector with a Choke Valve [4]

Secondary Cap: The secondary cap is provided to the top mandrel of the subsea capping stack as an additional safety barrier. This is done after the main bore and diverter outlets are successfully sealed. Figure 2.12 shows the secondary containment cap.

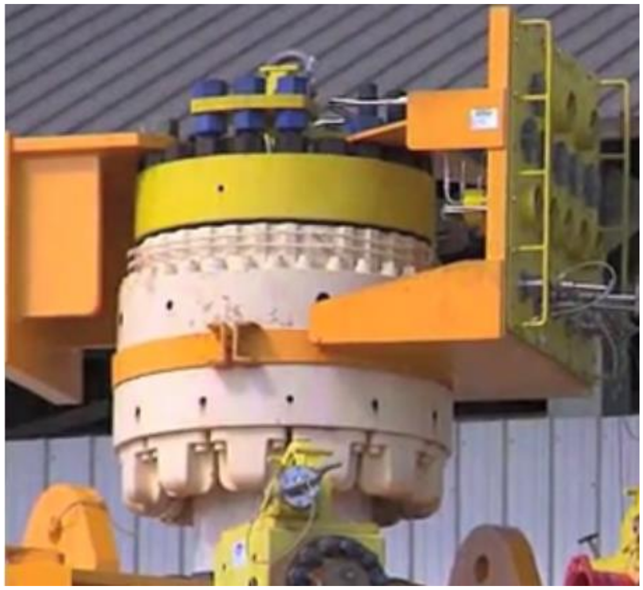


Figure 2.12: Secondary Containment Cap [2]

Wellhead Panel: The wellhead panel provides access to the ROV for operating the latching, unlatching, locking, and unlocking mechanisms of the wellhead connector. A schematic of the wellhead panel is shown in Figure 2.13.

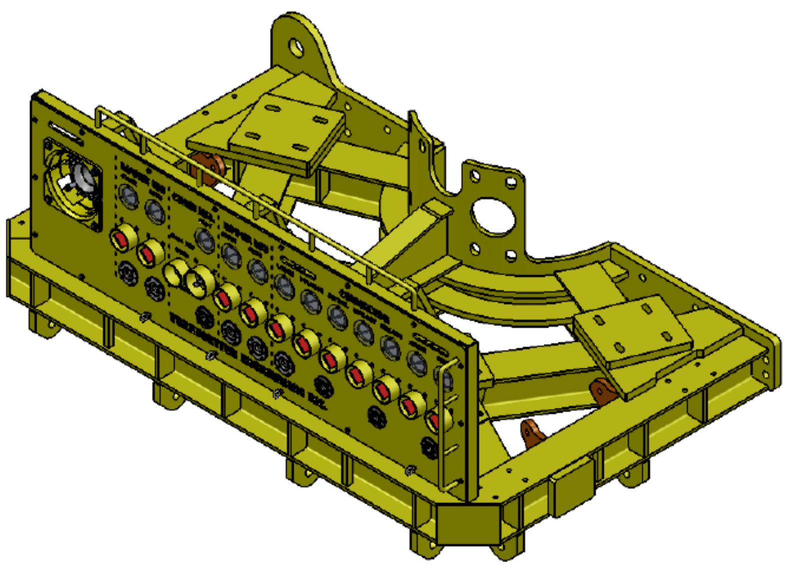


Figure 2.13: Wellhead Panel Schematic [4]

Chemical Injection Panel: The chemical injection panel shown in Figure 2.14 provides access to the ROV for the injection of hydrate inhibitors and dispersants.

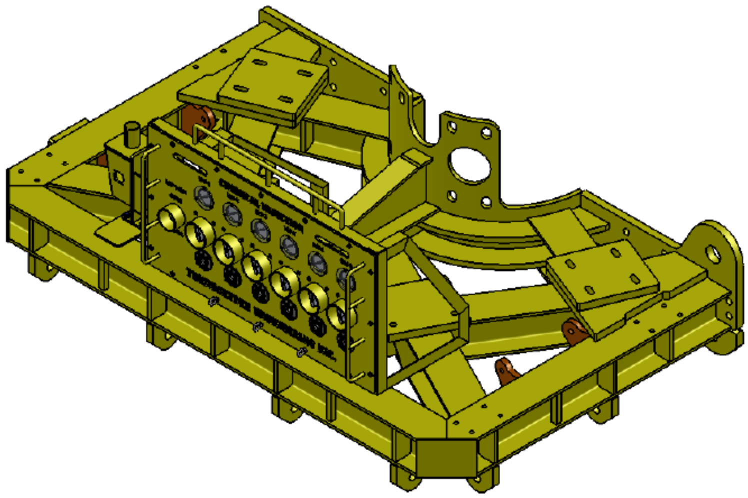


Figure 2.14: Chemical Injection Panel [4]

2.4 Well Containment Response Work Flow

2.4.1 General

This section outlines the sequence of actions and a description of the equipment used to stop or redirect the flow of hydrocarbons from an uncontrolled well. The well containment process can vary from one well to another, depending on the shut-in pressures and temperatures and the incident well conditions. The response times[4] depend on several factors such as the:

- Method of mobilization
- Equipment testing
- Availability of vessels
- Disassembly and containerizing of equipment (for air transport)
- Availability of skilled personnel

Figure 2.15 provides the well containment work flow in response to a subsea blowout. The first step is to perform a site survey and conduct an initial assessment, followed by

[4] Response time is the time needed to mobilize and deploy the system from the notification of the uncontrolled hydrocarbon release to the moment a cap or full containment system is connected to the well and is functioning.

debris removal and dispersant application operations. After the incident wellsite has been cleaned, capping equipment is deployed to shut in the flow of the well. If the wellbore pressure rises above the allowable pressure during the shut-in process, the well cannot be shut in completely, and the hydrocarbons need to be captured and collected at the surface.

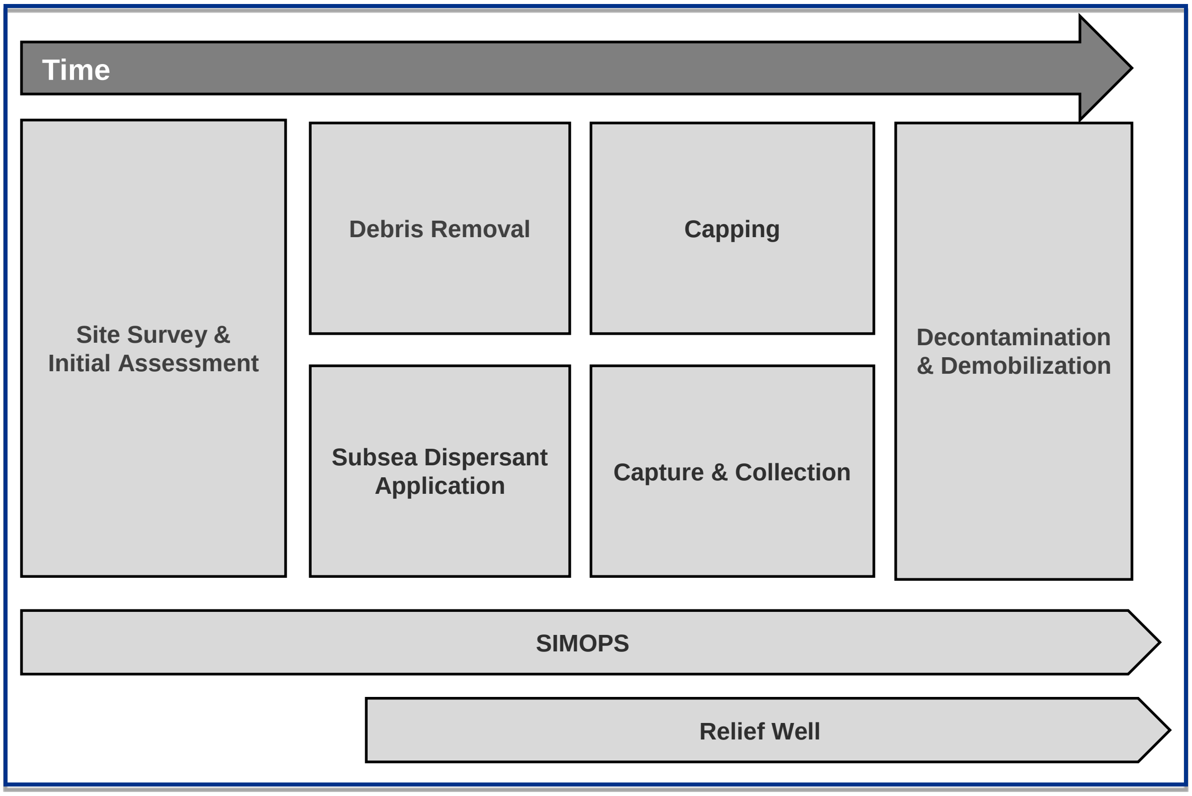


Figure 2.15: Well Containment Response Work Flow [7]

Simultaneous Operations (SIMOPS) is the management of simultaneous operations to ensure the safe execution of response activities to avoid potential clashes between activities that could bring about an undesired event. A proper SIMOPS management program involves an exchange of information to enable the efficient use of resources to accomplish multifaceted missions safely. During a response, the comprehensive SIMOPS plan includes deployment and operation of the well containment equipment.

2.4.2 Site Survey and Initial Assessment

In a well control scenario, the Operator[5] must first assess the health and safety of all personnel onboard the rig or production platform. After the wellbeing of personnel has been secured, the Operator (also called the Responsible Party [RP]) begins an in-depth assessment of the incident site.

A surface (aerial or vessel) and subsea (ROV) site survey is performed to identify the following:

- Existence of debris
- Potential discharge source(s)
- Status of surface and subsea infrastructure
- General magnitude of the release of hydrocarbons

The information obtained by the ROV site assessment is used to determine the suitable equipment for the conditions of the specific wellsite. After the site assessment is completed, the RP works with the subsea capping stack company[6] and regulators to determine the containment approach, specific equipment, and configuration needed to contain the well.

In general, one of the two containment approaches is used: cap only or cap and flow. In a cap only scenario, a subsea capping stack is attached to the incident well, and flow from the incident well is shut off through the closure of valves on the subsea capping stack's main bore and diverter outlets. In a cap and flow scenario, the subsea capping stack also redirects the flow of hydrocarbons through flexible pipes and risers to the capture vessels for processing. The selection of the subsea capping stack and subsea equipment is based on the containment approach, temperature, and pressure and the proximity to other wells and risers.

Following equipment selection, mobilization of the containment equipment and the response vessels begins.

2.4.3 Debris Removal

If debris is detected during the initial site survey, debris removal becomes critical to ensure a safe working environment and to provide access to the wellsite for intervention.

[5] In the oil and gas industry, the Operator is the company responsible for exploration, development, and production of an oil or gas well.
[6] The subsea capping stack company can be a consortium or an independent company that provides equipment, resources, and expertise for subsea well containment.

The area around the wellhead is cleared to prepare for installation of the subsea capping stack and equipment.

The debris removal tools include subsea shears, pipe grapplers, rock grapplers, chop saws, super grinders, diamond wire cutters, ROV knives, and torque tools. Shears are used for activities such as cutting a bent or broken riser and shearing a pipe. ROV utility cutting tools (for example, super grinders) are used to remove light debris and prepare the site.

The most widely used debris clearance tools are:

- Remote control unit – for remote control of pressure and flow on two independent lines that are controlled from the surface
- Impact wrench – to produce impact torque
- Hydraulic stud removal tool
- Flying Lead Orientation Tool (FLOT)
- Torque tool Class 4 – to operate rotary valves from Classes 1-4
- Dredge pump – for the disposal of sediments and gravel
- Manipulator inspection camera – for inspection in confined spaces
- 2D multibeam imaging sensor – to search and navigate in zero visibility water
- 3D multibeam imaging sensor – to produce 3D point clouds from a stationary location
- Linear Valve Override Tool (LVOT) – to use ROV hydraulics for moving a piston to actuate a gate valve stem on subsea manifolds
- Multi-purpose cleaning tools
- Pipe grappler tool, rock grappler, 22-in. chop saw, 60-in. chop saw, super grinder, diamond wire cutter, hydraulic cutter, and ROV knife

2.4.4 Subsea Dispersant Application

The ROV and other subsea systems may be used to inject the dispersant[7] directly into the hydrocarbon flow stream. A dispersant is used on the surface and subsea to break up oil and gas into smaller particles, which makes it easier for microorganisms to consume the oil and less hazardous for responding personnel on the surface. This process can minimize the amount of oil that reaches the shore and reduce environmental impact to marshes, wetlands, and beaches.

Subsea dispersants can:

[7] Additional information about dispersants can be found on Environmental Protection Agency (EPA) website (http://archive.epa.gov/bpspill/web/html/dispersants.html).

- Provide safer working conditions by reducing the exposure of surface vessels and personnel to volatile organic compounds (VOCs).
- Reduce the environmental impact of oil exposure and enhance dispersion and bio-degradation of oil in water.
- Reduce the need for surface recovery, in situ burning, and surface dispersant operations, thereby reducing the exposure of response personnel to accidents during these operations.

Dispersant is applied through coil tubing or umbilical that is connected to tanks and pumps on the vessel. Subsea dispersant equipment includes:

- Dispersant wands – to direct dispersant in a set direction.
- Dispersant wand spears (spear-type wands) – to direct dispersant in a set direction.
- A 1-in. chemical jumper – to transfer dispersant from the Coil Tubing Termination Head (CTTH) to the subsea manifold.
- Deployment rack – for transportation and storage of chemical jumpers.
- CTTH – for interfacing with two flexible lines through high flow hot stabs.
- Manifold.

2.4.5 Capping

Capping operations involve the installation of a subsea capping stack onto the wellhead/BOP and closure of the ram and choke valves to shut in the well and stop the discharge of hydrocarbons.

Based on the information gained from ROV site assessment, the subsea capping stack and the support equipment (such as the subsea hydraulic accumulator and additional connector interface adapters) are mobilized from the storage base. Pre-deployment testing is conducted at the quayside to verify the functioning and pressure integrity of the equipment. The subsea capping stack and the support equipment (such as ROV skids, accumulator module) are flown to the incident site and are deployed from the vessel to the wellhead or the BOP, depending on the incident well conditions.

The subsea capping stack vertical bore is closed, followed by the closure of valves on the diverter outlets. During the valve closure process, the shut-in pressure in the well is monitored. If the pressures are higher than the maximum allowable pressure, the valve closure process must be stopped because the well equipment may not be able to withstand the pressures. This may cause a rupture below the seafloor, which can be difficult to contain.

Currently available subsea capping stacks can both seal the well and redirect the flow of fluids through flexible pipes and risers to the capture vessels.

2.4.6 Capture and Collection

If for any reason the capping of an uncontrolled well does not succeed in stopping the flow of hydrocarbons, a capture and collection system must be used. Capture and collection systems (also called containment systems) are used to capture, collect, and transport escaping hydrocarbons from the subsea well to the surface for storage and disposal. The capture and collection system includes the following equipment:

- Surface containment vessels – store and process captured hydrocarbons
- Umbilical Termination Assembly – controls the subsea capping stack and provides real time data about the well
- Subsea Umbilicals, Risers, and Flowlines (SURF) equipment – connects the subsea equipment to the topside equipment
- Subsea systems and infrastructures (for example, manifolds, flexible flowlines, Pipeline End Termination [PLET]) – route hydrocarbons from the subsea capping stack to the riser
- Subsea Dispersant System – injects dispersants to mitigate hydrocarbons in water
- Hydrate Inhibition System – prevents hydrate formation within the subsea equipment
- Top Hat or Containment Dome – captures leaking fluid that is vented from the incident well

If a subsea capping stack cannot make a successful connection with the wellhead (because of damage to the wellhead), a containment dome can be used to capture the hydrocarbons flowing to the environment. A containment dome is an unpressurized structure that is placed over damaged or faulty subsea equipment to collect leaking hydrocarbons. Containment domes are also referred to as ‘cofferdams’ or ‘hats.’

Hydrate inhibition systems are typically used in conjunction with the well containment systems to prevent subsea oil from freezing up and forming hydrates that can clog tubes that collect and route oil and gas to the surface. Methanol or glycol solutions are used to prevent potential hydrate formation and blockage.

2.4.7 Relief Well

As the well containment operations are taking place, SIMOPS are performed to drill a relief well. A relief well is a secondary well that is drilled with the intent of intersecting the target well at some pre-determined distance below the seabed. The location of the relief well must be at a minimum safe distance from the incident wellsite so as to ensure safe relief drilling operations and avoid interference with the well containment operations. The purpose of the relief well is to permanently kill the incident well by pumping salt water, mud, and concrete into the incident well.

Aside from the directional (angled) drilling required to drill a relief well, there is no difference between drilling a relief well and a regular well. Figure 2.16 provides the schematic of the two relief wells that were drilled to kill the Macondo well in 2010.

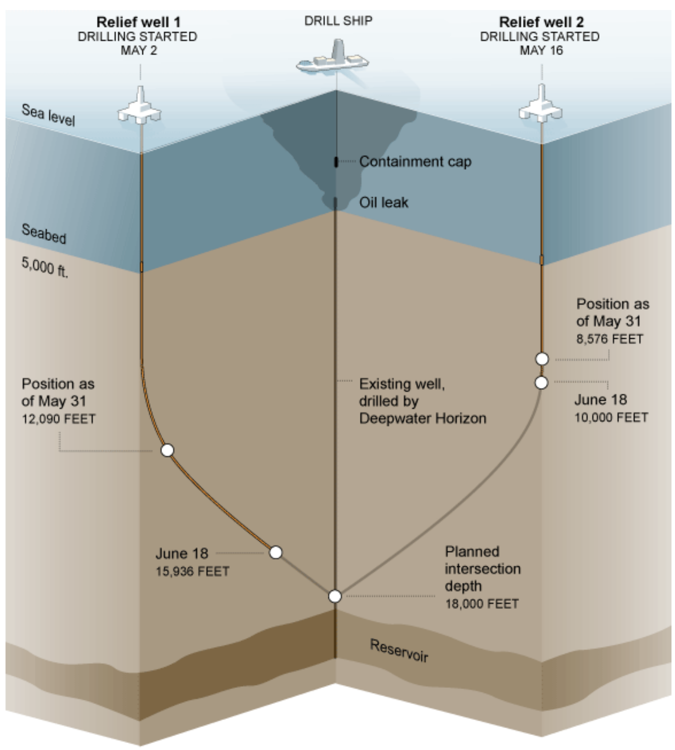


Figure 2.16: Schematic of Relief Well Drilled During the 2010 Macondo Incident [8]

This report focuses on the technical capabilities and availability of subsea capping stacks and does not provide details of the capture and collection systems or relief well operations.

3.0 Available Subsea Capping Stacks and their Technical Capabilities

3.1 Introduction

This section provides a brief history of subsea capping stacks and reviews industry-owned consortiums and their capabilities for responding to well control events. In addition, the subsea capping stacks that are available globally are enumerated and their technical capabilities, storage locations, and serving regions are provided.

3.2 Subsea Capping Stacks Consortiums and Organizations

Following the Macondo incident in 2010, the U.S. federal government enacted a drilling moratorium that halted drilling activity in the Gulf of Mexico (GOM)[8]. During this time, the industry recognized the need to improve containment capabilities and emergency response protocols. As a result, U.S. oil companies formed two cooperative containment groups—Marine Well Containment Company (MWCC) and HWCG LLC (formerly called the Helix Well Containment Group)—to develop and maintain the equipment and procedures needed during uncontrolled well flowing conditions. The drilling moratorium was lifted in October 2010.

U.S. regulations became more stringent and required oil companies to have access to capping and containment equipment and relief rigs and the expertise to stop or redirect the flow of hydrocarbons during a well control incident. U.S. regulators made this requirement mandatory for issuing permits to drill in the GOM.

MWCC and HWCG LLC maintain the subsea capping stacks and containment equipment in a response-ready state, and they develop generic installation and operational procedures. They also support well permitting by providing system documentation to member companies to develop their permit applications to BSEE. A detailed description of these companies is provided in Sections 3.2.1 and 3.2.2.

Regulators and oil companies around the world have also started evaluating their drilling and incident response procedures. Oil & Gas UK[9] established the Oil Spill Prevention and Response Advisory Group (OSPRAG) to review industry practices for the United Kingdom Continental Shelf (UKCS).

[8] GOM in this report refers to U.S. Gulf of Mexico Outer Continental Shelf
[9] Oil & Gas UK is the leading trade association for the United Kingdom offshore oil and gas industry. It has been established on the foundation of the UK Offshore Operators Association. The association is the leading representative body for the U.K. offshore oil and gas industry.

In November 2010, Oil & Gas UK procured a subsea capping stack for the UKCS, including the west of Shetland. The OSPRAG Technical Review Group, working with BP, oversaw the design and development of this subsea capping stack.

In response to the April 2010 Macondo incident in the GOM and other similar incidents that preceded it, the International Association of Oil & Gas Producers (IOGP)[10] formed the Global Industry Response Group (GIRG). GIRG was tasked with examining the industry's capability to respond to a major well control incident and identifying areas for improvement. GIRG did this by identifying and gathering work performed by IOGP's member companies and national regulators in response to the Macondo and Montara[11] oil spills and other well control incidents.

The three groups that IOGP formed to respond to GIRG's recommendations were:

- The Wells Expert Committee – with a focus on incident prevention
- The Oil Spill Response Joint Industry Project – to work with the API to evaluate recommendations and enhance coordination on oil spill response
- The Subsea Well Response Project (SWRP) – consortium to deliver improved capping response in support of containment solutions [9]

SWRP was launched in May 2011 and is a joint non-profit initiative of eight major oil and gas companies (BG Group, BP, Chevron, ConocoPhillips, ExxonMobil, Shell, Statoil, Total) that are working together to enhance the industry's capacity to respond to subsea well control incidents. SWRP collaborates with Oil Spill Response Limited (OSRL) to maintain and store well containment equipment at multiple global locations. Members can mobilize and deploy this equipment in the event of an incident. OSRL is owned by 45 member companies and supports 100 associate members.

Wild Well Control (WWC), an independent firefighting and well control services company, formed the WellCONTAINED consortium with 41 member companies and owns two subsea capping stacks that can be deployed internationally.

Some of the major oil companies, such as Shell and BP, also own subsea capping stacks in various regions around the world. These subsea capping stacks are built for their specific needs and may not be available for use by other Operators.

[10] IOGP is a global forum in which members identify and share best practices to achieve improvements in health, safety, environment, security, social responsibility, engineering, and operations.
[11] The Montara oil spill was an oil and gas leak that took place in the Montara oil field in the Timor Sea, off the northern coast of Western Australia. The well continued leaking for 74 days before it was stopped by pumping mud into the well and the wellbore cemented.

3.2.1 Marine Well Containment Company

In July 2010, four major oil and gas Operators (Shell, Chevron, ConocoPhillips, and ExxonMobil) formed the MWCC to provide containment response capability for the GOM.

Other major oil companies (Anadarko, Apache, BHP Billiton, BP, Hess, and Statoil) have also joined MWCC, and it currently has ten member companies.

MWCC also provides coverage for non-member Operators on a per-well basis [2].

MWCC is responsible for the following functions:

- Support well permitting by providing system documentation. Member companies use the documentation to develop their permit submissions, including generic procedures for containment preparation, to BSEE.
- Maintain equipment in a response-ready state
- Provide regular training and drills to member companies to ensure that they are ready to respond
- Develop and maintain generic installation and operational procedures
- Maintain dispersant stock piles and contracts to be ready to respond
- Capture lessons learned and oversee the refurbishment and return of MWCC equipment to storage locations as a follow-up to any incident

MWCC has a full-time staff of about 70 people who have Operator and service company experience, many of whom worked on the containment of the Macondo well. MWCC also has 100 reservists (Reservist Response Team) who are employed by Wood Group PSN, a division of Wood Group. These personnel, who operate platforms throughout the GOM, are fully trained in containment equipment operations. In the event of an incident, they will be mobilized to respond. MWCC works with regulators from BSEE and the U.S. Coast Guard to ensure that all expectations are met.

3.2.1.1 MWCC Equipment and Capabilities

MWCC equipment is available for use in the deep water[12] GOM in depths from 500 ft. to 10,000 ft., temperatures up to 350°F, and pressures up to 15,000 pounds per square inch (psi). The system can cap only or cap and flow an incident well, and it has the capability to process up to 100,000 barrels of liquid per day and up to 200 million cubic feet of gas per day. Additionally, MWCC can store up to 700,000 barrels of liquid in each of its two modular capture vessels (MCVs). The liquid is then brought onshore by shuttle

[12] Water depth greater than 500 ft. is considered 'deep water.'

tankers for further processing. The organization's two MCVs provide lightering[13] service in the GOM and can be mobilized to MWCC's shore base, within five to eight days, to be configured for capture operations.

Currently, MWCC owns the following equipment:

- Debris removal, subsea dispersant, and hydrate inhibition equipment
- Three subsea capping stacks and supporting equipment
- Containment system (for example, two MCVs, subsea structures, SURF equipment)

The Subsea Accumulator Module (SAM) provides high pressure hydraulic fluid to operate the subsea capping stack and also serves to maintain hydraulic control system pressure. Figure 3.1 shows the MWCC Subsea Accumulator Module.

Figure 3.1: MWCC Subsea Accumulator Module [2]

3.2.1.2 Subsea Capping Stack Technical Specifications

MWCC tests and maintains the subsea capping stacks in a constant state of readiness with the help of third party contractors. The three MWCC subsea capping stacks are:

- Subsea Containment Assembly (SCA)
- 15k psi subsea capping stack
- 10k psi subsea capping stack

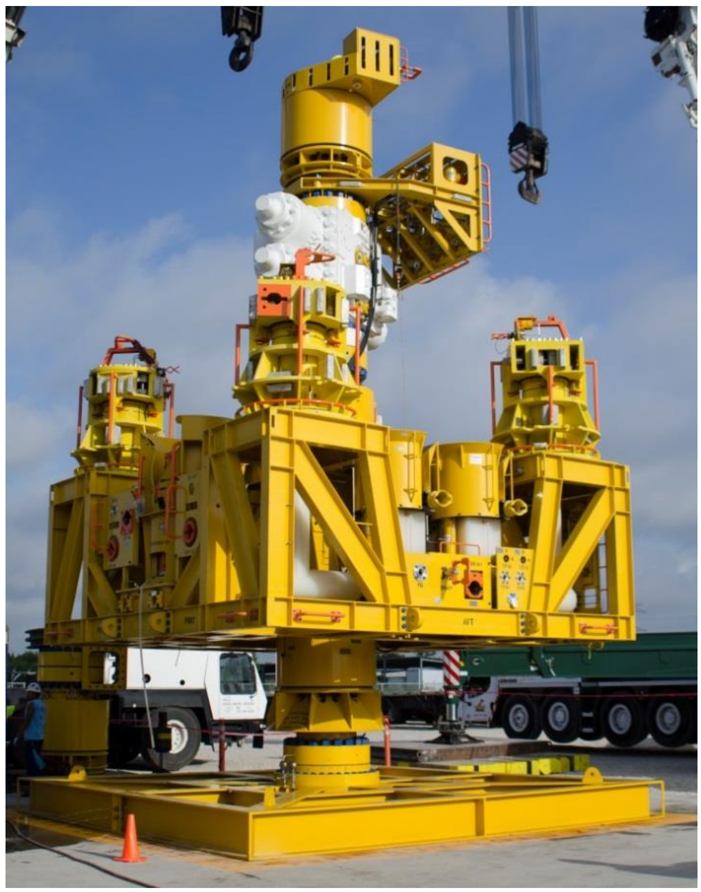
All three subsea capping stacks provide a dual barrier of the BOP ram and a secondary containment cap.

[13] Lightering is the process of transferring cargo between vessels of different sizes, usually between a barge and oil tanker. Lightering is undertaken to reduce a vessel's draft so as to enter port facilities that cannot accept very large ocean-going vessels.

The SCA is primarily used in cap and flow scenarios. The SCA's design allows the subsea capping stack to be disassembled into two sub-assemblies, which facilitates handling and transportation. It has full electro-hydraulic (EH) control capability, which allows operation from the top sides. Table 3.1 provides the technical specifications of the SCA.

Table 3.1: MWCC SCA Technical Specifications [10]

MWCC Subsea Containment Assembly (SCA)	
Parameter	**Value**
Manufacturer	Aker Solutions
Primary Bore	18-3/4 in. with dual rams
Diverter Outlets	(4) 5-1/8 in. with dual gate valves
Pressure Rating	15,000 psi
Temp. Rating	250°F
Water Depth	10,000 ft.
Soft Shut-in Capability	Yes – with 4 chokes
Flow Back Capability	Yes – 100,000 bpd
Chemical Injection	Yes – Hydrate remediation/dispersant
Controls	EH-MUX and ROV
Installation Method	Drill Pipe or Wire
Weight/Air Freight	170 tons/No
Dimensions (LxWxH)	—
Storage Location	Ingleside, Texas
Serving Region	GOM



The 15k psi subsea capping stack is the only capping stack that is capable of handling temperatures up to 350°F, and it can be used to cap only or cap and flow wells. This subsea capping stack was used in the deployment demonstration to BSEE in 2012. Table 3.2 provides the technical specifications of the 15k psi subsea capping stack.

Table 3.2: MWCC 15k psi Subsea Capping Stack Technical Specifications [10]

MWCC 15k psi Subsea Capping Stack		
Parameter	**Value**	
Manufacturer	Trendsetter Engineering	
Primary Bore	18-3/4 in. with single ram	
Diverter Outlets	(4) 5-1/8 in. with dual gate valves	
Pressure Rating	15,000 psi	
Temp. Rating	350°F	
Water Depth	10,000 ft.	
Soft Shut-in Capability	Yes – with 2 chokes	
Flow Back Capability	Yes – 100,000 bpd	
Chemical Injection	Yes – Hydrate remediation/dispersant	
Controls	ROV with Subsea Accumulator Module	
Installation Method	Drill Pipe or Wire	
Weight/Air Freight	93 tons/No	
Dimensions (LxWxH)	11.5 x 11.5 x 18.5 ft.	
Storage Location	Ingleside, Texas	
Serving Region	GOM	

The 10k psi subsea capping stack will be used mainly in cap only scenarios in which well casings and riser systems are closely spaced, such as Tension-Leg Platform (TLP) and spar applications where wells are located beneath a floating production facility. Table 3.3 provides the technical specifications of the 10k psi subsea capping stack.

Table 3.3: MWCC 10k psi Subsea Capping Stack Technical Specifications [10]

MWCC 10k psi Subsea Capping Stack		
Parameter	**Value**	
Manufacturer	Trendsetter Engineering	
Primary Bore	7-1/16 in. with dual rams	
Diverter Outlets	(2) 4-in. with single gate valves	
Pressure Rating	10,000 psi	
Temp. Rating	300°F	
Water Depth	10,000 ft.	
Soft Shut-in Capability	Yes – with 2 chokes	
Flow Back Capability	Yes	
Chemical Injection	Yes – Hydrate remediation/dispersant	
Controls	ROV with Subsea Accumulator Module	
Installation Method	Wire	
Weight/Air Freight	50 tons/No	
Dimensions (LxWxH)	9 x 9 x 18.25 ft.	
Storage Location	Ingleside, Texas	
Serving Region	GOM	

3.2.1.3 *Storage Locations*

The three MWCC subsea capping stacks are stored at a shore base in Ingleside, Texas. Figure 3.2 shows the location of the capping stacks on a world map.

Throughout this report, the subsea capping stacks that serve the region around its storage area only are called ‘local’ subsea capping stacks. The local subsea capping stacks are transported by sea and typically reach the incident site in 24–48 hours. The subsea capping stacks that serve globally and can be transported by air called the ‘global’ subsea capping stacks. Transport of the global subsea capping stacks may require up to 14 days, depending on the location of the incident site.

Figure 3.2: MWCC Subsea Capping Stack Storage Location

3.2.2 HWCG LLC

HWCG LLC is the second consortium that has been formed to support operations in the GOM. The member companies of the consortium are shown in Table 3.4.

Table 3.4: Member Companies of HWCG LLC

• Bennu Oil & Gas, LLC • Cobalt International Energy, Inc. • Deep Gulf Energy LP • ENI U.S. Operating Company Inc. • EnVen Energy Ventures, LLC • Energy Resource Technology GOM, Inc. • Freeport-McMoRan Oil & Gas LLC • LLOG Exploration Company, LLC	• Marathon Oil Company • Marubeni Oil & Gas (USA) Inc. • Murphy Exploration & Production Company (USA) • Noble Energy Services, Inc. • Repsol Services Company • Stone Energy Corporation • Walter Oil & Gas Corporation • W&T Offshore, Inc.

HWCG LLC is responsible for the following functions:

- Supports well permitting by providing documentation for the member companies to develop their APDs that are submitted to BSEE
- Works with subcontractors to maintain equipment in a response-ready state
- Conducts periodic subsea incident response drills with member companies
- Captures lessons learned as a follow-up to any incident

As part of the Mutual Aid program, HWCG LLC is provided with 12 personnel from each member company to respond to a well control incident. The periodic response drills include coordinating detailed plans for well containment operations to train personnel to be ready to respond. HWCG LLC works with regulators from BSEE and the U.S. Coast Guard to ensure that all expectations are met.

3.2.2.1 HWCG LLC Equipment and Capabilities

Along with owned assets, HWCG LLC maintains agreements with eleven service companies. HWCG LLC also maintains 30 other service providers to provide equipment and personnel that would be useful during a subsea blowout response. HWCG LLC manages the logistics, planning, and facilitation of deep water incident response.

The HWCG LLC response system builds on the equipment used in the containment of the Macondo well, including the Helix Fast Response System (HFRS) with the Q4000 intervention vessel and the Helix Producer 1 from Helix Energy Solutions Group (HESG).

Current HWCG LLC well containment systems include [11]:

- The ability to fully operate in water depths of up to 10,000 ft.
- Two dual ram subsea capping stacks: 15,000 psi and 10,000 psi
- The ability to capture and process 130,000 barrels of oil per day and 220 million cubic feet of gas per day

3.2.2.2 Subsea capping stack Technical Specifications

HWCG LLC has access to two subsea capping stacks:

1. A 13-5/8-in. 10,000 psi subsea capping stack, which is owned and maintained by HESG
2. An 18-3/4-in. 15,000 psi subsea capping stack, which is owned and maintained by Trendsetter Engineering

Table 3.5 provides the technical specifications and a picture of the 10k psi subsea capping stack. Table 3.6 provides the technical specifications and a picture of the 15k psi subsea capping stack.

Table 3.5: HWCG LLC 10k psi Subsea Capping Stack Technical Specifications

HWCG LLC 10k psi Subsea Capping Stack		
Parameter	**Value**	
Manufacturer	Worldwide Oilfield Machine (WOM)	
Primary Bore	13-5/8 in. with dual rams	
Diverter Outlets	(2) 5-1/8 in. with dual gate valves	
Pressure Rating	10,000 psi	
Temp. Rating	250°F	
Water Depth	10,000 ft.	
Soft Shut-in Capability	Yes	
Flow Back Capability	Yes	
Chemical Injection	Yes – Hydrate remediation/dispersant	
Controls	ROV with Subsea Accumulator Module	
Installation Method	Drill pipe or Wire	
Weight/Air Freight	72 tons/No	
Dimensions (LxWxH)	—	
Storage Location	Ingleside, Texas	
Serving Region	GOM	

Table 3.6: HWCG LLC 15k psi Subsea Capping Stack Technical Specifications

HWCG LLC 15k psi Subsea Capping Stack

Parameter	Value
Manufacturer	Trendsetter Engineering
Primary Bore	18-3/4 in. with dual rams
Diverter Outlets	(2) 5-1/8 in. with single gate valves
Pressure Rating	10,000 psi
Temp. Rating	350°F
Water Depth	15,000 ft.
Soft Shut-in Capability	Yes – with 2 chokes
Flow Back Capability	Yes
Chemical Injection	Yes – Hydrate remediation/dispersant
Controls	ROV with Subsea Accumulator Module
Installation Method	Drill Pipe or Wire
Weight/Air Freight	76 tons/No
Dimensions (LxWxH)	11.5 x 11.5 x 19 ft.
Storage Location	Houston, Texas
Serving Region	GOM

3.2.2.3 Storage Location

The HWCG LLC 10k psi subsea capping stack is stored in Ingleside, Texas. The 15k psi subsea capping stack is stored in Houston, Texas. Figure 3.3 shows the HWCG LLC subsea capping stack storage locations on the world map.

Figure 3.3: HWCG LLC Subsea Capping Stack Storage Location

3.2.3 Oil Spill Prevention and Response Advisory Group

After the 2010 Macondo oil spill, the U.K. oil and gas industry and its regulators and trade unions collaborated to establish the Oil Spill Prevention and Response Advisory Group (OSPRAG). OSPRAG includes senior representatives from the U.K.'s regulators, trade unions, the Maritime & Coastguard Agency (MCA), and the Secretary of State's Representative for Maritime Salvage and Intervention (SOSREP).

OSPRAG performed a thorough review of drilling practices in the UKCS to ensure safety during drilling operations and to enhance existing spill prevention and response mechanisms. OSPRAG identified and recommended improvements to further strengthen the U.K.'s ability to respond to a well control incident. As a result, the OSPRAG subsea capping stack is designed to seal off an uncontrolled well.

OSRL owns and maintains the OSPRAG subsea capping stack and provides access to the member companies who operate within the UKCS through a supplemental agreement [12].

3.2.3.1 OSPRAG Subsea Capping Stack Technical Capabilities

The OSPRAG subsea capping stack can be quickly deployed [13]:

- At the widest possible range of wells and oil spill scenarios that could occur in the UKCS, including West of Shetland.

- At water depths of between 328 ft. and 10,000 ft.
- In wave heights of up to 16 ft.
- From a wide variety of multi-service vessels or drilling rigs.
- To wells up to 15,000 psi and 250°F.
- Onto a flowing well up to 75,000 barrels a day.

Table 3.7 provides the technical specifications of the OSPRAG subsea capping stack.

Table 3.7: OSPRAG Subsea Capping Stack Technical Specifications [13]

OSPRAG Subsea Capping Stack	
Parameter	**Value**
Manufacturer	Cameron Ltd.
Primary Bore	5-1/8 in. with gate valves
Diverter Outlets	5-1/8 in. with dual gate valves
Pressure Rating	15,000 psi
Temp. Rating	250°F
Water Depth	10,000 ft.
Soft Shut-in Capability	Yes
Flow Back Capability	Yes – 75,000 bpd
Chemical Injection	Yes – Hydrate remediation/dispersant
Controls	ROV
Installation Method	Wire
Weight/Air Freight	43.8 tons/No
Dimensions (LxWxH)	13 x 15 x 15 ft.
Storage Location	Aberdeen, Scotland
Serving Region	UKCS, including West of Shetland

3.2.3.2 Storage Locations

The OSPRAG subsea capping stack is stored in Aberdeen, Scotland. Figure 3.4 shows the location of this subsea capping stack on a world map.

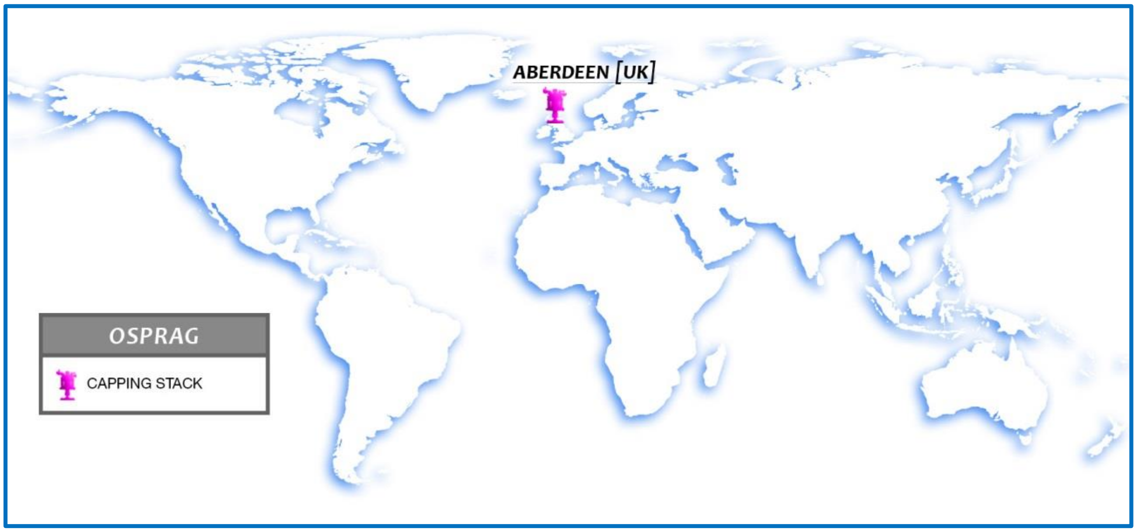


Figure 3.4: OSPRAG Subsea Capping Stack Storage Location

3.2.4 Subsea Well Response Project/Oil Spill Response Limited

SWRP collaborates with OSRL to develop capping and containment systems. OSRL has developed international base locations and has made containment equipment available for the international industry [4].

Subsea Well Intervention Services (SWIS) is OSRL's dedicated subsea division, and it provides OSRL members with the opportunity to access a full subsea intervention capability (dispersant, capping, and containment). OSRL SWIS owns, maintains, and stores the equipment in a response-ready state at different strategic locations around the world [4].

3.2.4.1 OSRL Capabilities

The OSRL SWIS equipment includes:

- Two Subsea Incident Response Toolkits (SIRTs).
- Four subsea capping stacks.
- A Containment Toolkit [14].

The equipment is transportable by land, air, and sea and can be used by OSRL members through supplementary agreements. The equipment is strategically stored around the globe for efficient deployment.

The SIRTs are stored at the Oceaneering facilities in Stavanger, Norway, and Macae, Brazil. The SIRTs are split into three main systems:

1. Debris Clearance System: This system consists of various tools to allow access for dispersant applications and work on BOPs. The system also includes tools for site surveys before the work begins, including torque tools, cutting tools, and grappling tools. Figure 3.5 provides a schematic of the OSRL debris clearance system.

Figure 3.5: Schematic of OSRL Debris Clearance System [15]

2. Subsea Dispersant System: This system allows for the subsea application of oil dispersant[14] at the wellhead. This will create safer surface working conditions for response personnel and will enhance oil degradation. This system includes dispersant wands, a CTTH, jumpers to transfer dispersant from the CTTH to the subsea manifold, deployment racks for flying leads, and a manifold. Figure 3.6 provides the schematic of the OSRL subsea dispersant system.

[14] OSRL is implementing a global stockpile of 5000 m^3 of dispersant on behalf of the members. The dispersant stockpile is stored at various locations to enable quick access and ensure availability of sufficient stock. If necessary, 100% of the stockpile can be mobilized to an individual incident.

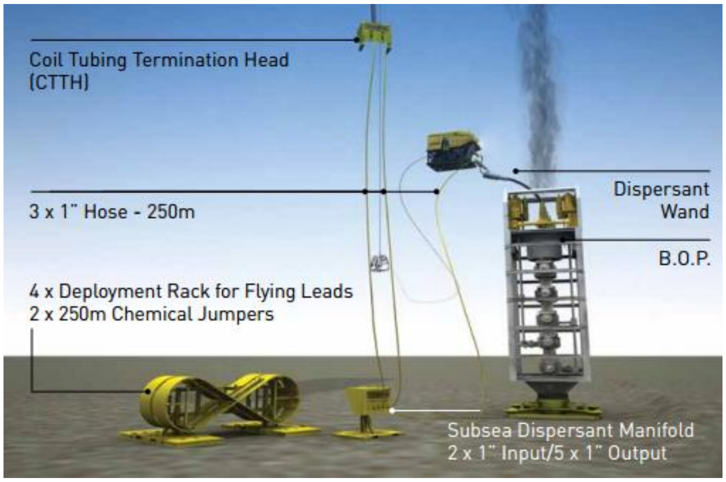


Figure 3.6: Schematic of OSRL Subsea Dispersant System [15]

3. BOP Intervention Equipment: In the unlikely event that the rig fails to close the BOP, emergency BOP intervention is required. The components of the intervention equipment include ROV-mounted intervention charging skids, high pressure accumulators, and a BOP intervention manifold. Figure 3.7 provides a schematic of the OSRL BOP intervention system.

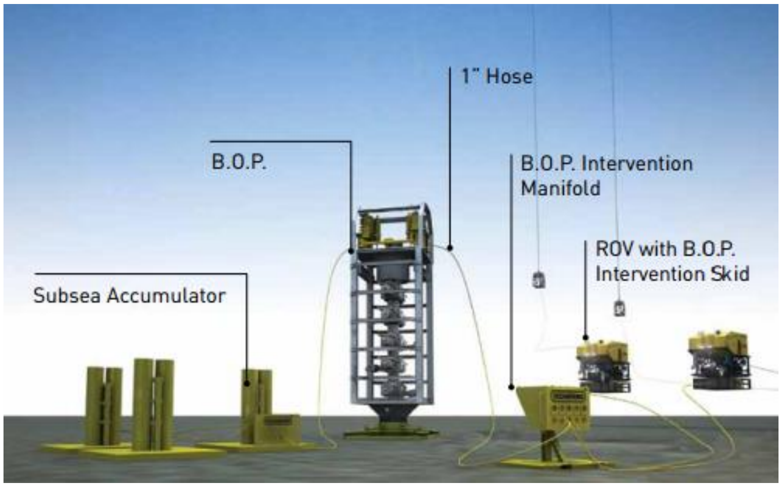


Figure 3.7: Schematic of OSRL BOP Intervention System [15]

These three systems are packed separately and can be used independently of each other. During a subsea well incident, Oceaneering will work with OSRL to mobilize the SIRT and will act as a point of contact for technical inquiries.

During a subsea well response incident, Trendsetter Engineering prepares the subsea capping stack system for deployment by performing the following tasks:

- Mobilize engineers to the location of the chosen subsea capping stack system.
- For sea mobilization – run pre-deployment tests
- For air mobilization – dismantle and pack the subsea capping stack into containers
- Send engineers to the in-country port to reassemble and run pre-deployment tests, subject to a separate contract with the Incident Owner
- Act as an in-country point of contact for technical enquiries

The Containment Toolkit [14] is stored in containers at warehouses and is ready to be transported to the nominated delivery point. Parts of the Containment Toolkit are strategically stored in Brazil, Norway, the U.K., and the U.S. All equipment is transportable by sea and air except for the flexible flowlines and jumpers, which are stored on reels and are transportable only by sea. Figure 3.8 shows the storage locations of various items of equipment that are part of the Containment Toolkit. Because the flexible flowlines and jumpers are not air transportable, they are stored at various locations around the world to enable faster response during a flowing well scenario.

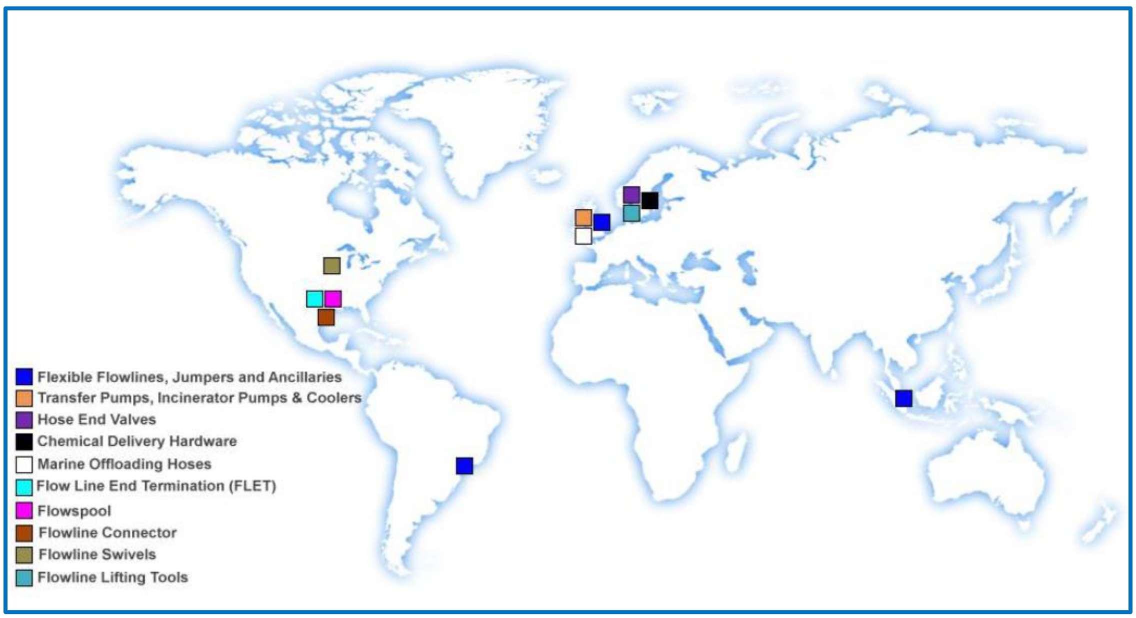


Figure 3.8: OSRL Global Containment Equipment Locations [16]

3.2.4.2 Subsea Capping Stack Technical Specifications

The subsea capping stacks are designed and optimized to operate in a variety of conditions around the world. As a result of the different scenarios, OSRL's equipment is designed to be adaptable and easily reconfigurable to address the majority of scenarios in which incidents might arise.

The equipment includes four subsea capping stacks:

- Two 18-3/4 in. bore subsea capping stacks, which were developed to handle pressures up to 15,000 psi
- Two 7-1/16 in. bore subsea capping stacks, which were designed for pressures up to 10,000 psi.

All four subsea capping stacks are designed from one common structure, which provides greater component compatibility and flexibility to handle a variety of scenarios. They have common pipe work, valves, chokes, and spools, all of which are rated to 15,000 psi. The key difference is the use of 7-1/16 in. 10,000 psi gate valves for the 10,000 psi stacks and 18-3/4 in. 15,000 psi rams for the 15,000 psi stacks. Table 3.8 and Table 3.9 provide the technical specifications of the 15k psi and 10k psi subsea capping stacks, respectively.

Table 3.8: OSRL 15k psi Subsea Capping Stack Technical Specifications [17]

Two OSRL 15k psi Subsea Capping Stacks		
Parameter	**Value**	
Manufacturer	Trendsetter Engineering	
Primary Bore	18-3/4 in. with dual rams	
Diverter Outlets	(4) 5-1/8 in. with dual gate valves	
Pressure Rating	15,000 psi	
Temp. Rating	302°F	
Water Depth	10,000 ft.	
Soft Shut-in Capability	Yes – with 4 chokes	
Flow Back Capability	Yes – 100,000 bpd	
Chemical Injection	Yes – Hydrate remediation/dispersant	
Controls	ROV with Subsea Accumulator Module	
Installation Method	Drill Pipe or Wire	
Weight/Air Freight	120 metric tons/Yes	
Dimensions (LxWxH)	15.4 x 13.6 x 19 ft.	
Storage Location	Norway, Brazil	
Serving Region	Worldwide (except GOM)	

Table 3.9: SWRP 10k psi Subsea Capping Stack Technical Specifications [17]

Two OSRL 10k psi Subsea Capping Stacks		
Parameter	**Value**	
Manufacturer	Trendsetter Engineering	
Primary Bore	7-1/16 in. with dual gate valves	
Diverter Outlets	(4) 5-1/8 in. with dual gate valves	
Pressure Rating	10,000 psi	
Temp. Rating	302°F	
Water Depth	10,000 ft.	
Soft Shut-in Capability	Yes – with 4 chokes	
Flow Back Capability	Yes – 100,000 bpd	
Chemical Injection	Yes – Hydrate remediation/dispersant	
Controls	ROV	
Installation Method	Drill Pipe or Wire	
Weight/Air Freight	90 metric tons/Yes	
Dimensions (LxWxH)	15.4 x 13.6 x 17.3 ft.	
Storage Location	Singapore, South Africa	
Serving Region	Worldwide (except GOM)	

3.2.4.3 Storage Locations

The four SWRP subsea capping stacks are stored at different OSRL locations around the world:

1. Norway – 15k psi subsea capping stack
2. Brazil – 15k psi subsea capping stack
3. South Africa – 10k psi subsea capping stack
4. Singapore – 10k psi subsea capping stack

The SIRTs are stored at the Oceaneering facilities in Stavanger, Norway and Macae, Brazil. Figure 3.9 shows the storage locations of the OSRL subsea capping stacks, the SIRTs, and the containment toolkits.

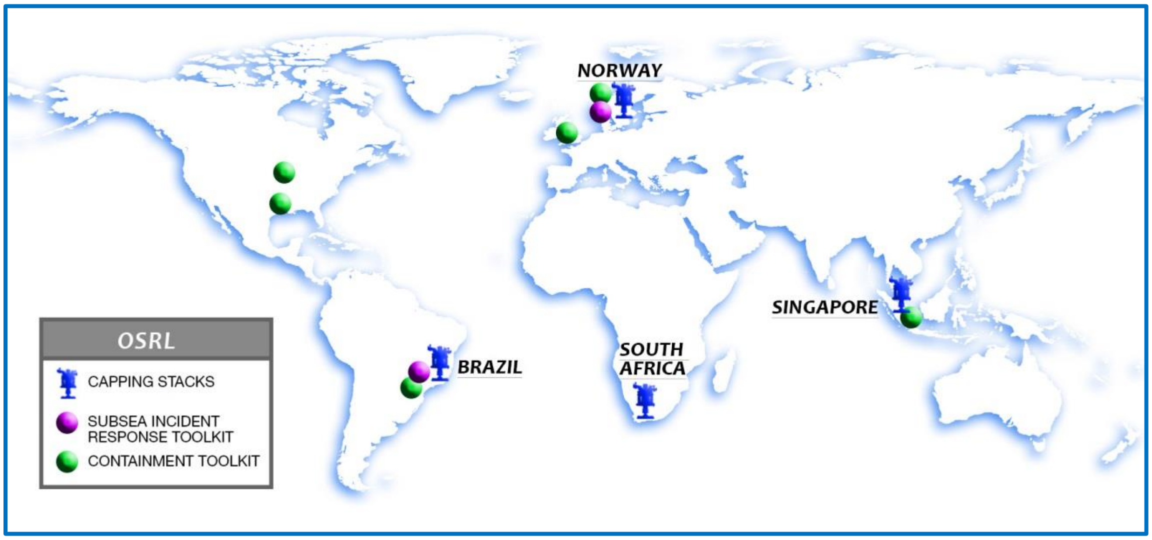


Figure 3.9: OSRL Capping and Containment System Storage Locations

3.2.5 WellCONTAINED

WellCONTAINED is a consortium from Wild Well Control that has 41 member companies providing global emergency response solutions. WellCONTAINED provides member companies access to subsea capping stacks as well as technical planning, advanced engineering, and response training.

The companies listed in Table 3.10 are members of the WellCONTAINED consortium [18].

Table 3.10: Companies in the WellCONTAINED Consortium

• AWE Limited • Apache Corporation • Anadarko Petroleum Corporation • BG Group • BR Petrobras • China National Offshore Oil Corporation • Cobalt International Energy • ConocoPhillips • Detnorske • ENI S.p.A. • E.ON UK plc • Exxon Mobil Corporation • Faroe Petroleum • Freeport-McMoran, Inc.	• GDF Suez (now ENGIE Group) • Hess Corporation • Inpex Corporation • JSC Zarubezhneft • JX Nippon Oil & Energy • Karoon Gas Peru • Kosmos Energy • LUKOIL Oil Company • Lundin Petroleum • Maersk Oil • Niko Resources Ltd • Murphy Exploration & Production Co. • Norwegian Energy Company ASA (NORECO) • OMV Aktiengesellschaft	• PDVSA • Pemex • PETRONAS • Premier Oil plc • Queiroz Galvão Group • Repsol • Statoil ASA • Talisman Energy • Total • Tullow Oil plc • VNG Norge AS • Wintershall Holding GmbH • Woodside

3.2.5.1 WellCONTAINED Capabilities

The response equipment comprises four basic modules [19]:

- Debris removal
- Subsea dispersant application
- Subsea Hydraulic Power Unit (HPU)
- Subsea capping stack

The debris removal package contains two sizes of subsea shears that provide cutting capability of tubular and structural members up to 46 in. The shears can be used to cut bent or broken risers or shear pipe and can clear areas in preparation for subsea capping stack installation. In addition to the shears, ROV utility cutting tools, such as the Super Grinder, are part of the kit and can be used for light debris removal and site preparation for the subsea capping stack installation. Figure 3.10 shows the shears positioned to cut a pipe.

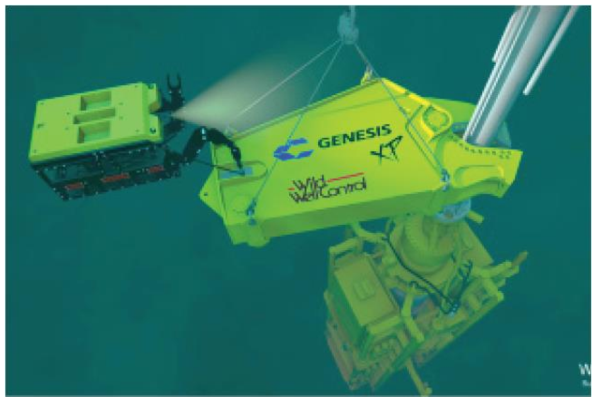


Figure 3.10: Shears Positioned to Cut the Riser [18]

The subsea dispersant application package includes all required hardware to facilitate the application of dispersants subsea from the RP-provided coiled tubing unit through application wands or ROV hot stabs. Key components include a coiled tubing routing manifold, a subsea distribution manifold, and a subsea hose deployment reel with more than 3,000 ft. of hose. The system is rated to 4,500 psi and may also be used to convey hydrate inhibition and remediation chemicals as well as to control line fluids.

The subsea HPU provides localized hydraulic power to equipment that may be used during the response operation. The different subsea HPU options include having a dedicated subsea hydraulic power unit system as well as ROV-deployable hydraulic skids. The HPU can also be used to perform secondary operation of the BOP.

3.2.5.2 Subsea Capping Stack Technical Specifications

The two subsea capping stacks facilitate the installation chokes for soft shut-in operations or gooseneck assemblies for extended flowback/well kill operations. The subsea capping stack also features chemical injection (dispersant or hydrate mitigation/remediation) as well as internal pressure and temperature monitoring capabilities with acoustic transmission of readings to the surface. The stack can be connected to a BOP or a flex joint, or it can be on top of a wellhead. The subsea capping stack is deployable on either drill pipe or wire, and deployment is aided by a rig or crane/winch wire with quick changeout of the running tool interface.

The technical specifications of the two subsea capping stacks are provided in Table 3.11 and Table 3.12.

Table 3.11: WellCONTAINED Aberdeen Subsea Capping Stack Technical Specifications

WellCONTAINED Aberdeen Subsea Capping Stack		
Parameter	**Value**	
Manufacturer	Wild Well Control	
Primary Bore	18-3/4 in. with 3 rams	
Diverter Outlets	(4) 3-1/16 in. with dual gate valves	
Pressure Rating	15,000 psi	
Temp. Rating	250°F	
Water Depth	10,000 ft.	
Soft Shut-in Capability	Yes – with 2 chokes	
Flow Back Capability	Yes – 100,000 bpd	
Chemical Injection	Yes – Hydrate remediation/dispersant	
Controls	ROV with subsea HPU	
Installation Method	Drill pipe or Wire	
Weight/Air Freight	96 tons/Yes	
Dimensions (LxWxH)	18.4 x 12.9 x 24 ft.	
Storage Location	Aberdeen, Scotland	
Serving Region	Worldwide	

Table 3.12: WellCONTAINED Singapore Subsea Capping Stack Technical Specifications

WellCONTAINED Singapore Subsea Capping Stack	
Parameter	**Value**
Manufacturer	Trendsetter Engineering
Primary Bore	18-3/4 in. with dual rams
Diverter Outlets	(4) 5-1/8 in. with dual gate valves
Pressure Rating	15,000 psi
Temp. Rating	250°F
Water Depth	10,000 ft.
Soft Shut-in Capability	Yes – with 4 chokes
Flow Back Capability	Yes – 200,000 bpd
Chemical Injection	Yes – Hydrate remediation/dispersant
Controls	ROV with subsea accumulator module
Installation Method	Drill pipe or Wire
Weight/Air Freight	96 tons/Yes
Dimensions (LxWxH)	16 x 14 x 20.5 ft.
Storage Location	Singapore
Serving Region	Worldwide

3.2.5.3 Storage Locations

The subsea capping stacks and other ancillary equipment are located in Aberdeen and Singapore. Figure 3.11 shows the WellCONTAINED subsea capping stack global storage locations.

Figure 3.11: WellCONTAINED Subsea Capping Stack Storage Locations

3.2.6 Shell

Royal Dutch Shell plc, commonly known as Shell, is an Anglo-Dutch multinational oil and gas company headquartered in the Netherlands and incorporated in the United Kingdom. Shell owns subsea capping stack systems to cover their global portfolio of subsea wells. They are used primarily to back up Shell operations in addition to the consortium systems [20].

Shell owns three subsea capping stacks. One is stored and maintained in Aberdeen, Scotland, and it is readily available for emergency deployment via air freight to Shell operations worldwide. After it is on location, it can be deployed via wire or drill pipe from a rig or a service vessel. The capping system is designed with a 10,000 psi working pressure for use in water depths up to 10,000 ft.

A second Shell-owned capping system, which is stored and maintained in Singapore, has a similar design and a 15,000 psi working pressure for use on wells that require this higher pressure rating. It also provides flexibility for global deployment.

Shell has a well capping system in Alaska that is stored for deployment in the Arctic and is ready to respond to potential subsea well control events. This system is designed to deal with Arctic conditions[15], including the logistics of a remote location.

[15] The Arctic subsea capping stacks are designed such that they can be placed in mudline cellars or glory holes. A mudline cellar allows for the subsea equipment to be installed below the seafloor at depths greater than the anticipated ice gouge depth. The Arctic subsea capping stacks are designed to withstand the low temperatures experienced in the Arctic environment, and materials are selected accordingly.

These Shell-owned capping systems complement the MWCC and OSRL systems that are available to Shell, and they add to global capability in the event that primary and secondary well control measures fail to control a well.

Currently, Shell is developing a 20,000 psi-rated cap and a 400°F-rated cap to meet future well needs.

Table 3.13, Table 3.14, and Table 3.15 provide the technical specifications of the Aberdeen, Singapore, and Arctic subsea capping stacks, respectively.

Table 3.13: Shell Aberdeen Subsea Capping Stack Technical Specifications

Shell Aberdeen Subsea Capping Stack	
Parameter	**Value**
Manufacturer	Cameron Ltd.
Primary Bore	13-5/8 in. with dual rams
Diverter Outlets	—
Pressure Rating	10,000 psi
Temp. Rating	—
Water Depth	10,000 ft.
Soft Shut-in Capability	—
Flow Back Capability	—
Chemical Injection	—
Controls	ROV with Subsea Accumulator Module
Installation Method	Drill Pipe or Wire
Weight/Air Freight	30 metric tons/Yes
Dimensions (LxWxH)	—
Storage Location	Aberdeen, Scotland
Serving Region	Worldwide

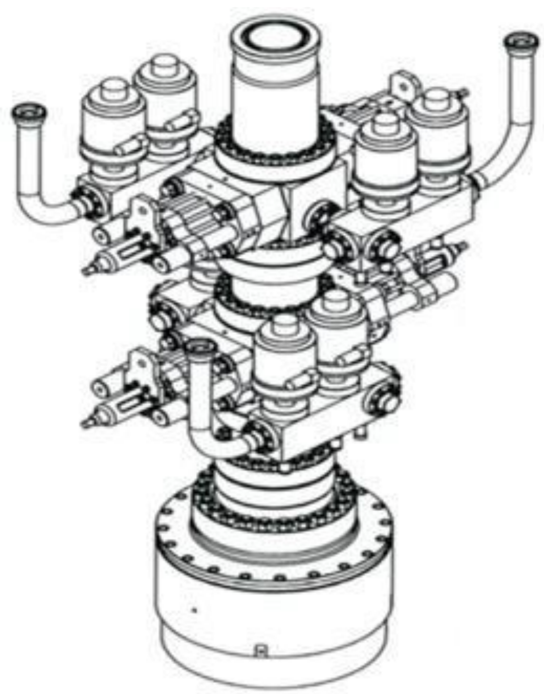


Table 3.14: Shell Singapore Subsea Capping Stack Technical Specifications

Shell Singapore Subsea Capping Stack	
Parameter	**Value**
Manufacturer	Cameron Ltd.
Primary Bore	13-5/8 in. with dual rams
Diverter Outlets	(4) 3-1/16 in. with dual gate valves
Pressure Rating	15,000 psi
Temp. Rating	250°F
Water Depth	10,000 ft.
Soft Shut-in Capability	Yes – with 2 chokes
Flow Back Capability	Yes
Chemical Injection	Yes – Hydrate remediation/dispersant
Controls	ROV with Subsea Accumulator Module
Installation Method	Drill Pipe or Wire
Weight/Air Freight	30 metric tons/Yes
Dimensions (LxWxH)	—
Storage Location	Singapore
Serving Region	Worldwide

Table 3.15: Shell Arctic Subsea Capping Stack Technical Specifications

Shell Arctic Subsea Capping Stack	
Parameter	**Value**
Manufacturer	Trendsetter Engineering
Primary Bore	18-3/4 in. with dual rams
Diverter Outlets	(2) 5-1/8 in. with dual gate valves
Pressure Rating	10,000 psi
Temp. Rating	250°F
Water Depth	10,000 ft.
Soft Shut-in Capability	No
Flow Back Capability	Yes – 50,000 bpd
Chemical Injection	Yes – Hydrate remediation/dispersant
Controls	ROV
Installation Method	Wire
Weight/Air Freight	96 tons/No
Dimensions (LxWxH)	16 x 16.5 x 29.5 ft.
Storage Location	Stored in Denmark, during drilling operation placed on a boat close to the well
Serving Region	Arctic

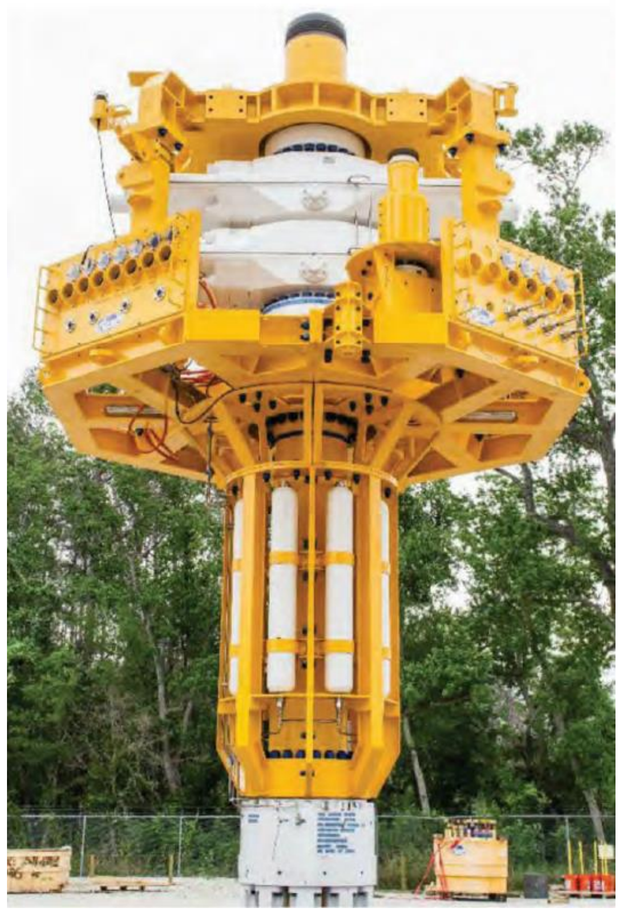


Figure 3.12 shows the global storage locations of the Shell-owned subsea capping stacks.

Figure 3.12: Shell Subsea Capping Stack Storage Locations

3.2.7 BP

According to the information available from the industry survey and literature review, BP owns two subsea capping stacks, with one placed in Angola and the other in Houston.

The Angola subsea capping stack is cap only and serves only the West Africa region. The Houston subsea capping stack is a global subsea capping stack and can be transported by air. Table 3.16 provides the technical specifications of the BP Angola subsea capping stack.

Table 3.16: BP Angola Subsea Capping Stack Technical Specifications

BP Angola Subsea Capping Stack		
Parameter	**Value**	
Manufacturer	Cameron Ltd.	
Primary Bore	No rams, hydraulic fail-safe close (FSC) valves	
Diverter Outlets	zero	
Pressure Rating	10,000 psi	
Temp. Rating	—	
Water Depth	10,000 ft.	
Soft Shut-in Capability	No – zero chokes	
Flow Back Capability	No	
Chemical Injection	Yes – Hydrate inhibition/dispersant	
Controls	ROV	
Installation Method	Drill Pipe or Wire	
Weight/Air Freight	56 metric tons/No	
Dimensions (LxWxH)	—	
Storage Location	Angola	
Serving Region	West Africa	

The Houston subsea capping stack consists of two sections:

- The lower module is a horizontal subsea production tree with integrated pressure and temperature sensors.
- The upper stack consists of a hydraulic connector and two gate valves.

Because of logistical constraints, the stack was designed as two separate sections, as it has to be air-transportable for rapid deployment to be used. BP has selected the Antonov AN-124, a huge Russian transport aircraft, to transport the subsea capping stack system.

Although the AN-124 is the only aircraft that can handle the massive BP subsea capping stack load, multiple Boeing 747s can be used to assist with the transportation process in the case of an accident. The system includes tooling for the subsea capping stack and other support equipment that may be needed to contain a well blowout [21].

The equipment is continuously being developed; therefore, new parts are sometimes added, while others are changed or upgraded. The toolkit includes more than 250 pieces of equipment, including:

- A subsea dispersant package.
- A range of ROV tools with saws, torque tools, and other debris removal tools, pipe grapples, and pipe shears.
- A subsea HPU with a launch and recovery system that provides hydraulic power for the subsea capping stack operations.

A subsea hydraulic accumulator system is also included to provide emergency hydraulic power to the BOP stack. A range of cap adapters has been built to fit the different risers on BOP rigs around the world.

The subsea capping stack was designed to fit on top of the BOP stack after the LMRP is removed. However, if for some reason the LMRP cannot be removed, the subsea capping stack is capable of mating with the flex joint riser adapter, which is where the bottom riser joint hooks up to the LMRP. Table 3.17 provides the technical specifications of the BP Houston subsea capping stack, and Figure 3.13 shows BP subsea capping stack locations.

Table 3.17: BP Houston Subsea Capping Stack Technical Specifications

BP Houston Subsea Capping Stack	
Parameter	**Value**
Manufacturer	Cameron
Primary Bore	—
Diverter Outlets	5-1/8 in. with dual gate valves
Pressure Rating	15,000 psi
Temp. Rating	—
Water Depth	10,000 ft.
Soft Shut-in Capability	—
Flow Back Capability	Yes – 100,000 bpd
Chemical Injection	Yes – Hydrate inhibition
Controls	ROV
Installation Method	Drill pipe or Wire
Weight/Air Freight	99 tons/Yes
Dimensions (LxWxH)	—
Storage Location	Houston, U.S.
Serving Region	Worldwide

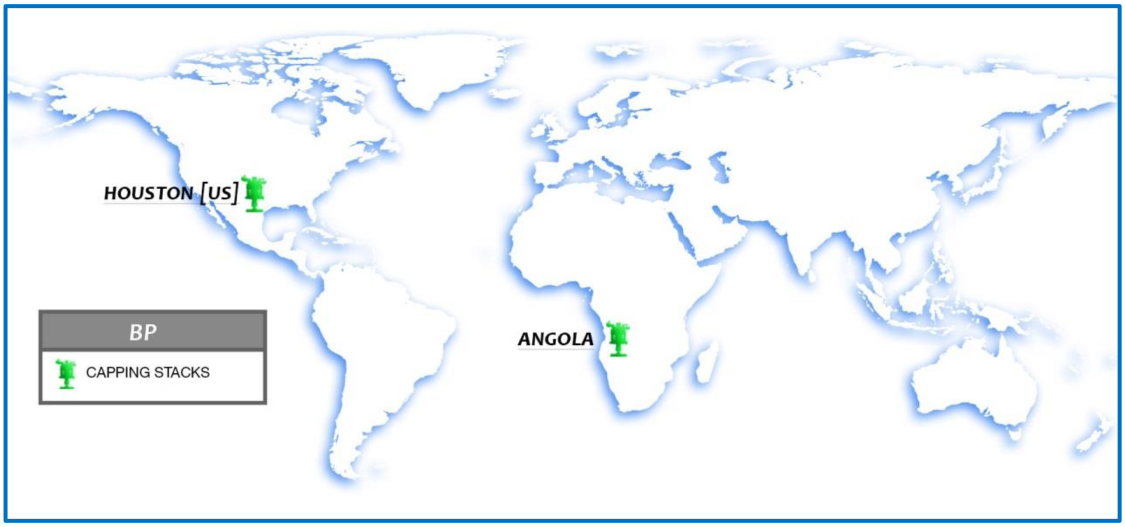


Figure 3.13: BP Subsea Capping Stack Storage Locations

4.0 Subsea Capping Stacks Gap Analysis

Offshore drilling is currently ongoing at various regions around the world. To ensure the safety of personnel and prevent marine pollution, well containment equipment must be accessible during operations for all regions.

Figure 4.1 shows the regions where offshore drilling is currently ongoing or planned. The information in Figure 4.1 is not conclusive and is provided for information purposes only.

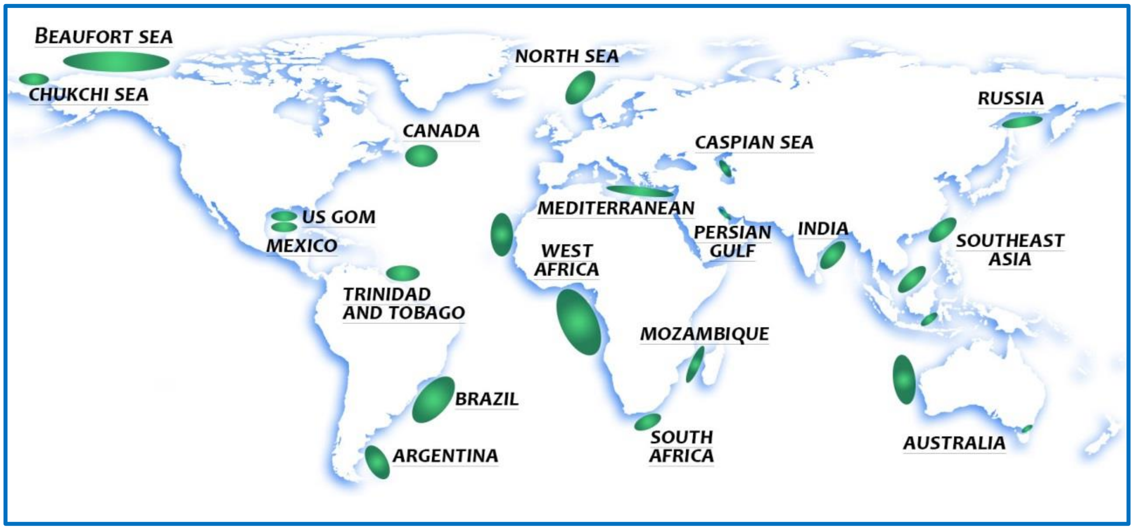


Figure 4.1: Global Offshore Drilling Locations

A list of available local and global subsea capping stacks is provided in Table 4.1. The table lists the subsea capping stack Owner, its storage location, and the region(s) it serves. It is possible that there can be additional subsea capping stacks (not listed in Table 4.1) that are owned by some of the major oil companies and are placed at different locations around the world.

Table 4.1: Available Subsea Capping Stacks with Storage Locations and Serving Regions

Owner	Subsea capping stack	Storage Location	Serving Region
MWCC	Subsea Containment Assembly (SCA)	Ingleside, Texas	GOM
	15k psi subsea capping stack		
	10 k psi subsea capping stack		
HWCG	15k psi subsea capping stack	Houston, Texas	GOM
	10k psi subsea capping stack	Ingleside, Texas	
OSPRAG	OSPRAG subsea capping stack	Aberdeen, Scotland	UKCS
OSRL	15k psi subsea capping stack	Norway	Worldwide (except U.S. waters)
	15k psi subsea capping stack	Brazil	
	10k psi subsea capping stack	South Africa	
	10k psi subsea capping stack	Singapore	
WellCONTAINED	Aberdeen subsea capping stack	Aberdeen, Scotland	Worldwide
	Singapore subsea capping stack	Singapore	
Shell	Aberdeen subsea capping stack	Aberdeen, Scotland	Worldwide (Shell Operations Only)
	Singapore subsea capping stack	Singapore	
	Arctic subsea capping stack	Alaska	Arctic locations (Shell Operations Only)
BP	Angola subsea capping stack	Angola	West Africa (BP Operations Only)
	Houston subsea capping stack	Houston, Texas	For GOM but with global mission (BP Operations Only)

For the GOM, there are five subsea capping stacks that are locally available and ready to respond to a well control incident. In addition, two WellCONTAINED subsea capping stacks, which are located outside of the U.S., can be used if needed. It is mandatory for Operators drilling in the GOM to demonstrate access to a subsea capping stack and the necessary expertise to control a blowout well. Currently, Operators rely on either of the MWCC or HWCG subsea capping stacks to perform drilling activity in the GOM. Figure 4.2 shows the subsea capping stacks that can serve the GOM region only.

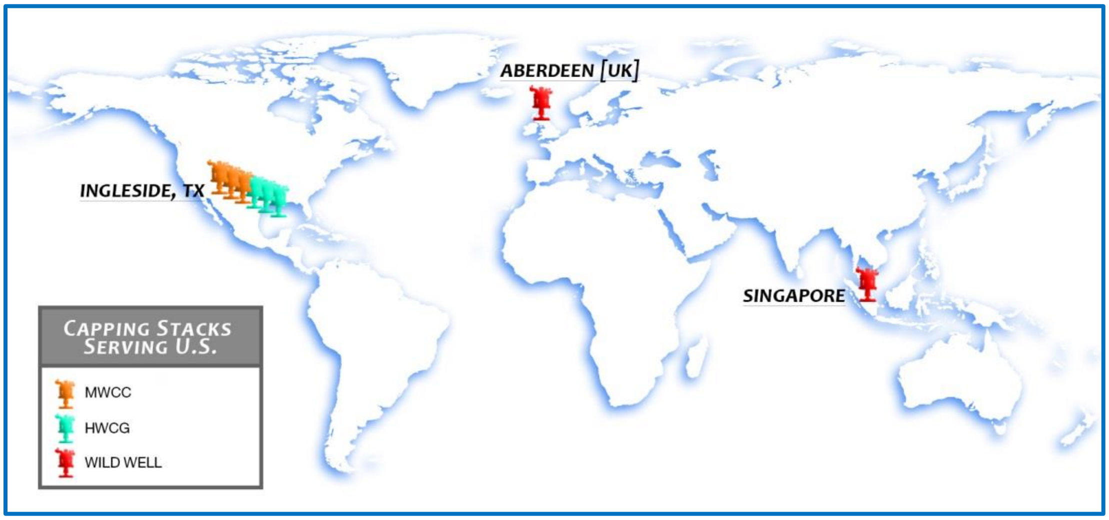


Figure 4.2: Subsea Capping Stacks that Serve the U.S. OCS

For the UKCS, there is one OSPRAG subsea capping stack that is stored in Aberdeen and is local to the region. WellCONTAINED has a subsea capping stack in Aberdeen that can serve globally. SWRP's four subsea capping stacks can also be accessed, if needed, to serve the UKCS. Overall, this region has access to seven subsea capping stacks (one OSPRAG, two WellCONTAINED, and four SWRP).

No countries or regions outside of the U.S. and the U.K. have industry-led consortiums. OSRL and WellCONTAINED subsea capping stacks are currently used by oil companies outside the U.S. and the U.K. to respond to well control incidents. SWRP subsea capping stacks serve all regions except U.S. waters, while WellCONTAINED subsea capping stacks do not have that limitation. Figure 4.3 shows the storage locations of the OSRL and WellCONTAINED subsea capping stacks.

Because of global availability, it can be said that there is a subsea capping stack for all regions of the world. The caveat to this statement is that most of the companies do not have access to a local subsea capping stack, and they depend on the consortiums that own global capping solutions.

Global capping solutions have longer response times associated with transport from their storage locations to the incident sites. In addition to air transport, subsea capping stacks must be disassembled and reassembled, which adds to the response time. Long response times have a significant impact on the recovery efforts because the longer response times allow more hydrocarbons to release to the environment. Having subsea capping stacks available in each country to quickly respond to a well control incident will be beneficial.

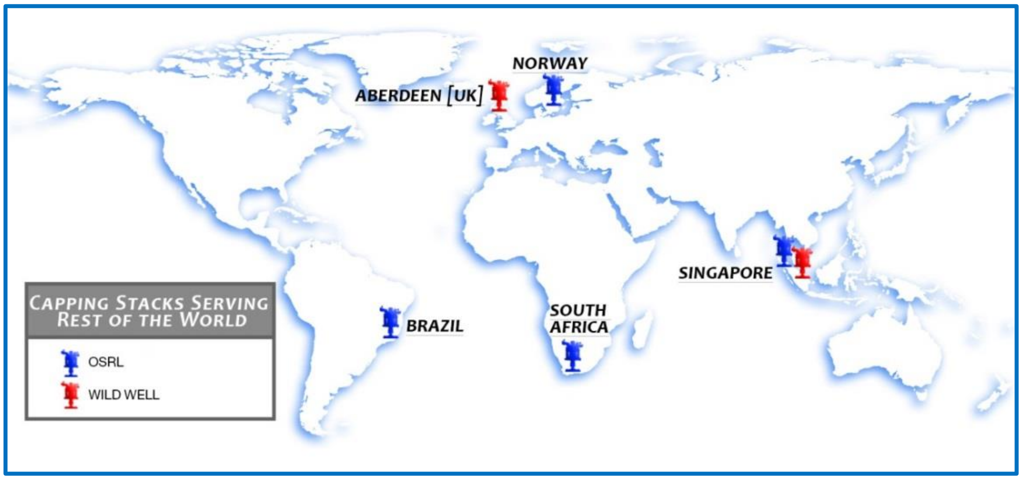


Figure 4.3: Subsea Capping Stacks that Serve the World (except U.S. OCS)

5.0 Specifications, Standards, and Recommended Practices Applicable to Subsea Capping Stacks

5.1 Introduction

This section presents a review of proposed regulations, recommended practices (RPs), specifications, and standards to evaluate the existing procedures for the design, manufacture, and use of subsea capping stacks.

A subsea capping stack, which is a relatively new technology, is rapidly evolving in the oil and gas industry. Currently, API RP 17W [3] is the only guidance available in the industry. Because subsea capping stacks are built using components that are already available and being used for subsea equipment (for example, BOPs and christmas trees), the standards and guidelines that already exist for such equipment are used to design subsea capping stacks.

5.2 API Specifications Relevant to Subsea Capping Stacks

5.2.1 API 16D – Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment

API Specification 16D [22] provides the design, manufacture, and installation requirements for BOP stacks. It contains specifications for equipment that is common to discrete hydraulic and EH/Multiplex (MUX) control systems for subsea BOP stacks. This specification includes the accumulator and pump system requirements necessary to meet the response times and redundancy needs of different equipment. The specification also includes requirements for EDS systems and backup control systems.

According to API 16D, subsea BOP control systems must meet the following requirements:

- Closing response times are not to exceed 45 seconds for each ram BOP.
- Closing response times for each annular BOP are not to exceed 60 seconds.
- Operating responses for each choke and kill valve (either open or closed) are not to exceed the minimum observed ram close response time.
- The response time to unlatch the riser (LMRP) connector is not to exceed 45 seconds.

API 16D also provides a list of allowable functions for the optional EDS and the backup control systems. ROV intervention is one of the backup control systems that is used to shut in the well during an emergency scenario.

The ROV must be capable of unlocking the riser and wellhead connectors, along with the following optional functions:

- Close blind/shear rams
- Close pipe rams
- Open choke or kill valves
- Close choke or kill valves
- Accumulator discharge
- Ram locking mechanisms

For a multi-function system, the subsea capping stack Owner may mount an operating panel on a BOP stack in an accessible location with a clear label for identification using ROV cameras. API Specification 16D also provides the maintenance procedure, periodic inspection requirements, and relevant documentation for BOP stacks.

5.2.2 API 6A – Specification for Wellhead and Christmas Tree Equipment/ISO 10423

API Specification 6A [23] provides requirements and recommendations for the functional interchangeability, design, materials, testing, inspection, welding, handling, storage, and shipment of wellhead and christmas tree equipment. This specification applies to connectors, fittings, casing and tubing hangers, valves and chokes, and wellhead equipment.

All connectors, valves, chokes, and fittings in the subsea capping stack must conform to this specification.

5.2.3 API 16A – Specification for Drill-through Equipment/ISO 13533

API Specification 16A [24] specifies requirements for performance, design, materials, testing, inspection, and welding of drill-through equipment used for drilling. The specification also defines the service conditions in terms of the pressure, temperature, and wellbore fluids for which the equipment is designed.

API Specification16A establishes requirements for the following specific equipment:

- Ram and annular BOPs
- Ram blocks, packers, and top seals
- Annular packing units
- Drilling spools
- Adapters
- Loose connections
- Clamps

5.2.4 API 17D – Design and Operation of Subsea Production Systems – Subsea Wellhead and Tree Equipment

API Specification 17D [25] provides specifications for subsea wellheads and vertical/horizontal subsea trees. The specification also provides the associated tooling necessary to handle, test, and install the equipment.

API Specification 17D includes specifications for the following equipment:

- Subsea trees
- Subsea wellheads
- Mud line suspension systems
- Drill-through mud line suspension systems
- Tubing hanger systems
- Miscellaneous equipment (for example, flanged end and outlet connections, clamp hub-type connections, other end connections, studs, nuts, ring joint gaskets)

5.2.5 API 6AV1 – Specification for Validation of Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service

API Specification 6AV1 [26] establishes requirements to verify:

- Verify standard service Surface Safety Valve (SSV) and Underwater Safety Valve (USV) design.
- Verify the basic SSV/USV actuator design.
- Demonstrate the verification testing covered by this specification, which is required to qualify specific valve bore sealing mechanisms manufactured under API Specification 6A for sandy service safety valves.

5.3 API Standard 53 – Blowout Prevention Equipment Systems for Drilling Wells

API Standard 53 [27] provides the requirements for installing and testing BOP equipment systems on land and marine drilling rigs. This standard also includes the minimum requirements for surface and subsea BOP stack classifications, pressure designations, stack arrangements, and hydraulic control systems.

The main bore vertical closure device in the subsea capping stack must meet the closing times specified in API Standard 53.

5.4 API Recommended Practices Relevant to Subsea Capping Stacks

5.4.1 API 17W – Recommended Practice for Subsea Capping Stacks

API RP 17W [3] provides recommended practices for the design, manufacture, and use of subsea capping stacks and provides guidelines for the preservation, testing, inspection, maintenance, and storage of subsea capping stacks.

5.4.1.1 Section 4

Section 4 of API RP 17W states that, at a minimum, the subsea capping stack:

- Can monitor pressure below each vertical bore mechanical closure device.
- Allows injection of the hydrate inhibitors and chemicals into the main vertical bore below the vertical outlets.
- Contains one or more outlets for diverting flow and/or pumping kill fluid into the main vertical bore.

In addition, the subsea capping stack must:

- Inject kill fluids into the wellbore.
- Facilitate monitoring of critical wellbore parameters (for example, pressure and temperature).
- Contain standardized interfaces on all inlets and outlets.

Section 4 also details the interface descriptions, design, and functional requirements (for example, service conditions, component design, flow isolation barriers).

For subsea capping stacks built with a global perspective, all materials that come in contact with the well fluids must meet the requirements of NACE MR0175 for sour service. NACE MR0175 was developed for the prevention of sulfide stress cracking caused by hydrogen sulfide (H_2S) in the oil and gas production systems (refer to Section 4.4.7.4 Sour Service of API RP 17W).

5.4.1.2 Section 5

Section 5 of API RP 17W provides a list of steps for using a subsea capping stack.

The list includes:

- Initial actions.
- Equipment notification and callout.
- Well condition assessment.
- Subsea capping stack deployment.

5.4.1.3 Section 6

Section 6 of API RP 17W provides details of the various tests (such as function tests, pressure tests), maintenance schedules, inspection plans, and preservation and the protection of elastomeric materials, fluids, and spare parts from environmental effects.

API RP 17W refers to other standards and specifications (such as API Standard 53 [27], API Specification 6A [23], API Specification17D [25], API Specification16A [24], and API RP 17H [6]) for the design and use of various components of a subsea capping stack).

5.4.2 API 17H – Recommended Practice for Remotely Operated Vehicle (ROV) Interfaces on Subsea Production Systems

API RP 17H [6] provides design recommendations for subsea intervention systems and ROV interfaces. The different interfaces provided are rotary (for example, low-torque) interface, rotary docking, linear (such as push) interfaces, different types of hot stab hydraulic connections, and component change-out interfaces. In addition, API RP 17H provides recommendations for typical dimensions that can be assumed for access validation, minimum elevation of ROV interface above seabed, and ROV stabilization methods during the intervention tasks. This recommended practice also provides the features and dimensions of different types of hot stabs and receptacles that can be used to override existing systems and complement systems, including lower riser packages with locking and unlocking functions, hydraulically activating valves and tools, and more.

The subsea capping stack hydraulic functions are fitted with API RP 17H ROV hot stab receptacles. The rams used as vertical main bore closure devices must close in less than 45 seconds to meet the API Standard 53 closing time requirements and must be fitted with API RP 17H Type C (such as high flow) hot stab devices with external locking devices.

5.4.3 API 17G – Recommended Practice for Completion/Workover Risers

API RP 17G [28] provides requirements and recommendations for the design, analysis, materials, fabrication, testing, and operation of subsea completion/workover riser systems run from a floating vessel.

API RP 17G includes specifications for the following equipment:

- Riser joints
- Connectors
- Workover control systems
- Surface flow trees

- Surface tree tension frames
- Lower workover riser packages
- Lubricator valves
- Retainer valves
- Subsea test trees
- Shear subs
- Tubing hanger orientation systems
- Swivels, annulus circulation hoses, riser spiders, umbilical clamps, handling and test tools, and tree cap running tools

6.0 U.S and Global Regulations Available for Subsea Capping Stacks

6.1 Introduction

This section assesses the capping solutions and regulations that are in place for countries which are members of the International Regulators Forum (IRF). A review of the active and proposed U.S. regulations related to well control and containment equipment is included.

Currently, there are no specific Code of Federal Regulations (CFRs) in place in the U.S. for subsea capping stacks. Notice to Lessees and Operators (NTL) number 2010-N10 [29] states that Operators must provide adequate information demonstrating that they can access and deploy a containment system during a blowout or other loss of well control.

6.2 International Regulators Capping Solutions

6.2.1 Australian Capping Solution

Currently, Australia does not have regulations that are specific to subsea capping stacks.

Australia has no local subsea capping stack and depends on the four OSRL subsea capping stacks. The closest and most preferred subsea capping stack is the one in Singapore. Some of the Australian companies are members of WellCONTAINED and use the WellCONTAINED subsea capping stacks.

To perform a drilling activity, the National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA) must approve the Well Operations Management Plan. The Plan must satisfy the regulator requirements that the plan is appropriate for the nature and scale of the well activity and that it shows the risks identified as they relate to well activities. These identified risks are to be managed by sound engineering principles, standards, specifications, and good oilfield practice.

A consortium of 12 oil and gas companies operating in Australian waters (Apache, BP, BHP Billiton Petroleum, Chevron, ConocoPhillips, ENI, ExxonMobil, INPEX, PTT Exploration and Production [PTTEP], Santos, Shell, and Woodside) have committed to the development of an Australian component of the Well Capping and Containment Solution, called the Subsea First Response Toolkit (SFRT).

The Australian Marine Oil Spill Centre (AMOSC) owns the SFRT on behalf of the industry, with Oceaneering providing the equipment and expertise for mobilization and deployment. The SFRT is designed to fit on any work class ROV and can also enable the application of subsea dispersant where there is a need to make the surface safe for work.

The SFRT, which is located in Australia, contains all specialized equipment necessary to enable the wellhead and the surrounding area, including the seabed, to be cleaned up and made safe for the installation of a capping device. All Australian offshore petroleum Operators will have access to the toolkit on an affordable basis.

Tasks performed by the SFRT include:

- Speciality ROV tasks
- Intervention on existing BOPs and operate them hydraulically
- Surveys, mapping, and video recordings
- Setting of sonar arrays for equipment guidance during deployment
- Application of subsea dispersant at the well
- Clearing of debris from the wellhead area

The time to mobilize a global subsea capping stack is anticipated to be approximately 9 to 11 days. However, a subsea capping stack cannot be deployed on the wellhead/BOP of the incident site until the site has been cleared and made safer. The time to prepare the well for a subsea capping stack is estimated to be 14 to 21 days. Therefore, by the time the incident site is cleared, the global subsea capping stack will reach the incident well location and be ready for deployment.

NOPSEMA Environmental Guidance Note, N-04700-GN0940, Rev. 2, July 2012 [30] provides the roles and responsibilities of the petroleum Operator and NOPSEMA during a well control incident.

6.2.2 Canadian Capping Technology

The Canadian Environmental Assessment Agency is considering the following potential conditions for recommendation to the Minister of Environment for inclusion in a Decision Statement under the Canadian Environmental Assessment Act, 2012. [31]:

- The Operator must present all reasonable measures to prevent accidents and malfunctions that can result in adverse environmental effects and must implement appropriate emergency response procedures and contingency plans to the satisfaction of the Canada-Nova Scotia Offshore Petroleum Board (CNSOPB).
- The Operator must prepare an Oil Spill Response Plan and a Well Containment Plan in accordance with CNSOPB requirements and submit the plan for approval at least 90 days before drilling.

- The Oil Spill Response Plan must include:
  - Procedures to respond to an oil spill (for example, oil spill containment, oil recovery).
  - Measures for wildlife response, protection, and rehabilitation (for example, collect and clean marine mammals, birds, and sea turtles) and for shoreline protection and clean-up, which are to be developed in consultation with CNSOPB.
  - Procedures to notify CNSOPB and other relevant regulatory agencies of the occurrence of any oil spill as soon as possible.
- The Operator must conduct an exercise of the oil spill response before beginning project activities.
- The Well Containment Plan must include:
  - A Relief Well Contingency Plan.
  - A Well Capping Plan describing the plan to mobilize and deploy a subsea capping stack, if required.
- In the event of an incident, the Operator must implement the Oil Spill Response Plan and the Well Containment Plan.

In an effort to develop a capping solution for Canada, Waterford Energy Services Inc. (WESI) formed a joint venture company with Trendsetter Engineering to serve the Canadian offshore market in the areas of subsea solutions, drilling, completions, and well control.

The joint venture company provides the Canadian offshore market with a subsea capping stack and containment solution, subsea trees, manifolds, and related equipment. They have developed the First Response Well Containment System for Canada, which uses equipment and technology located in Newfoundland and Labrador to provide immediate and local response to an offshore incident.

Currently, no local subsea capping stack is available in Canada.

6.2.3 Norway Capping Solution

In Norway, the Petroleum Safety Authority (PSA) has the regulatory responsibility for safety, emergency preparedness, and the working environment for all offshore and onshore petroleum-related activities.

Norway does not have a local consortium that owns subsea capping stacks to serve the Norwegian region. They depend on the global capping solutions from OSRL and WellCONTAINED. One of the OSRL subsea capping stacks is stored in Norway. In June 2013, Norway updated the NORSOK Standard D010 – Well Integrity in Drilling and Well

Operations document [32]. NORSOK Standard D-010 includes the plans for the capping and containment of a blowing subsea well and the plans for drilling a relief well.

6.2.4 U.K. Capping Solution

The U.K. has no specific regulations concerning subsea capping stacks. The U.K. has access to the local OSPRAG subsea capping stack, which is stored in Aberdeen, Scotland. In addition, it also has access to the OSRL and WellCONTAINED global subsea capping stacks.

6.2.5 Brazil Capping Solution

No information is available on subsea capping stack regulatory requirements for Brazil.

Similar to Norway, Brazil does not have a local consortium that owns subsea capping stacks. Brazil depends on the global capping solutions from OSRL and WellCONTAINED. One of the OSRL subsea capping stacks is stored in Angra dos Reis, Brazil.

6.2.6 New Zealand Capping Solution

New Zealand operates within a goal setting regime where there is rarely any specific legislation on particular technologies such as subsea capping stacks.

Operators must submit a Discharge Management Plan to Maritime New Zealand (MNZ) before starting drilling operations. The Well Control Contingency Plan (WCCP) section of the Discharge Management Plan has a contingency plan that the Operator must follow in a worst-case scenario. MNZ approves the Discharge Management Plan only if the Operator has procedures in place that will prevent or mitigate the environmental impacts from an accidental loss.

If a significant oil spill occurs, MNZ's Marine Pollution Response Service is New Zealand's lead national oil spill response agency. It is responsible for maintaining a nationwide capability to respond to marine oil spills through comprehensive national and international agreements.

6.2.7 Denmark, Mexico, and the Netherlands Capping Solution

There is no information available on regulatory requirements for capping solutions in Denmark, Mexico, or the Netherlands.

Denmark, Mexico, and the Netherlands depend on the global OSRL and WellCONTAINED subsea capping stacks. There are no local subsea capping stacks dedicated to this region. Pemex is working with BP to provide a subsea capping stack solution for Mexico.

Currently, most of the oil and gas companies are justifying their contingency plans with the regulators by using global subsea capping stack systems on a case-by-case basis. This has advantages in terms of cost and standardization of tools and equipment, but the details of mobilization, staging, assembly, testing, and installation vary from one location to another.

6.3 Current U.S. Regulations – 30 CFR 250

The BSEE website (www.bsee.gov) directs users to the Electronic Code of Federal Regulations (E-CFR) webpage (www.ecfr.gov), where the current regulations are placed and updated periodically [33].

On the E-CFR webpage, the regulations for Blowout Preventer (BOP) systems and well control are provided under Title 30 → Chapter II → Subchapter B → Part 250 (referred to as 30 CFR 250). Part 250, which is named Oil and Gas and Sulphur Operations in the Outer Continental Shelf, provides information on the plans and includes requirements for oil and gas drilling, well control, well completion, workover, production, and decommissioning operations. A complete list of subparts with CFR numbering and titles is provided in Table 6.1.

Table 6.1: The BSEE 30 CFR 250 Subparts List

Subpart	CFR Numbering	Title of Subpart
A	§250.101	General
B	§250.200	Plans and Information
C	§250.300	Pollution Prevention and Control
D	§250.400	Oil and Gas Drilling Operations
E	§250.500	Oil and Gas Well-Completion Operations
F	§250.600	Oil and Gas Well-Workover Operations
H	§250.800	Oil and Gas Production Safety Systems
I	§250.900	Platforms and Structures
J	§250.1000	Pipelines and Pipeline Rights-of-Way
K	§250.1150	Oil and Gas Production Requirements
L	§250.1200	Oil and Gas Production Measurement, Surface Commingling, and Security
M	§250.1300	Unitization
N	§250.1400	Outer Continental Shelf Civil Penalties
O	§250.1500	Well Control and Production Safety Training
P	§250.1600	Sulphur Operations
Q	§250.1700	Decommissioning Activities
S	§250.1900	Safety and Environmental Management Systems (SEMS)

Subpart D provides the requirements for oil and gas drilling operations. Sections 250.440 to §250.451 (Blowout Preventer [BOP] System Requirements) provide the minimum requirements for a surface BOP system, subsea BOP system, and associated equipment. The BOP maintenance, inspection, testing, and recordkeeping requirements are provided in this section of the regulations.

According to §250.442, anyone who drills with a subsea BOP system must:

- Have at least four remote-controlled, hydraulically operated BOPs (at least one annular preventer, two pipe rams, and one blind shear ram).
- Have an operable dual-pod control system to ensure proper and independent operation of the BOP system.
- Have an accumulator system to provide fast closure of all BOP components and to operate all critical functions in case of a loss of the power fluid connection to the surface. The closing time must meet the API RP 53 response times.

- Have a subsea BOP stack that is equipped with ROV intervention capability. At a minimum, the ROV must be capable of closing one set of pipe rams, closing one set of blind shear rams, and unlatching the LMRP.
- Provide Autoshear and Deadman systems for dynamically positioned rigs.
- Clearly label all control panels for the subsea BOP system.
- Establish the minimum requirements for personnel authorized to operate critical BOP equipment.

§250.443 states that all BOP systems must include the following associated systems and related equipment:

- An automatic backup to the primary accumulator charging system. The power source must be independent from the primary accumulator power source. The independent power source must have sufficient capability to close and hold closed all BOP components.
- At least two BOP control stations. One station must be on the drilling floor. The other station must be located in a location that is readily accessible from the drilling floor.
- Side outlets on the BOP stack for separate choke and kill lines. If the stack does not have side outlets, a drill spool with side outlets must be installed.
- Both choke and kill lines must have two full-opening valves and must be remote-controlled. The choke line must be installed above the bottom ram. The kill line may be installed below the bottom ram.

Section 250.446 provides the following BOP maintenance and inspection requirements:

- The BOP maintenance and inspection must ensure that the equipment functions properly. The BOP maintenance and inspection must exceed the provisions described in API RP 53.
- The subsea BOP and marine riser must be visually inspected at least once every three days if weather and sea conditions permit.

Sections 250.447, 250.448, and 250.449 provide the following BOP testing requirements:

- Pressure testing must be performed on the BOP system (this includes the choke manifold, kelly valves, inside BOP, and drill string safety valve).
- A low pressure and high pressure test must be conducted for each BOP component. The low pressure test must be conducted before the high pressure test. Each individual pressure test must hold the required pressure for 5 minutes.

- A stump test of the subsea BOP system must be performed before installation.
- Annular and ram BOPs must be function tested every seven days between pressure tests.

Section 250.450 provides the recordkeeping requirements for BOP tests.

Similar to Subpart D, Subparts E, F, and Q also provide the requirements for BOP systems and associated equipment. The current regulations repeat similar BOP requirements in multiple locations (drilling, completion, workover, and decommissioning) throughout 30 CFR 250. The Proposed Rule for well control (refer to Section 6.5.2) consolidates the common BOP requirements into one location.

6.4 Current Notice to Lessees and Operators Related to Well Control

The BSEE issued Notices to Lessees and Operators (NTLs) to clarify, supplement, or provide more details about regulatory requirements under 30 CFR 250 – Oil and Gas and Sulphur Operations in the Outer Continental Shelf. Following the Macondo incident, BSEE issued two NTLs to request additional information from Operators to approve the APD. The two NTLs were NTL 2010-N06 and NTL 2010-N10.

6.4.1 NTL 2010-N06

This NTL provides the information requirements for Exploration Plans (EP)[16] and Development Operations Coordination Documents (DOCD)[17] on the OCS. In accordance with this NTL, the Operator must submit information with the EP, the DOCD, or as a supplement to a previously submitted plan. The information required to be submitted to BSEE as part of the APD includes [34]:

- A scenario of a potential blowout that is expected to have the highest volume of liquid hydrocarbons for the proposed well to be included in the EP or DOCD document.
- Estimated flow rate, total volume, and maximum duration of the potential blowout.
- The potential for a well to bridge over, the likelihood for surface intervention to stop the blowout, the availability of a rig to drill a relief well, and rig package constraints.

[16] *Exploration Plan (EP)* describes all exploration activities planned by an Operator for a specific lease(s), the timing of these activities, information concerning drilling vessels, the location of each well, and an analysis of both offshore and onshore impacts that may occur as a result of the plan's implementation.

[17] A *Development Operations Coordination Document (DOCD)* is a plan that describes development and production activities proposed by an Operator for a lease or a group of leases. The description includes the timing of these activities, information concerning drilling vessels, the location of each proposed well or production platform or other structure, and an analysis of both offshore and onshore impacts that may occur as a result of the plan's implementation.

- The time it would take to contract for a rig, move it onsite, and drill a relief well, including the possibility of drilling a relief well from a neighboring platform or an onshore location.
- Assumptions and calculations that are used to determine the volume of a worst case discharge scenario.
- All assumptions made concerning:
  - The well design, reservoir characteristics, fluid characteristics, and Pressure Volume Temperature (PVT) characteristics.
  - Any analog reservoirs considered in making those assumptions.
  - An explanation of reasons for using those analog reservoirs.
  - The supporting calculations and models used to determine the daily discharge rate possible from the uncontrolled blowout portion of the worst case discharge scenario for both proposed or approved EP or DOCD and the proposed or approved Oil Spill Response Plan (OSRP)[18].
- Proposed measures that would enhance the ability to prevent a blowout, to reduce the likelihood of a blowout, and to conduct effective and early intervention in the event of a blowout, including arrangements for drilling relief wells.

6.4.2 NTL 2010-N10

According to this NTL, Operators using subsea BOPs or surface BOPs on floating facilities must submit sufficient information to BSEE demonstrating that they have access to and can deploy surface and subsea containment resources that are adequate to promptly respond to a blowout or loss of well control [29].

The Bureau of Ocean Energy Management (BOEM) will evaluate whether Operators have provided adequate information in their current OSRPs describing the types and quantities of surface and subsea containment equipment that the Operator can access in the event of a spill or threat of spill, and the deployment time for each. The types of information the BOEM will evaluate include, but are not limited to:

- Subsea containment and capture equipment, including containment domes and subsea capping stacks.
- Subsea utility equipment, including hydraulic power, hydrate control, and dispersant injection equipment.
- Riser systems.
- ROVs.

[18] OSRPs for the offshore oil and gas exploration, production, and transportation (pipeline) industry are regulated in the U.S. by BSEE regulations according to 30 CFR Part 254.

- Capture vessels.
- Support vessels.
- Storage facilities.

6.5 Regulation in Development

6.5.1 Proposed Arctic Drilling Rule

In February 2015, the Department of the Interior (DOI), acting through the BSEE and the BOEM, proposed to revise and add new requirements to regulations for exploratory drilling and related operations on the OCS seaward of the State of Alaska (Alaska OCS). The proposed rule is designed to ensure safe, effective, and responsible exploration of the Arctic OCS (Beaufort Sea and Chukchi Sea Planning Areas) oil and gas resources while protecting the marine, coastal, and human environments; Alaska Natives cultural traditions; and access to subsistence resources [35].

This proposed rule will add to and revise existing regulations in 30 CFR Parts 250, 254, and 550 for Arctic oil and gas activities. The proposed rule focuses on Arctic OCS exploratory drilling activities that use Mobile Offshore Drilling Units (MODUs) and related operations during the Arctic OCS open-water drilling season[19]. This proposed rule addresses a number of important issues and objectives, ensuring that each Operator:

- Designs and conducts exploration programs in a manner suitable for Arctic OCS conditions.
- Develops an Integrated Operations Plan (IOP)[20] that addresses all phases of its proposed Arctic OCS exploration program and submits the IOP to BOEM at least 90 days in advance of filing the Exploration Plan.
- Has access to, and the ability to promptly deploy, Source Control and Containment Equipment (SCCE) while drilling below, or working below, the surface casing.
- Has access to a separate relief rig so that it can timely drill a relief well in the event of a loss of well control under the conditions expected at the site.
- Has the capability to predict, track, report, and respond to ice conditions and adverse weather events.

[19] The Arctic open-water drilling season is typically only 3 – 4 months long and can be much shorter in a given year or be shortened by mid-season ice intrusions. It starts around late June and ends early November.
[20] The purpose of the IOP is to describe, at a strategic or conceptual level, how exploratory drilling activities will be designed, executed, and managed as an integrated endeavor from start to finish.

- Effectively manages and oversees contractors.
- Develops and implements an OSRP that is designed and executed in a suitable manner for the unique Arctic OCS operating environment and has the necessary equipment, training, and personnel for oil spill response on the Arctic OCS.

This proposed rule requires that when the Operator uses a Mobile Offshore Drilling Unit (MODU) to drill below or work below the surface casing, the Operator must have:

- Access to a subsea capping stack that is positioned to arrive at the well within 24 hours after a loss of well control.
- A cap and flow system and a containment dome that are positioned to arrive at the well within 7 days after a loss of well control.

6.5.2 Proposed Well Control Rule

In April 2015, the BSEE proposed new regulations to consolidate equipment and operational requirements that are common to other subparts pertaining to offshore oil and gas drilling, completions, workovers, and decommissioning.

The proposed rule [36]:

- Focuses on the BOP requirements, including incorporation of industry standards and revising existing regulations.
- Includes reforms in areas of well design, well control, casing, cementing, real time well monitoring, and subsea containment.
- Addresses and implements multiple recommendations resulting from various investigations of the Macondo incident
- Incorporates guidance from several NTLs and revised provisions related to drilling, workover, completion, and decommissioning operations to enhance safety and environmental protection.

After the Macondo incident, BSEE issued NTLs for source control and containment requirements during drilling operations. The information in the NTLs was included as part of the new proposed regulations.

In accordance with the proposed Well Control Rule, the Source Control and Containment Requirements will be placed in §250.462 of 30 CFR 250. The proposed rule will include five paragraphs:

1. The first paragraph requires Operators to determine their source control and containment capabilities by evaluating the performance of the well design to determine whether full shut-in can be achieved without reservoir fluids broaching the seafloor. Based on this evaluation, if the well can only be partially shut in, Operators

are required to establish their ability to flow and capture any residual fluids to a surface production and storage system.

2. The second paragraph requires Operators to have access to, and the ability to deploy, the SCCE necessary to regain control of the well.
3. The third paragraph requires the Operator to submit a description of the source control and containment capabilities before BSEE will approve the APD. The submittal to the Regional Supervisor must include:
    a. The source control and containment capabilities for controlling and containing a blowout event at the seafloor
    b. A discussion of the determination required in the first paragraph
    c. Information showing that the Operator has access to, and the ability to deploy, all equipment necessary to regain control of the well
4. The fourth paragraph requires that Operators contact the District Manager and Regional Supervisor for re-evaluation of the source control and containment capabilities if there are any well design changes or if any of the approved SCCE is out of service.
5. The fifth paragraph outlines the maintenance, inspection, and testing requirements of certain identified containment equipment as provided in Table 6.2.

Table 6.2: SCCE Proposed Testing Requirements [36]

Equipment	Requirements	Additional information
(1) Subsea capping stacks	(i) Function test all pressure holding critical components on a quarterly frequency (not to exceed 104 days)	Pressure holding critical components are those components that will experience wellbore pressure during a shut-in after being functioned.
	(ii) Pressure test pressure holding critical components on a bi-annual basis, but no later than 210 days from the last pressure test. All pressure testing must be witnessed by BSEE and a BSEE-approved verification organization,	Pressure holding critical components are those components that will experience wellbore pressure during a shut-in. These components include, but are not limited to, all blind rams, wellhead connectors, and outlet valves.
	(iii) Notify BSEE at least 21 days prior to commencing any pressure testing.	
(2) Production safety systems used for flow and capture operations	(iv) Meet or exceed the requirements set forth in 30 CFR Subpart H, §250.800 through §250.808.	
	(v) Have all equipment unique to containment operations available for inspection at all times.	
(3) Subsea utility equipment	Have all equipment unique to containment operations available for inspection at all times,	Subsea utility equipment includes, but is not limited to, hydraulic power sources, debris removal, hydrate control equipment, and dispersant injection equipment.

7.0 Subsea Capping Stack Design Considerations

7.1 Introduction

The design of a subsea capping stack is affected by factors such as the service environment, preservation environment, component design, transportation, and post-installation functionality requirements.

Design load analysis, fatigue modeling, and flow analysis must be performed to verify:

- The structural integrity of the wellbore to sustain the subsea capping stack loads.
- The ability of the wellbore to sustain shut-in or contained flow pressures.

7.2 Service Conditions

Service conditions refer to the pressure, temperature, material classification, and other operating conditions for which the equipment is designed. High concentrations of solids in well fluids can increase the erosion and are considered in the design of the subsea capping stack.

7.2.1 Pressure Rating

Working pressure ratings of all subsea capping stacks must conform to industry standards set by API RP 17G, Section 8.

The available subsea capping stacks are rated to 10,000 psi or 15,000 psi.

7.2.2 Temperature Rating

API RP 17G specifies the temperature classification in which subsea capping stacks are designed to operate. Typically, the minimum temperature is the lowest ambient temperature the equipment is subjected to during operation, transportation, and preservation. The maximum temperature is encountered during flowing conditions.

According to API RP 17W, the minimum classification for pressure-containing and pressure-controlling materials should be a temperature classification of U (0°F [-18°C] to 250°F [121°C]). API RP 17G also provides information for the design and rating of equipment for use at elevated temperatures.

The MWCC 15,000-psi subsea capping stack is the only one that is rated to a temperature of 350°F.

7.2.3 Water Depth Rating

In accordance with API RP 17W, the subsea capping stack Basis of Design (BOD) must include the range and maximum operating depth for its application. The subsea capping stacks manufactured with a global perspective are rated to at least 10,000 ft.

The subsea capping stacks designed for the Arctic have different design requirements because they are designed for shallow waters (< 500 ft.) and low temperatures (-40°F). Currently, only one Arctic subsea capping stack (owned by Shell) is available.

7.2.4 Flow Capacity

The maximum flow capacity of a subsea capping stack is limited by the lesser of the following two parameters:

- Acceptable limit of erosion within the subsea capping stack
- Acceptable pressure drop within the subsea capping stack components

The flow from an incident well can have high concentrations of solids and can cause erosion of the subsea capping stack components. The subsea capping stack design should be analyzed using Computational Fluid Dynamics (CFD) to determine the areas of erosion. Critical erosion areas should be designed and tested in accordance with API Specification 6AV1 Class II for sandy service.

7.3 Interface Descriptions

Mechanical interface connections on any subsea capping stack are typically multifunctional and must interface with a variety of rig and vessel running tools and containment connection systems. The interface information must be documented and planned prior to any incident requiring the use of a subsea capping stack.

7.3.1 Attachment to Incident Well

The attachment point is mostly a user-defined, industry-recognized connection that conforms to the standards of API Specification 6A for Flange Connections and API RP 17G for Other Connections. The attachment is performed using an actuated hydraulic wellhead-style connector provided at the bottom of the subsea capping stack.

The subsea capping stack attachment point depends on the condition of the well. The three most likely subsea capping stack attachment points, which are listed in the recommended order of preference, are:

1. Top of the lower BOP mandrel – accessible if the LMRP is removed
2. Subsea wellhead – accessible if the BOP is removed

3. Riser adapter above the LMRP – accessible if the marine riser is removed

Figure 7.1 provides the typical connection points of the subsea capping stack to the incident well. The connection interface between the BOP and the LMRP may not match the wellhead and tree profile. Therefore, the subsea capping stack Owner provides additional interfacing tools (for example, adapter spools, spacer spools) with the subsea capping stack to maintain a connection with the incident well, depending on the situation.

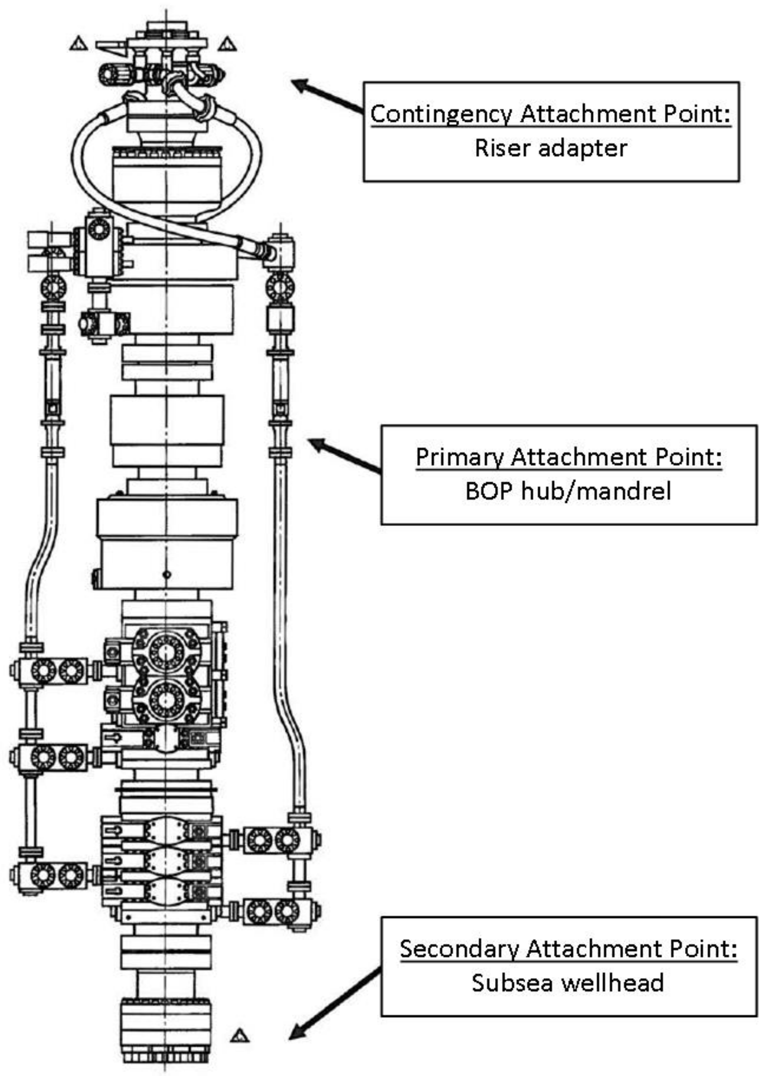


Figure 7.1: Typical Subsea Capping Stack Attachment Points [3]

7.3.2 Attachment of External Flow Paths

External flow equipment such as jumpers, manifolds, and risers, may interfere with the subsea capping stack for bullheading and killing the well or for flowing the incident well to a containment system. The attachment can be based on the flowline connection or hot stab technologies using an ROV. In either case, industry standard connections must be used to allow for maximum flexibility during the subsea capping incident.

It is possible that the flowline connection points and high flow hot stabs provided by subsea equipment vendors are proprietary in nature and are not convertible to a universal standard type. Therefore, subsea capping stack Owners must have the necessary connection equipment (for example, goosenecks, rigid jumpers, pressure caps, hot stabs, running tools) to connect the subsea capping stack to the intended containment system.

7.3.3 Attachment Interface at the Top of the Subsea Capping Stack

Depending on the requirements at the incident well, the top of the subsea capping stack may be connected to an additional subsea capping stack (or secondary cap) or to a containment system. For this reason, the top mandrel interface of the subsea capping stack must:

- Be pressure-containing.
- Be rated to the full working pressure of the subsea capping stack.
- Allow for attachment to the subsea hydraulic connector.

For single ram subsea capping stacks, the cap on the top interface acts as the secondary barrier. For dual ram subsea capping stacks, it is the tertiary barrier. The attachment interface at the top of the subsea capping stack must be an industry-recognized connection and must conform to API Specification 6A for Flange Connections and API RP 17G for Other Connections.

7.3.4 External Controls and Monitoring

An ROV primarily controls the subsea capping stacks. Data monitoring is also performed with ROV intervention using ROV-readable gauges.

7.4 Connectors

According to API RP 17W, the material and testing of all subsea capping stack connectors must conform to the relevant sections of API Specification 6A and API Specification 17D.

7.4.1 Wellhead Connector

The subsea capping stack has a hydraulically actuated wellhead connector that interfaces with the incident well. The connectors must conform to the maximum standard pressure rating according to API RP 17G.

7.4.2 Flowline Connector

'Cap and flow' subsea capping stacks require flowline connector systems. The flowline connector must have API standard flange interface on the flow spool outlets and downstream of any chokes.

7.4.3 Diversion Outlet Connection

The diversion outlet connection components must be industry standard size with rated working pressures in accordance with API RP 17G. The diversion outlets must be placed in a symmetrical configuration to minimize asymmetric thrust forces.

7.4.4 Fluid Injection Inlet Connections

The fluid injection inlet connection must be designed to the same specifications as the diversion outlet connection.

7.4.5 Dispersants, Chemicals, and Hydrate Injections

The design of subsea capping stacks includes chemical injection inlets. In accordance with API RP 17W, the subsea capping stack Manufacturer must design the inlets (such as number and size) in accordance with the chemical dispersant, and the hydrate inhibitor capacity. The optimum placement of inlets must be identified to enable efficient mixing.

7.5 Control System

For subsea capping stack control systems, API 16D, API RP 17G, and API Standard 53 ensure industry best practices, commonality of interfaces, fast closure of barrier devices, and the control of cap and flow scenario functions.

The subsea capping stack must provide fast closure of all barrier devices for the applicable water depths of the main bore and diversion outlets in accordance with API Standard 53. Surface control of the subsea capping stack with direct hydraulic power may be appropriate for subsea wells in shallow water. As the water depth increases, hydraulic flow rates, umbilical size and handling, and overall hydraulic response time may impair the performance of the subsea capping stack.

The major items that must be considered when designing a subsea capping stack control system are:

- Water depth of the intended operation
- Hydraulic fluid volumes to repeat component functions
- Function speed of closure devices
- ROV accessibility and visibility
- Flexibility to work within a variety of operating conditions
- Proximity to wellbore flow outlets

The control system must have the hydraulic capacity to perform functions such as operating the well connector, the main bore, and the diversion outlet closure devices. The hydraulic control system must have the ability to recharge while operating subsea. To reduce the size and weight of the subsea capping stack equipment, alternative sources or types of hydraulic fluid accumulation may be designed for the subsea capping stack.

The main bore vertical closure device (such as BOP rams or gate valves) used in a subsea capping stack must function quickly within the component's recommended maximum closing speed and no slower than that specified in API Standard 53.

The subsea capping stack hydraulic functions must be fitted with standard API RP 17H hot stab receptacles and must meet the API Standard 53 timing requirements. Figure 7.2 and Figure 7.3 show a Type C receptacle and a hot stab with an external locking mechanism.

The rams used as the vertical main bore closure device must be fitted with API RP 17H Type C (such as high flow) hot stab devices with external locking devices and must be clearly marked and labeled:

- On the equipment.
- On the subsea capping stack drawings and documentation.

Figure 7.2: API RP 17H Type C Receptacle

Figure 7.3: API RP 17H Type C, Hot Stab (High Flow)

Subsea capping stack interface components and gauges must be located within the normal view of the ROV camera. In accordance with API RP 17H, adequate 'grab handles' should be available to enable the ROV to remain stationary for engaging the interface item (such as hot stab) in adverse current conditions. For ROV-operated functions, the required operating torque should conform to API RP 17H.

7.6 Flow Isolation Barriers

A variety of closure devices are used to provide isolation under flowing conditions. The subsea capping stack Manufacturer must ensure that the closure device is qualified to shut in a flowing gas and a flowing oil incident well, as applicable [3].

Closure device qualification involves design and development verification and CFD analysis of the component design to determine the reliability under the expected operational conditions.

The design and development verification includes the following parameters:

- Pressure
- Temperature
- Fluid velocity
- Abrasive content

7.6.1 Ram

A ram used as the vertical bore closure device should be qualified to close on the maximum flow as defined by the subsea capping stack BOD. In the absence of a qualified ram, a second vertical bore closure device must be included. Any ram device incorporated in the subsea capping stack design should conform to API 16A and API Standard 53. For the most appropriate design, API RP 17W recommends using high temperature ram blocks and packers for the closure of flowing conditions in a gas or oil subsea capping scenario.

The second vertical bore device may be a valve to protect against gas migration past and permeation through the ram packing elements. The valve position is above the ram. Alternatively, a secondary cap installed on the top interface of the subsea capping stack can be used with designs that incorporate two non-qualified ram closure devices.

Ram designs should include position indicators and ram locks.

7.6.2 Valve

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 vertical bore closure device must be included.

Subsea capping stacks with valves should incorporate the capability for ROV overrides that are designed in conformance with API RP 17H and should include a visual position indicator. In addition, valves should be qualified for flow with solids and designed and tested to conform to API Specification 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.’

7.6.3 Secondary Cap

After a successful subsea well capping operation, a secondary sealing cap (for example, blind hydraulic connector, blind flange) should be locked on top of the subsea capping stack.

The secondary cap serves three main purposes:

1. Provides an additional sealing mechanism to the subsea capping stack
2. Protects the subsea capping stack's main vertical re-entry mandrel
3. Provides long-term protection and sealing while the relief wells are drilled

A secondary cap is also a means to check the pressure between the subsea capping stack's main vertical bore sealing element and the secondary cap. Pumping chemicals below the secondary sealing cap may be necessary to prevent the formation of hydrates or to vent trapped pressure.

7.7 Material Selection

Equipment must be constructed with metallic and non-metallic materials suitable for the respective material classification in conformance with API Specification 17D and API RP 17G. Choke assemblies must conform to API 16C.

Non-metallic materials (such as elastomers and thermoplastics), coatings, and greases must be suitable for the chemical environment, temperature, and pressure in which they are used. API Specification 17D, Annex M provides the material class with consideration to various environmental factors and production variables.

7.7.1 Arctic Considerations

All mechanical and structural components should be designed to the lowest expected preservation and testing temperature conditions. According to API Specification 6A, Charpy impact tests should be performed at or less than the lowest expected temperature on structural and mechanical components.

7.7.2 High Temperature Considerations

According to API Specification 17D and API RP 17G, all metallic and non-metallic subsea capping stack components should be constructed from materials designated for high temperature wells. Typically, subsea wellheads and production trees have operating temperatures ranging from 35°F (2°C) to 250°F (120°C). This temperature range may not be applicable for equipment used in Arctic environments.

The MWCC 15,000 psi subsea capping stack is the only one that is rated to a temperature of 350°F.

7.8 Design Load Analysis and Modeling

According to API RP 17W, the subsea capping stack Manufacturer must perform the design load analysis and fatigue modeling to verify that the subsea capping stack can be deployed and operated as designed [3].

A CFD analysis must be performed to confirm sufficient flow rate capacity of the subsea capping stack through the vertical bore and diversion outlets.

The different analyses to be performed are:

- Failure Mode Effects and Criticality Analysis (FMECA)
- Thermal Analysis
- Structural Analysis
- Fatigue Analysis
- Vertical Bore Flow Analysis
- Outlet Flow Analysis
- Centering and Uplift Force Modeling

7.8.1 Failure Mode Effects and Criticality Analysis (FMECA)

FMECA is performed to identify and document potential failure modes and associated mitigation measures related to subsea capping design. According to API RP 17W, FMECA should be reviewed and revised to reflect any repair, alteration, modification, or component replacement (not to exceed every 5 years).

7.8.2 Thermal Analysis

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

7.8.3 Structural Analysis

Structural analysis is performed using modeling or calculations to verify that the subsea capping stack's design and capacity are within material capability or grade, operational loads, and design factors. The analysis should consider the loads applied to the subsea capping stack throughout the life of the system.

At a minimum, the load cases that should be considered include:

- Fabrication and testing.
- Preservation.
- Maintenance and handling.
- Offshore installation and retrieval.
- In-place or operation.
- Transportation.
- Bending loads.
- Well pressure and applied pumping pressure.
- Structural loads associated with equipment interfacing to the subsea capping stack.

7.8.4 Fatigue Analysis

Fatigue modeling and calculations should be performed 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 RP 17G include, but are not limited to:

- A flow containment riser attached to the top of the subsea capping stack.
- Fatigue loads associated with installed equipment.
- Flow containment equipment attached to the diversion outlets.

7.8.5 Vertical Bore Flow Analysis

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

7.8.6 Outlet Flow Analysis

The diversion of flow may create lateral forces on the subsea capping stack and the existing well equipment. These forces should be analyzed to verify that the subsea capping stack's design can handle these forces. If there is an option to connect the subsea flowlines to the diversion outlet, the load capacity on the outlet should also be verified.

Dynamic fluid flow modeling that considers limiting factors (for example, erosion) should be performed to determine maximum flow through each diversion outlet with the vertical bore isolated. The design of the outlet(s) should account for erosion and hydrate plugging during the diversion outlet closure sequence up to and including closure of the final diversion outlet.

7.8.7 Centering and Uplift Force Modeling

API RP 17W states that ". . . *as the subsea capping stack enters the well plume, centering and uplift forces of the escaping hydrocarbons on the subsea capping stack should be modeled to optimize or modify stack designs and installation procedures. Features that may enable centering of subsea capping stack include funnels, guide wires, or other alignment devices*." [3]

7.9 Design Modularity

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 or deck testing. Planning for different modes of transportation should consider 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.

8.0 Subsea Capping Stack Operational Procedures

8.1 Introduction

This section provides a brief description of the steps to be followed for the notification, mobilization, deployment, and use of the subsea capping stack during a well control scenario. A review of the roles and responsibilities of the well containment consortiums and the RPs are also provided.

8.2 Incident Well Condition Assessment

The Incident Owner's assessment of the well condition identifies 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 during subsea capping operations.

A site assessment survey using an ROV determines the status of the wellhead, the BOP, and other components.

A survey of the immediate surrounding area is used to assess:

- The extent and nature of seabed debris.
- Riser status and any obstruction to the wellhead.
- General damage to the wellhead, BOP, or LMRP.
- BOP configuration and functionality.
- Status of the BOP control system and whether BOP manipulation is practical or advisable.
- Wellhead and BOP inclination.
- Seabed features that may interfere with well capping.
- Status of seabed currents and visibility.
- Locations of hydrocarbon release.
- Possible interface connection points available for subsea capping stacks.

8.2.1 Debris Removal

The removal of any debris and failed equipment surrounding the wellhead and failed BOP allows well capping activities to be safely and efficiently executed by reconnecting back to an adequate pressure-containing component.

A debris removal operation requires a recommended list of equipment for immediate callout, as discussed in Section 2.4.3 of this document.

During a deep water incident, several scenarios may be possible, and the Incident Owner (Operator) must have contingency procedures in place to handle the situation. Possible scenarios include [3]:

- A significant amount of the riser falls onto the seafloor. The riser is still connected to the LMRP but is bent over, and several pieces lie against the BOP stack. The BOP and wellhead are vertical.
- The riser has parted just above the BOP stack, at the flex joint, because of the high bending loads imparted to it as the disabled drill rig drifts off location at surface. The BOP and wellhead may be deflected from vertical.
- The riser is cut or disconnected just above the LMRP, but the LMRP remains connected to the BOP stack. The BOP and wellhead are vertical.
- The LMRP successfully and hydraulically disconnects, leaving the upper connector mandrel accessible for latching. The BOP and wellhead are in the vertical position.

Additional contingency measures (for example, the removal of the drill rig at the surface, wellhead straightening, BOP removal) are prudent.

8.2.2 Dispersant Application

Subsea application of dispersant at or near the wellhead is an integral part of the capping operation. It creates safer surface working conditions for response personnel and enhances the degradation of the oil. The subsea dispersant kits include dispersant wands; associated manifolds and hoses; and debris clearing equipment with cutting, grappling, and dragging tools for BOP accessibility, when necessary. If the well cannot be shut in, the subsea capping stack should capture and redirect the flow through risers and flexible jumpers to MCVs on the surface.

8.3 Notification and Callout

If a subsea capping stack is necessary to control the well, the Incident Owner must inform the subsea capping stack Owner and complete the required paperwork and the well condition assessment.

The steps followed during a well control event are:

1. The Incident Owner (Member) calls the subsea capping stack Owner.
2. The Incident Owner confirms the spill scenario and the required equipment:
   - Assets required
   - Location assets to be mobilized from
   - Transportation mode (air, sea, or land)

   - Special logistics/permits required for the country of disembarkation
   - Additional oil spill response equipment required
3. The Member completes the following paperwork:
   - Notification form
   - Mobilization or authorization form
   - Subsea Services Equipment selection form
4. The subsea capping stack Owner begins mobilization activities, including:
   - Subsea capping stack system testing.
   - Reconfiguration.
   - Disassembly.
5. The Incident Owner clarifies whether there are any special permits or import procedures required for the country of disembarkation and provides necessary documentation.
6. The subsea capping stack Owner takes responsibility for pre-deployment testing, loading, and handover of equipment to the Incident Owner.
7. The subsea capping stack Owner and the Incident Owner ensure adequate communication flow between themselves.

8.4 Pre-deployment Inspections and Testing

Pre-deployment inspection must be performed in accordance with the subsea capping stack Manufacturer and the Incident Owner recommended practices.

At a minimum, the subsea capping stack must be visually inspected for:

- Damage
- Leaks
- Valves, rams, and choke are in the correct positon for deployment
- Hot stab dummies are in place according to the deployment plan
- Accumulators are charged for water depth or according to the deployment plan
- The subsea capping stack control system is filled with the appropriate fluid volumes
- The correct adapter to interface with the planned attachment point is installed on the subsea capping stack
- Components used for shipping purposes are removed

Pre-deployment interface testing should include verification of the following:

- ROV tools
- Interfaces
- Power and communication interfaces

- Hydraulic supply interfaces
- Side outlet connections.

The subsea capping stack's main bore pressure testing should be considered before deployment.

8.5 Mobilization Methods

Mobilization of a subsea capping stack depends on the location of the incident well, the mode of transportation, and the departure and arrival country trading restrictions (cabotage laws). The amount of equipment to be mobilized depends on the conditions of the incident well. The two basic modes of transportation are by sea and by air.

8.5.1 Transportation by Sea

The subsea capping stacks that are dedicated to a region such as the MWCC, HWCG subsea capping stacks for the GOM, and the OSPRAG subsea capping stack for the UKCS are stored at a shore base and can be quickly transported to the incident site by sea. Pre-deployment testing is performed at the shore base, and the equipment is loaded onto a vessel for transporting it to the incident site. The subsea capping stack is deployed from the vessel to the incident wellhead/BOP and is operated to shut in or divert the flow of hydrocarbons. When a permanent means to kill the well is found (such as a relief well), the subsea capping stack is unlatched and transported to the storage area. Figure 8.1 provides the deployment lifecycles for transportation by sea.

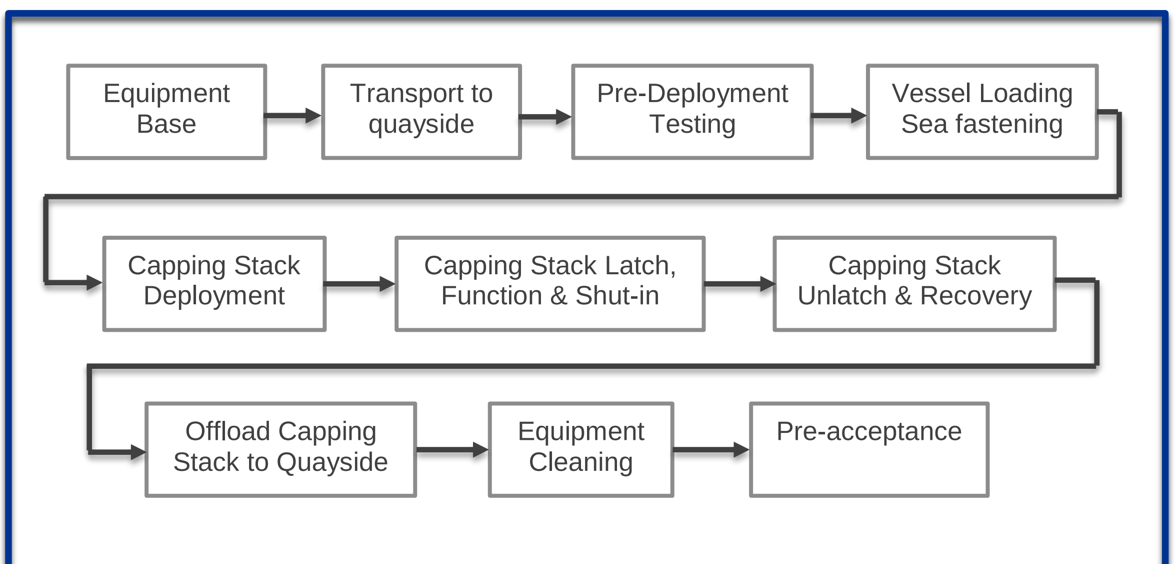


Figure 8.1: Transportation by Sea – Deployment Lifecycle

8.5.2 Transportation by Air

The subsea capping stacks that are used globally have modular designs which facilitate quick assembly and dis-assembly. For mobilization by air, the subsea capping stack must be dismantled and the equipment boxed in containers. The containers are transported to the airport by land. The aircraft is selected, depending on the airport of embarkation, the airport of disembarkation, and loading restrictions. When the equipment arrives at the airport in the incident region, it is transported by land to the local storage area for assembly. After the equipment is assembled, pre-deployment testing is performed. The subsea capping stack is mobilized to the quayside for loading onto a vessel of opportunity. The equipment will be deployed, and shut-in procedures will be followed.

The RP determines the mobilization method and the amount of equipment required, depending on the conditions of the incident well. Figure 8.2 provides the deployment lifecycle for transportation by air.

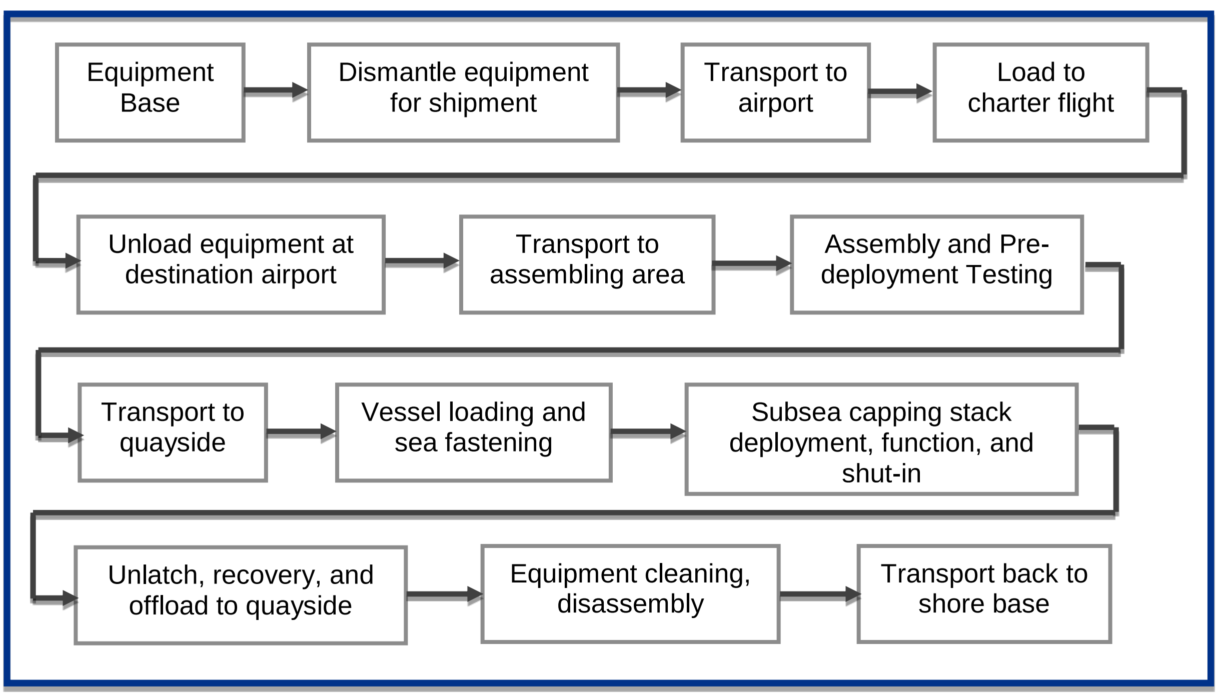


Figure 8.2: Transportation by Air – Deployment Lifecycle

The OSRL subsea capping stacks are stored in a built-in, deployable state on self-propelled towable trolleys as shown in Figure 8.3. The base dimensions of the

OSRL subsea capping stacks are 19.4 ft. x 20 ft. (5.9 m x 6.1 m), and the total weight (including the test stand) is approximately 324,079 pounds (147 metric tons) for the 15k psi and 233,690 pounds (106 metric tons) for the 10k psi. This configuration includes the H4 connector, the frame, and no spacer spool.

Figure 8.3: OSRL Subsea Capping Stack Stored on Towable Trolley [17]

Table 8.1 shows the different modes of transportation for OSRL SIRT and subsea capping stack equipment.

Table 8.1: OSRL Subsea Capping Stack Mobilization Methods

	Subsea Capping Stack	SIRT	Requirements
By land	Thirteen 20-ft. containers and up to 15 skids	• Five 20-ft. containers • Two 10-ft. containers • Four HFL racks • Four subsea accumulators • One spreader bar	The full SWIS suite can be containerized for land transportation. This is conducted using standard prime movers and ISO-compatible 40-ft. trailers.
By sea	• Requires deck space for the base dimensions of 19.36 x 20.01 ft. (5.9 x 6.1 m) • Total weight is approximately 326,284 pounds (148 metric tons) for the 15k psi subsea capping stack • This configuration includes H4 connector and frame but no spacer spool	Requires deck space for: • Five 20-ft. containers • Two 10-ft. containers • Four HFL racks • Four subsea accumulators • One spreader bar	During vessel selection, the following factors should be considered: • Dynamic positioning class • Draft • Crane capacity • Cargo deck capacity • Trading restrictions
By air	Thirteen 20-ft. containers and up to 15 skids	• Five 20-ft. containers • Two 10-ft. containers • Four HFL racks • Four subsea accumulators • One spreader bar	Aircraft is determined by several factors: • Airport of embarkation • Airport of disembarkation • Aircraft availability • Aircraft loading restrictions The Incident Owner's aircraft charter company should be consulted regarding number and type of aircraft.

The two WellCONTAINED subsea capping stacks are also air-transportable and can serve all regions of the world. The mobilization information of WellCONTAINED subsea capping stacks is not available at this time.

8.6 Deployment Procedure

If a blowout incident occurs and at the request of the Responsible Party the subsea capping stack Owner will initiate mobilization of its containment system, a vessel will transport the containment system to the incident site. After arriving onsite, the subsea capping stack is deployed from the installation vessel in one of three ways, depending on Operator preferences and available vessels:

1. Through the floor of the drill rig using a drill pipe.
2. On a wire of the installation vessel using a heave-compensated crane.
3. On a wire from the stern of an anchor-handling vessel using the A-frame.

After the subsea capping stack is latched onto the wellhead or BOP, the vertical main bore is closed using the blind rams or gate valves, and the flow of hydrocarbons is directed through the diverter outlets. The choke valve on each diverter outlet is sequentially closed to shut off the flow of hydrocarbons to the environment. During the choke valve closing procedure, the pressure in the well is monitored. If the pressure is higher than the maximum allowable, the choke valve closing operation is stopped. In this scenario, a containment system is attached to the subsea capping stack to capture and collect the hydrocarbons and transport them to the surface.

The deployment procedure is similar for most deep water capping operations. The procedures for Arctic conditions may be different because of the weather conditions, ice, and shallow water depths. No information is available on subsea capping stack deployment in Arctic environments.

8.7 Roles and Responsibilities

During a well control incident, the roles and responsibilities of the subsea capping stack Owner and the RP vary, depending on the consortium. The sharing of responsibilities in mobilization and deployment of the subsea capping stack for each consortium is provided in this section.

8.7.1 MWCC and the Responsible Party

In the event of a well control incident in the GOM, the RP (Member Company) works with the MWCC to access the capping and containment equipment required to stop the flow from the uncontrolled well. The MWCC will plan and supervise the mobilization, installation, and operation of its equipment on behalf of the RP.

The following services are provided by the MWCC in the event of an incident [37]:

- The MWCC works with and supports the RP. The RP may be part of the Unified

Command[21] (UC), which is composed of representative government agencies involved in the response. Mobilization of the system begins upon activation of the MWCC team under the direction of the RP and the UC.

- Before equipment from the MWCC's containment system can be deployed, the RP conducts an initial site assessment to determine a safe working environment for response operations and personnel. Part of the site assessment includes the removal (if possible) of debris that may hinder the safe installation of response equipment.
- When the RP and the MWCC determine the specific equipment and configuration needed at the well incident site, the MWCC's system will be mobilized from its two shore bases.
- The MWCC plans for and supervises the mobilization, installation, and operation of its equipment on behalf of the RP.
- The RP is responsible for debris removal and relief well drilling. The RP is also responsible for securing marine capture vessels, shuttle tankers, and surface clean-up, as well as for the interim collection.

In the event of an incident, the roles and responsibilities in Table 8.2 will apply.

Table 8.2: Roles and Responsibilities of MWCC and RP [37]

Marine Well Containment Company (MWCC)	Covered Entity (Responsible Party)
Conduct pre-deployment testing of equipment	Deliver key wellhead operating parameters
Deploy the Reservist Response Team	Remove incident site debris
Mobilize the equipment to quayside	Secure and manage drillship interim collection installation, operation, and recovery
Integrate Modular Capture Vessels (MCV) equipment, including MCV outfitting, commissioning, hook-up, and operation	Secure vessels necessary for deployment, installation, and operation of containment system equipment
Transport equipment to the incident site and install it subsea	Implement soft shut-in process design
Operate the incident site operation containment system	Conduct MCV lightering: secure offloading resources and disposal execution
Recover and refurbish equipment	Plan and manage simultaneous operations (SIMOPS)

[21] Unified Command is a team formed with members of the Responsible Party (RP), the capping stack owner, and regulators. Unified Command makes decisions during the event of an incident.

8.7.2 HWCG and the Responsible Party

HWCG's Mutual Aid program creates a shared pool of information, assets, and experts that is available to the member companies. The containment of a subsea well requires multiple problem-solving disciplines and an enormous commitment of resources, all of which are available through Mutual Aid. HWCG has contracts with more than 30 service companies to provide additional equipment and personnel during a subsea blowout response.

The RP is responsible for coordinating with HWCG member companies to gather the resources required for mobilizing and deploying an HWCG subsea capping stack. HWCG does not maintain the response teams for mobilizing a subsea capping stack; this is the responsibility of the RP. HWCG only supervises the mobilization and provides guidance as needed.

8.7.3 OSRL and the Responsible Party

OSRL works in tandem with the RP to ensure that an efficient and effective response is delivered in proportion to the incident. The OSRL Incident Manager coordinates the response through the Emergency Operations Center.

OSRL is responsible for mobilizing all SWIS equipment to a pre-determined handover point, either the quayside at the designated departure port or the cargo terminal at the designated departure airport. At this point, custody of all equipment transfers from OSRL to the Incident Owner or RP. After handover, the RP is responsible for the transportation, reassembly, testing, deployment, and operation of the subsea capping stack.

Upon completion of the operation, the RP is responsible for recovering the equipment and the reverse logistics involved in returning the equipment to OSRL at the handover point.

In the event of an incident, the roles and responsibilities in Table 8.3 will apply.

Table 8.3: Roles and Responsibilities of OSRL and RP [16]

Oil Spill Response Limited	Covered Entity (Responsible Party)
Provide access to capping and subsea dispersant, debris clearance, and BOP intervention equipment	Determine whether the system is appropriate for the intended use
Own, store, and maintain the equipment	Take full responsibility for the deployment of the system from the dockside or airport storage location and any subsequent deployment
Mobilize the equipment to the departure port or airport	Take responsibility for any repair or replacement arising from deployment
Have base personnel available to mobilize the equipment from the storage location to the departure port or airport	According to the requirements of the call-out process, the well Operator signs a Call Out Indemnity
Provide extra documentation for all equipment	Secure access to personnel to advise and assist with equipment operation and installation
Establish an internal response structure for the mobilization of resources	Secure access to suitable deployment and support vessels and ROVs
Provide generic operating guidelines, procedures, information	Secure access to suitable land, air, and sea transportation and logistics
—	Establish an Incident Command System and an Emergency Response Plan

Figure 8.4 illustrates OSRL and Incident Owner roles and responsibilities during an incident.

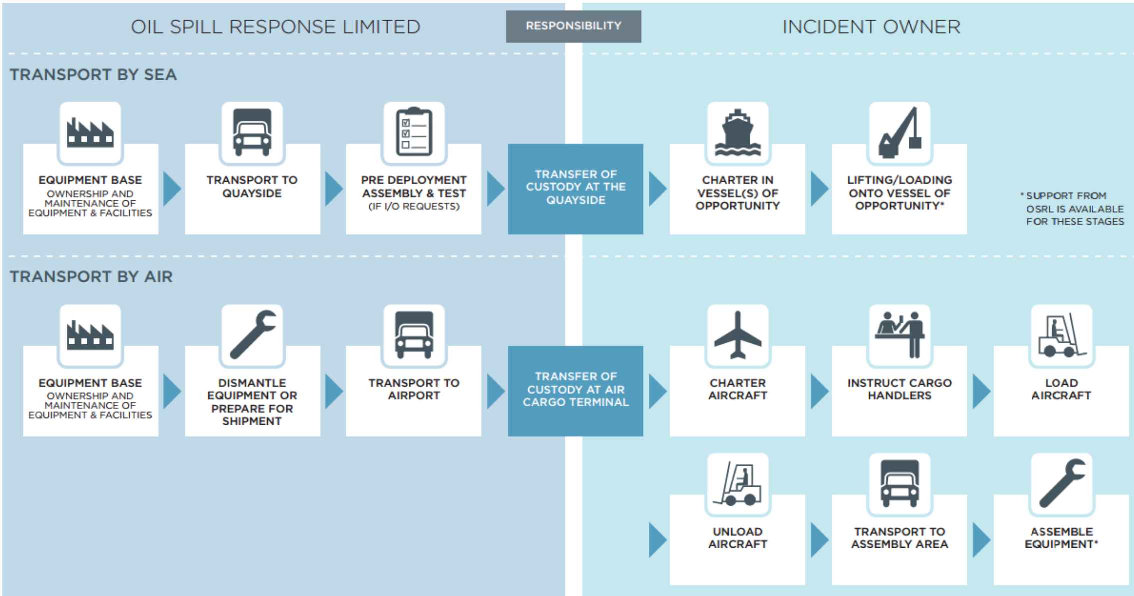


Figure 8.4: OSRL and Incident Owner (RP) Roles and Responsibilities During an Incident [16]

8.7.4 WellCONTAINED and the Responsible Party

Wild Well's WellCONTAINED is an integrated system with personnel who plan and prepare specialized equipment to respond to a global subsea source control event. Wild Well is involved in various stages of the well containment process, including configuration of the subsea capping stack equipment, mobilization, pre-deployment testing of the installation, and operation of the subsea capping stack system.

The RP is responsible for completing the required paperwork, securing quayside facilities and vessels, preparing the incident wellsite for subsea capping stack installation, and implementing the shut-in process.

In the event of an incident, the roles and responsibilities in Table 8.4 will apply.

Table 8.4: Roles and Responsibilities of Wild Well Control and RP

Wild Well Control	Covered Entity (Responsible Party)
Mobilize equipment to quayside or airport	Complete and send Emergency Mobilization Authorization Form (EMOB)
Mobilize deployment personnel	Determine mobilization of equipment into theater (air or sea)
Wild Well personnel to assemble and configure subsea capping stack according to client's specifications	Determine the subsea capping stack configuration (HC/H4)
Wild Well personnel to conduct pre-deployment testing of equipment at quayside	Secure quayside a facility for assembly and testing
Wild Well personnel to supervise the loading of equipment onto the deployment vessel at quayside	Provide quayside support for assembly and testing (material handling equipment, cranes, power)
Wild Well personnel to transit with equipment and conduct deployment operations	If necessary, conduct debris clearance
After the subsea capping stack is secured to the BOP or wellhead, Wild Well personnel commence shut-in operations according to the shut-in plan.	Source and secure deployment vessel
Recover and refurbish equipment when relief well operations are successfully completed	Commence sea fastening plan and approvals
	Implement shut-in process

9.0 Industry Survey Response

9.1 Introduction

WGK conducted industry surveys to assess the government and industry regulations, standards, and guidelines specific to the design, use, and deployment of subsea capping stacks. Three sets of survey questionnaires were developed with questions that were specifically related to subsea capping stack Manufacturers, Owners, and Operators. This section summarizes the responses received as part of the industry survey.

9.2 Subsea Capping Stack Manufacturer – Survey Response

9.2.1 Standards and Guidelines

The specifications, standards, and recommended practices that are applicable for the design, manufacture, and use of subsea capping stacks are listed in Table 9.1.

Table 9.1: Specifications, Standards, and Guidelines Used in the Design, Manufacture, and Use of Subsea Capping Stacks

Standard	Title
API 6A/ISO 10423	Specification for Wellhead and Christmas Tree Equipment
API 6D	Specification for Pipeline Valves
API 16A/ISO 13533	Specification for Drill-through Equipment
API 16D	Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment
API 17A/ISO 13628-1	Recommended Practice for Design and Operation of Subsea Production Systems
API 17D/ISO 13628-4	Specification for Subsea Wellhead and Christmas Tree Equipment
API 17TR8	High-pressure and High-temperature Design Guidelines
API 17W	Recommended Practice for Subsea Capping Stacks
API 14D/ISO 10423	Specification for Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service
API RP 2A - WSD	Recommended Practice for Planning, Designing, and Constructing Fixed Offshore Platforms – Working Stress Design
API 53	Blowout Prevention Equipment Systems for Drilling Wells
DNV RP B401 (2005)	Cathodic Protection Design
NACE MR0175/ ISO 15156	Petroleum and Natural Gas Industries Materials for Use in H_2S Containing Environments in Oil and Gas Production
API RP 17H	Design and Operation of Subsea Production Systems – ROV Interfaces on Subsea Production Systems
ISO 13628-5	Design and Operation of Subsea Production Systems – Part 5: Subsea Umbilicals
DNV Cert No. 2.7-1	Offshore Containers (DNV certification note on lifting)
DNV Cert No. 2.7-3	Portable Offshore Units (DNV certification note on lifting)
SAE AS 4059	Contamination Classification for Hydraulic Fluids

9.2.2 Regional Requirements

The design requirements for a subsea capping stack depend on the region or regions in which the subsea capping stack will operate. For example, the GOM has the broadest range of requirements, such as:

- Flow ranges from 50,000 bpd to 300,000 bpd.
- Pressure ranges from 10,000 psi to 20,000 psi.
- Temperature ranges from -40°F to 350°F.
- Addition of electrohydraulic (EH)/Multiplex (MUX) system for topside control.
- Subsea capping stack footprints that are smaller on TLP and spar wells.

The requirements for the North Sea are mid-range, compared to the GOM. The Arctic region requires pre-installed drill-through provisions and a locally available subsea capping stack. Low temperatures (-40°F) are unique to the Arctic, so fabrication materials for the subsea capping stack need to be selected accordingly.

9.2.3 Standardization Needs

The companies that participated in the surveys did not recommend standardization of subsea capping stacks. Similar to BOPs, subsea capping stacks vary significantly in design, size, and capabilities. Like other oilfield tools, allowing for flexibility in designs contributes to the best in design features, design practices, and fabrication methods. The ability to have more than one ‘tool’ to perform the same function creates redundancy and provides secondary options when needed.

One of the subsea capping stack Manufacturers made the following suggestions:

- API flanges and bolted structural connections should be used for the assembly of components within the subsea capping stack.
- The connections used to assemble subsea capping stacks within a containment system should be standardized. This will allow different subsea capping stacks to be substituted into the same surrounding containment equipment.
- Existing design, readily available drilling, and production components should be used when possible.

Overall, there could be a degree of standardization, but considerations must be application-specific. The primary considerations are quick mobilization, straightforward installation, and simple operation.

9.2.4 Fabrication Time

The average time from receipt of the order to the delivery of a new subsea capping stack is approximately 9 to 12 months, but it can take up to two years. The delivery time varies, depending on the complexity of the subsea capping stack design and the availability of parts.

9.2.5 Maintenance and Testing

While delivering the newly assembled subsea capping stack to the Owner, the Manufacturer provides the operation and maintenance manuals with procedures for the subsea capping stack. The subsea capping stack Owner is responsible for storage, maintenance, testing, and inspection of the equipment. For most of the currently available subsea capping stacks, maintenance is performed by either the stack Manufacturer or a third party under the supervision of the subsea capping stack Owner. For example, OSRL subsea capping stacks are constructed by Trendsetter Engineering, and Trendsetter is contracted to test and inspect these subsea capping stacks.

9.2.6 Improving Logistics

Suggestions for improving logistics and new technology development include:

- Use gate valves instead of rams, which reduces the weight and size of the subsea capping stack and eliminates the need for Subsea Accumulator Module (SAM) units. The gate valves can be used only for smaller main bore sizes, as large bore gate valves are currently not available in the industry.
- Expand the use of acoustic controls.

9.3 Subsea Capping Stack Owner – Survey Response

The role of a well containment consortium is to support its member companies by providing expertise, resources, and equipment during a well control incident. Each consortium has different methods and procedures in place for the mobilization and installation of the subsea capping stack equipment:

- MWCC owns the equipment and resources required to mobilize and use the subsea capping stack. MWCC provides the response team and expertise needed to prepare, mobilize, install, and operate a subsea capping stack in a well control scenario.
- HWCG LLC facilitates mobilization of its contractually dedicated equipment. HWCG LLC also initiates Mutual Aid protocols as an integral part of its response to a deep water blowout. HWCG LLC personnel offer response advice to the member

company according to the HWCG Well Containment Plan and the Incident Management Handbook. The Well Containment Plan contains information related to a blowout situation, the subsea capping stack, and supporting equipment (debris removal and dispersant) appropriate for the particular well. The HWCG Incident Management Handbook provides guidance on managing the team within the accepted incident command system.

- OSRL owns the equipment and has personnel to mobilize the equipment to the departure port or airport. It is then the responsibility of the member company to mobilize the equipment to the incident site, use it, and return it to OSRL.
- WellCONTAINED owns the equipment and has the personnel required to mobilize and operate a subsea capping stack in a blowout scenario.

All consortiums are responsible for storing, maintaining, and testing their subsea capping stack equipment. They contract third parties to perform the periodic maintenance and testing under the consortiums' supervision.

Although the currently available subsea capping stacks were designed before API RP 17W [3], the consortiums that serve the GOM participated in the development of API RP 17W, and they follow those recommendations. Construction of new subsea capping stacks will take API RP 17W into consideration.

9.4 Operator – Survey Response

Operators must submit an APD to BSEE before starting drilling operations. The APD includes documentation that the Operator has access to the equipment required to respond to a well containment incident on a particular well. BSEE must approve the APD before the Operator starts drilling.

There are challenges associated with mobilization and deployment of subsea capping stacks. Finding the right vessel and having a proper sea fastening is critical. Weather conditions may also present a challenge for deployment of the subsea capping stack because of its size and weight.

The lessons learned from previous deployments include:

- The crane on the transport vessel should be suitable for deploying the subsea capping stack.
- Sea fastening of the subsea capping stack on the vessel must be done carefully.
- A vessel with a moon pool is recommended for deployment in higher sea states.
- Substantial planning and resources are required in addition to the document control systems and logistics.

- The crew involved in the subsea capping stack mobilization and deployment must be well trained to respond to a well control incident.
- Because the equipment can have limitations, possible upgrades must be considered.
- The Operator must obtain approval for the use of dispersants.

10.0 Subsea Capping Stack Maintenance and Testing Procedures

10.1 Introduction

Regular, comprehensive maintenance and testing of the subsea capping stack equipment, including response personnel training, is important to ensure that the well containment equipment remains operable. The subsea capping stack Owner maintains the subsea capping stack in a readily deployable state by performing periodic inspections and following the preservation plans provided by the subsea capping stack Manufacturer. This section provides a detailed review of the different tests, maintenance procedures, and inspection and preservation plans.

10.2 Maintenance and Testing

Periodic maintenance and testing are critical for the long-term preservation of subsea capping stacks. All tests and maintenance functions are performed at the storage facility.

A series of testing programs are in place to verify:

- That all functions are operationally ready for deployment, including all possible control systems.
- The pressure integrity of the subsea capping stack equipment.

The subsea capping stack Owner must complete the test programs, including visual inspections, lifting gear recertification, function tests, pressure tests, maintenance practices, fluid testing for cleanliness and degradation, and operational mobilization drills.

The subsea capping stack Owner must maintain a testing document that includes the testing requirements, testing frequency, and testing acceptance criteria.

10.2.1 Testing Types and Test Criteria

The different types of tests performed include function testing, pressure testing, drift testing, ram testing, valve testing, and choke tests.

Function Testing: A function test on a piece of equipment or a system verifies that the intended operation is within the design parameters. Function tests must comply with the requirements of API Standard 53.

Function tests verify:

- The fit, form, and function of subsea capping stacks.
- Correct installation, handling, and operating procedures.

Function tests are performed on all the major components of the subsea capping stack (for example, vector connectors, flowline connector, accumulator, wellhead connector, secondary containment cap, blind rams, and valves).

Pressure Testing: A pressure test on a piece of equipment or system verifies the functionality of the pressure-retaining connectors and checks for any leaks. The acceptance criteria of pressure tests must conform to API Specification 17D and API Standard 53.

Pressure tests conducted on a subsea capping stack during a subsea capping event must be conducted at the Rated Working Pressure (RWP) of the stack or to the incident well's calculated shut-in mudline pressure, whichever is lower.

Pressure test frequency depends on two scenarios:

1. During preservation, as necessary, to ensure that the subsea capping stack is fit for service and available for callout for a minimum of every 12 months. Typically, pressure testing is performed every six months. The criteria may differ for each component of the subsea capping stack.
2. After the disconnection or repair of any pressure-containing or pressure-controlling element in the subsea capping stack, limited to the affected component

Hydraulic chamber pressure tests are also performed according to the subsea capping stack Manufacturer's RWP and in conformance with API Standard 53.

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.

Drift Testing: Drift testing of subsea capping stacks, which verifies that the bore is clear of obstructions, is performed by passing a drift mandrel through the bore of the assembly. A drift test is required on rams, valves, hydraulic connectors, drilling spools, and adapters. Drift testing, which is documented as part of the subsea capping stack acceptance criteria, follows remanufacturing operations that affect the vertical bores. Drift tests must be performed in accordance with API Specification 6A or API 16A.

Ram Testing: If rams are used in a subsea capping stack, the rams must undergo pressure and function testing in conformance with API 16A.

Pressures vary, depending on the type of test. For low pressure tests, the pressure is in the range of 200 to 300 psi; for high pressure tests, it can be up to 15,000 psi.

Typically, ram tests are performed, visually verified, and documented:

- Every six months, at a minimum.
- When equipment is repaired or remanufactured.
- In accordance with the subsea capping stack Owner's maintenance program.

Valve Testing: If valves are used in a subsea capping stack, the valves must undergo pressure and function testing in conformance with API Specification 6A. This testing also includes the verification of any position indicator, and it determines the sealing capabilities of the assembly.

Typically, valve tests are performed, visually verified, and documented:

- Every six months, at a minimum.
- When equipment is repaired or remanufactured.
- In accordance with the subsea capping stack Owner's maintenance program.

Choke Tests: The choke body pressure test and the choke function test occur in one-year increments at a minimum and after any repair or maintenance of the choke. Choke tests involve function testing and pressure testing of the choke body, connections, and seals.

10.2.2 Maintenance

Maintenance tasks include inspection and testing of various subsea capping stack components. The planned maintenance schedules followed for each component of the subsea capping stack include:

- Prevention of elastomer degradation and overall corrosion.
- Assurance that the subsea capping stack is ready for mobilization when required and without additional maintenance or repair.
- Performance trending that is critical to uncovering any changes in the operability of the equipment.

In conformance with API RP 17W, the following items must be inspected periodically to maintain the subsea capping stack:

- Non-metallic goods
- API end connections

- Critical sealing areas
- Ring gaskets
- Closure bolting
- Cleaning and coating
- Repair and remanufacture of the subsea capping stack

Table 10.1 provides the OSRL subsea capping stack maintenance schedule.

10.3 Subsea Capping Stack Inspection

An inspection plan ensures the long-term preservation and readiness of the subsea capping stack. The frequency of inspection depends on the equipment preservation conditions and may change, based on the trends and experiences of the service and maintenance programs. The subsea capping stack Owner is responsible for the periodic testing and inspection of subsea capping stacks. In most cases, the subsea capping stack Manufacturer performs the inspection under the supervision of the subsea capping stack Owner.

The subsea capping stack undergoes a pre-shipping inspection program at the manufacturing facility. The inspection ensures that the subsea capping stack is ready for shipping and handling, and that the fluids are drained, if necessary.

10.3.1 At the Preservation Facility

Upon receipt of the subsea capping stack at the long-term preservation location, the subsea capping stack Owner examines the subsea capping stack and documents a receiving inspection program.

At a minimum, the receiving inspection includes the following activities:

- Inspection for transportation and handling damages
- Inspection for completeness and condition of delivery
- Inspection and confirmation that the delivery adheres to the scope of supply
- Verification that each individual subsea capping stack component is marked with a serial number, or unique identifier, according to the quality plan

10.3.2 At Quayside

Following shipment from the preservation location, the subsea capping stack should undergo a predetermined receiving inspection program at quayside to verify its readiness for deployment.

The inspection will be conducted in accordance with pre-developed, receiving inspection procedures and will include:

- Inspection for transportation and handling damages.
- Inspection for completeness of delivery (for example, hydraulic power unit, operating fluids, running tools, tools and spare parts, handling slings, shackles).

10.4 Subsea Capping Stack Preservation

Long-term preservation of the subsea capping stack ensures that the equipment is always ready for deployment. The subsea capping stack Manufacturer must generate a long-term preservation plan with input from the subsea capping stack Owner.

10.4.1 Location

At a minimum, the preservation location must include the following criteria:

- Security and protection of all subsea capping stack components
- Adequate facility height to allow the use of a crane for equipment handling
- Maintenance requirements
- Function and pressure testing requirements
- Long-term preservation requirements
- Transportation requirements to base/quayside/airport

10.4.2 Storage

Storage for the subsea capping stacks must be indoors. If outside preservation is the only option, the facility and location should avoid flooding, ultraviolet (UV) radiation, dust, rain, and ice. Only inside preservation provides a measure of protection against extreme heat, cold, and unexpected weather events. Tarps can be used indoors as an effective measure against dust, but tarps used outdoors may trap moisture and lead to corrosion.

During storage, the physical properties of most rubber and elastomeric materials change with age and ultimately become unserviceable. Examples include excessive hardening, softening, cracking, or other surface degradation. The amount of degradation varies with time, environmental conditions, and mechanical stress. Expired rubber goods or elastomeric components (such as the Manufacturer's recommended expiration date) must be discarded and prohibited from use in subsea capping stacks. According to Original Equipment Manufacturer (OEM) recommendations, elastomeric materials should be stored in ambient temperature conditions.

10.4.3 Preservation Fluids

Water-based hydraulic preservation fluids specifically designed for long-term preservation must be used. The preservation fluids must be inspected periodically. If the fluids are found to be ineffective, they must be replaced.

10.4.4 Spare Parts

Spare parts are sensitive to temperature or humidity and must be preserved to avoid a limited shelf life.

10.4.5 OSRL 15K Subsea Capping Stack Preservation, Maintenance, and Testing Procedures

Table 10.1 provides the maintenance schedule of an OSRL 15K subsea capping stack.

Table 10.1: OSRL 15K Subsea Capping Stack Maintenance Schedule

Step	Monthly	Quarterly	Semi-Annually	Annually
1 – Visual Inspection for Corrosion and Damage				
Conduct visual inspection for corrosion and damage	Y	Y	Y	Y
2 – Bottom H4 Connector Function and Pressure Test, Drift Test, and OEM Recommended				
Conduct drift test			Y	Y
Lubricate bottom H4 connector				Y
Function test bottom H4 connector		Y	Y	Y
Pressure test bottom H4 connector			Y	Y
3 – Vector Connectors #1-4 Function Test				
Conduct vector connectors function test		Y	Y	Y
4 – Vector Connectors #1-4 Back Seal Test				
Conduct vector connectors back seal test		Y	Y	Y

Step	Monthly	Quarterly	Semi-Annually	Annually
5 – Bottom H4 Connector Test for Seal Retain/Release				
Conduct bottom H4 connector test for seal retain/release		Y	Y	Y
6 – Secondary Containment Cap Function Test				
Conduct secondary containment cap function test		Y	Y	Y
7 – Secondary Containment Cap Test for Seal Retain/Release				
Conduct secondary containment cap test for seal retain/release		Y	Y	Y
8 – Fill Bore with Fluid				
Fill the bore with fluid			Y	Y
9 – Secondary Barrier Test Procedure				
Conduct secondary barrier test procedure			Y	Y
10 – Intermediate Barrier Pressure and Function Test				
Conduct intermediate barrier pressure and function test			Y	Y
11 – Primary Barrier Function and Pressure Test				
Verify/remove hot stabs for secondary connector ROV			Y	Y
Conduct primary barrier function test			Y	Y
Close 5-inch gate valves			Y	Y
Vent via hose connected to hot stabs from secondary			Y	Y
Close ram		Y	Y	Y

Step	Monthly	Quarterly	Semi-Annually	Annually
Close 5-inch gate valves, and open bleed valves			Y	Y
Conduct primary barrier pressure test			Y	Y
Open ram		Y	Y	Y
Close vent valves			Y	Y
12- 5-inch Gate Valves Function Test				
Conduct 5-inch gate valves function test		Y	Y	Y
13 – 5-inch Choke Valve Function Test				
Conduct 5-inch choke valve function test		Y	Y	Y
14 – Running Tool				
Pick up and inspect running tool		Y	Y	Y
15 – Annual Rigging Certification				
Conduct annual rigging certification				Y
16 – Inspect Ram Cavities and Seals				
Inspect ram cavities and seals				Y

Detailed Procedures of Each Test

Bottom H4 Connector Function, Pressure, and Drift Test

1. Drain the bore of fluid.
2. Rig up the connector for the drift test; lower the drift into the bore, and pick up the drift from the bore.
3. Open and remove vector connectors #1 and #4.
4. Pull a fluid sample for testing.
5. Unlatch the bottom H4 connector.
6. Move the subsea capping stack into the inspection stand.
7. Check the tubing and fittings for leaks.

8. Lubricate the bottom of the H4 connector.
9. Move the subsea capping stack onto the test stand.
10. Latch the Bottom H4 Connector (4x).

Vector Connectors Function Test

1. Open the vector connector (#1).
2. Close the vector connector (#1).
3. Repeat for vector connectors (#2-4).

Vector Connectors Back Seal Test

1. Increase the pressure to 1,500 psi on the vector connector (#1).
2. Monitor and chart pressure for 10 minutes.
3. Repeat for vector connectors (#2-4).

Bottom H4 Connector Test for Seal Retain/Release

1. Seal and retain the bottom H4 connector.
2. Check the tubing and fittings for leaks.
3. Seal and release the bottom H4 connector.

Secondary Containment Cap Function Test

1. Unlatch the secondary containment cap,
2. Check the tubing and fittings for leaks.
3. Latch the secondary containment cap.

Secondary Containment Cap Test for Seal Retain/Release

1. Seal and retain the secondary containment cap.
2. Check the tubing and fittings for leaks.
3. Seal and release the secondary containment cap.

Secondary Barrier Test

1. Blank off the elbows and chokes.
2. Open the 5-in. gate valves.
3. Verify that the dummy hot stabs are installed.
4. Open the ½-in. isolation valves.
5. Increase the pressure to 15,000 psi and record the pressure readings.

Intermediate Barrier Pressure and Function Test

1. Close the ½-in. isolation valves.
2. Remove the dummy hot stabs.
3. Apply pressure to 200 – 300 psi and record the pressure readings.
4. Apply pressure to 15,000 psi and record the pressure readings.

Primary Barrier Pressure and Function Test

1. Remove the dummy hot stabs.
2. Open the ½-in. isolation valves and install the hot stabs on the secondary containment cap.
3. Apply 1,500 psi pressure to the system.
4. Close the blind ram.
5. Check the tubings and fittings for leaks.
6. Close the 5-in. gate valves.
7. Open the bleed valves.
8. Apply pressure to 200 – 300 psi and record the pressure readings.
9. Apply pressure to 15,000 psi and record the pressure readings.
10. Open the blind ram.
11. Check the tubing and fittings for leaks.
12. Close the ½-in.isolation valves.
13. Close the vent valves on the block elbows.

5-in. Gate Valves Function Test

Open gate valves (#1 – 4)

5-in. Choke Valves Function Test

1. Close the choke valve (#1).
2. Open the choke valve (#1).
3. Repeat for choke valves (#2 and 3).

Running Tool Function Test

1. Latch the running tool.
2. Check the tubing and fittings for leaks.
3. Unlatch the running tool.

11.0 Subsea Capping Stack Deployment Demonstrations

11.1 Introduction

Subsea capping stack consortiums that serve the GOM have demonstrated their well containment capabilities in simulated well control scenarios. The information related to the demonstration exercises is provided in this section.

11.2 MWCC Subsea Capping Stack Deployment Demonstration

In July 2012, at the request of BSEE, the MWCC partnered with member company Shell Oil to perform a demonstration of MWCC well containment capabilities. The goal of the demonstration was to prove to federal regulators that MWCC:

- Is ready to respond to well control incidents.
- Has the appropriate procedures in place.
- Provides equipment that can safely and efficiently respond deep water well control incidents.

11.2.1 Test Description

MWCC assembled its response team in the Emergency Response Center, where details of the demonstration were provided. The subsea capping stack, which stands roughly 30 ft. tall and weighs approximately 100 tons, was transported from the ASCO facility in Houston to the Greensport dock. While at Greensport, the secondary containment cap was installed and pre-deployment tests were performed. Additional ancillary equipment, including the hydraulic accumulator and four vector connectors, was shipped to Port Fourchon, where it was loaded onto the vessel for deployment [42]. (Refer to Figure 11.1 for a map of the simulated wellhead region.)

At the Greenport dock, a crane with a 500-ton lift capacity was used to lift and move the subsea capping stack to the Houston ship channel, where it was lowered onto the Laney Chouest[22]. The subsea capping stack then underwent a simulated deployment using the vessel's A-frame to lower the subsea capping stack just above the water line. The subsea capping stack was then sea-fastened onto a shipping stand and transported 304 miles offshore to simulated deep water well in the GOM.

When the capping stack arrived offshore, it was lowered approximately 6,900 ft. on a wire, using a heave compensated landing system (HCLS), from the back of the vessel

[22] *Laney Chouest* is an offshore supply vessel owned by Edison Chouest Offshore.

onto the simulated wellhead. The subsea capping stack landed and latched onto the simulated wellhead, where all necessary functions were completed. Pressure tests were performed to confirm the equipment's ability to safely and effectively cap a well. The mobilization, function, and pressure testing performed as expected and within the anticipated timeline. The subsea capping stack and ancillary equipment were then transported back to shore, where they are stored and maintained in a ready state.

Figure 11.1: Map Showing Simulated Wellhead Region

During the course of this exercise, BSEE inspectors and engineers monitored the demonstration from MWCC headquarters. Additionally, the BSEE director met with MWCC and Shell throughout the demonstration to witness the various phases of system deployment and participated in daily Unified Command (UC) briefings with the U.S. DOI. BSEE inspectors were staged at each work location to monitor and endorse the planned activities.

MWCC successfully demonstrated the ability to cap a well in the following ways:

- Deployment was executed with no recordable incidents and within the anticipated timeline.
- The arrival of the response equipment was completed on the first day of operations.
- The subsea capping stack was mobilized and pre-deployment testing was completed.
- The subsea capping stack was deployed using HCLS.
- Subsea capping stack function and pressure testing were demonstrated.

- The well containment screening tool and flow modeling established pressure response ranges for a simulated well.
- Video and pressure data were available for monitoring and decision making.
- The source control branch managed the overall response operations.

11.2.2 Test Results

Through this demonstration, the MWCC confirmed its ability to safely and effectively respond to a well control incident in the deep water GOM by successfully fulfilling the BSEE's requirements for the specified scenario. The success of the demonstration resulted from a strong collaboration between government and industry, particularly MWCC members.

11.3 HWCG Subsea Capping Stack Deployment Demonstration

The BSEE; Noble Energy, Inc.; and HWCG LLC have successfully completed the full-scale deployment of critical well control equipment to assess Noble Energy's ability to respond to a potential subsea incident in the deep water GOM [38].

The unannounced deployment drill, which was undertaken at the direction of BSEE on April 30, 2013, tested the HWCG subsea capping stack system—a 20-ft. tall, 146,000-pound piece of equipment similar to the one that stopped the flow of oil from the Macondo well following the Macondo oil spill in 2010. During this exercise, the subsea capping stack was deployed in more than 5,000 ft. of water in the GOM. When it reached the site, the system was lowered to a simulated wellhead (a pre-set parking pile) on the ocean floor, connected to the wellhead, and pressurized to 8,400 psi.

The BSEE, the U.S. Coast Guard, the Louisiana Offshore Coordinator's Office, and Noble Energy combined unique perspectives in a Unified Command structure to achieve a shared goal. Through coordination within the Incident Command System structure, all objectives were met [39].

BSEE engineers, inspectors, and oil spill response specialists have evaluated the deployment operations and identified lessons learned as the bureau continues its efforts to improve safety and environmental protection across the offshore oil and natural gas industry.

HWCG LLC's ability to quickly and effectively respond to a call from Noble Energy or any other Operator in the consortium has been made possible by a combination of the Mutual Aid agreement and the contracts in place for equipment that is staffed and working in the GOM each day.

12.0 Recommended Regulations for Subsea Capping Stacks

12.1 Introduction

WGK has developed the subsea capping stack recommended regulations with support and feedback from the well containment consortiums and the subsea capping stack manufacturing companies. This section provides the draft subsea capping stack regulations and recommends to BSEE how and where these regulations should be incorporated into 30 CFR 250 [33].

12.2 Recommended Location for Subsea Capping Stack Regulations in 30 CFR 250

WGK based the subsea capping stack recommended regulations on the current regulations and used the same numbering and format. WGK recommends that the sections in Table 12.1 be incorporated into 30 CFR 250 [33]. Table 12.1 also provides the subsea capping stack section titles to be included and the justification for each.

WGK considered BSEE's Proposed Rule(s) when developing the subsea capping stack recommended regulations but did not follow the numbering in the Proposed Rule(s).

Table 12.1: Recommended Sections to Be Incorporated in 30 CFR 250

30 CFR 250 Location	Recommended Section	Justification
Subpart A – General Authority and Definition of Terms *§250.105 Definitions*	Subsea capping stack definition	Subsea capping stack system definition is recommended to be included as part of definitions
Subpart A – General References *§250.198 Documents incorporated by reference, Paragraph (h)*	API 17H incorporated as reference	API 17H is referenced in the subsea capping stack regulations and should be included in this section.
Subpart D – Oil and Gas Drilling Operations Applying for a Permit to Drill	Subsea capping stack information to be included in the APD	Provides subsea capping stack system documentation as required by BSEE to issue a Permit to Drill.
Subpart D – Oil and Gas Drilling Operations	Subsea Capping Stack System Requirements	This section will have new regulations for subsea capping stacks.

Subpart A, §250.105 provides definitions for the terms used in 30 CFR 250 and will be useful to incorporate its subsea capping stack definition.

Subpart A, §250.198 lists the documents incorporated by reference in 30 CFR 250. The documents, which are organized based on the publishing organization, are:

- Paragraph (e) – provides reference documents published by the American Concrete Institute (ACI)
- Paragraph (f) – provides reference documents published by the American Institute of Steel Construction, Inc. (AISC)
- Paragraph (g) – provides reference documents published by the American National Standards Institute (ANSI)
- Paragraph (h) – provides reference documents published by the American Petroleum Institute (API).

WGK recommends that API 17H be included under paragraph (h).

Subpart D, §250.410 thru §250.419 provides the detailed procedures, requirements, and documentation for BSEE to approve an APD. Because this section currently does not have information related to subsea capping stacks, WGK recommends that this information be included, as shown in Table 12.2. Currently, Operators are submitting subsea capping stack documentation to BSEE in accordance with NTL 2010-N10.

Table 12.2: Recommended Location for Subsea Capping Stack APD Information

Subpart D - Oil and Gas Drilling Operations Applying for a Permit to Drill		
Current Regulation	§250.410	How do I obtain approval to drill a well?
	§250.411	What information must I submit with my application?
	§250.412	What requirements must the location plat meet?
	§250.413	What must my description of well drilling design criteria address?
	§250.414	What must my drilling prognosis include?
	§250.415	What must my casing and cementing programs include?
	§250.416	What must I include in the diverter and BOP descriptions?
	§250.417	What must I provide if I plan to use a mobile offshore drilling unit (MODU)?
	§250.418	What additional information must I submit with my APD?
Recommended Regulation	**§250.419**	**What must I include in the subsea capping stack system descriptions?**

Subpart D has different sections, such as Diverter System Requirements and BOP System Requirements, and WGK therefore recommends that there be a separate section for subsea capping stack System Requirements. Table 12.3 provides the recommended location and the CFR numbering for this proposed section.

Table 12.3: Recommended Location – Subsea Capping Stack System Requirements

Subpart D – Oil and Gas Drilling Operations		
	Section Title	**CFR Number**
Current Regulations	General Requirements	§250.400 thru §250.409
	Applying for a Permit to Drill	§250.410 thru §250.418
	Casing and Cementing Requirements	§250.420 thru §250.428
	Diverter System Requirements	§250.430 thru §250.434
	Blowout Preventer (BOP) System Requirements	§250.440 thru §250.451
	Drilling Fluid Requirements	§250.455 thru §250.459
	Other Drilling Requirements	§250.460 thru §250.463
	Applying for a Permit to Modify and Well Records	§250.465 thru §250.469
Recommended Regulation	**Subsea Capping Stack System Requirements**	**§250.480 thru §250.485**
Current Regulation	Hydrogen Sulfide	§250.490

12.3 Recommended Subsea Capping Stack Regulations

WGK has drafted the recommended subsea capping stack regulatory guidelines in a format which is similar to the BOP regulations that are currently available. Because the subsea capping stack design and usage differ from the BOPs, their regulations have been developed separately. These regulations provide the minimum requirements for subsea capping stacks in terms of their design, maintenance, and testing procedures to verify that the subsea capping stack is ready for use during an emergency scenario.

The recommended regulations provide the minimum requirements for subsea capping stacks. These regulations have been developed with the goal to be as generic as possible and allow for future development and innovation.

The recommended subsea capping stack CFR is divided into three sections:

1. Definition and References
2. Documentation to be submitted as part of the APD
3. Subsea Capping Stack System Requirements

Table 12.4, Table 12.5, and Table 12.6 provide the three sections of the recommended CFRs for subsea capping stacks.

Table 12.4: Subsea Capping Stack CFR – Definition and References

Subpart A – General
§250.105 Definitions *Subsea capping stack system* means any mechanical device that may be installed onto a subsea well with the primary purpose of shutting in a flowing well through mechanical isolation after a blowout has occurred. The device may be deployed from the surface and attached to a well subsequent to a blowout event and may serve as a mechanical connection point to facilitate: (1) The controlled flow of fluids originating within the well to a surface containment system for collection and disposal; and (2) The pumping of kill fluid into the well.
§250.198 Documents incorporated by reference. API RP 17H, Remotely Operated Tools and Interfaces on Subsea Production Systems, Second Edition, June 2013; Errata January 2014; incorporated by reference at §250.480(l).

Table 12.5: Subsea Capping Stack CFR – Documentation Required as Part of APD

Subpart D – Oil and Gas Drilling Operations

Applying for a Permit to Drill

30 CFR 250.419 What must I include in the subsea capping stack system descriptions?

Plan as used in §250.419 is defined as an approved plan or approved permit which contains information related to subsea capping stack systems, capabilities, and/or well data that is specific to well subsea capping stack interface.

You must include the following:

(a) Proof of access to a suitable subsea capping stack system;

(b) A Plan for mobilization of the subsea capping stack system to the incident location within a reasonable time predetermined by the Regional Director;

(c) A description of the subsea capping stack system and system components, including pressure ratings of subsea capping stack equipment;

(d) A schematic drawing of the subsea capping stack equipment that shows:

- (1) The inside diameter(s) of the subsea capping stack;
- (2) The number and size of all outlets and inlets;
- (3) The number, types, locations, and working pressure ratings of all closure devices;
- (4) The outlet bore(s) connection types, sizes, and working pressure ratings;
- (5) The lower interface connection type, size, and working pressure rating; and
- (6) The pressure monitoring and chemical injection port location(s).

(e) Proof that:

- (1) The subsea capping stack is suitable for use based on the Plan;
- (2) The subsea capping stack is capable of interfacing with specified wellhead and rig BOP systems; and
- (3) The subsea capping stack will operate in the conditions in which it will be used;

Amend §250.410(a) and §250.411(h) as follows:

§250.410 How do I obtain approval to drill a well?

(a) Submit the information required by §§250.411 through 250.419;

Add an additional row to the table in 30 CFR 250.411 as follows:

§250.411 What information must I submit with my application?

(h) Subsea capping stack system requirements . . . §250.419

Table 12.6: Draft CFR – Subsea Capping Stack System Requirements

Subpart D – Oil and Gas Drilling Operations

Subsea Capping Stack System Requirements

30 CFR 250.480 What are the subsea capping stack system requirements?

Plan as used in §250.480 is defined as an approved plan or approved permit which contains information related to subsea capping stack systems, capabilities, and/or well data that is specific to well subsea capping stack interface.

(a) The working pressure rating of each subsea capping stack component exposed to wellbore pressure must exceed the maximum anticipated wellhead pressure (MAWHP).

(b) The subsea capping stack system must have primary bore closure device(s). The closure device(s) must be located above the diverter.

(c) The subsea capping stack system must contain one or more outlets for diverting flow from and/or pumping kill fluid into the primary bore. Diverter outlet(s) must be located below the primary bore closure device(s).

(d) Each diverter path must have a closure device(s) between the outlet and primary bore.

(e) The diverter outlet(s) may be equipped with:

   (1) A subsea connector that is capable of installation or removal by an ROV;
   (2) An interface compatible with a designated containment system; and
   (3) An interface that is compatible for well kill operations.

(f) The subsea capping stack system must have a means of injecting chemicals below the diverter outlet(s). The location of the chemical injection may alternately be located below the outermost mechanical isolation device in the primary bore and each diverter outlet(s). The chemical injection path(s) must have a closure device located between the chemical injection inlet and the path(s) intersection with the primary bore.

(g) The subsea capping stack system must be capable of monitoring the primary bore pressure below each closure device.

(h) The subsea capping stack system must have a connector assembly that is compatible with the interfaces identified in the Plan. The connector must:

   (1) Interface with the incident well;
   (2) Accommodate various space-out requirements;
   (3) Remain latched if there is a loss of control line pressure; and
   (4) Be capable of providing for hydrate mitigation or remediation within the latch assembly.

Subpart D – Oil and Gas Drilling Operations Subsea Capping Stack System Requirements
(i) If the subsea capping stack system has a choke assembly, it must be suitable for the: (1) Rated working pressure or MAWHP; (2) Anticipated methods of well control; and (3) Operating environment. (j) If a subsea accumulator system is used to actuate closure devices, the system must: (1) Provide 1.25 times the volume of fluid capacity necessary to close and hold closed all hydraulic actuated closure devices; and (2) Perform at operating water depth, with a minimum pressure of 200 psi above the pre-charge pressure without assistance from a charging system. (k) If an external pressure cap is included in the system for installation onto the subsea capping stack primary bore, the cap must: (1) Be deployable on wire; (2) Be ROV operable; and (3) Provide pressure monitoring capability below the external pressure cap. (l) All ROV hydraulic or mechanical interfaces must conform to API RP 17H, Remotely Operated Tools and Interfaces on Subsea Production Systems (incorporated by reference as specified in §250.198). (m) All subsea capping stack system control panels must be clearly labeled. (n) The subsea capping stack must be capable of deploying either on drill pipe or wire. (o) You must provide evidence that shows the suitability of the subsea capping stack system and components for the service temperature range. (p) In areas subject to subfreezing conditions, you must provide evidence that the subsea capping stack systems, components, and other associated equipment and materials are suitable for operating under such conditions. (q) The BSEE District Manager may approve exceptions to subsea capping stack requirements.

Subpart D – Oil and Gas Drilling Operations

Subsea Capping Stack System Requirements

30 CFR 250.481 What are the subsea capping stack system maintenance, inspection, and preservation requirements?

(a) You must maintain, inspect, and preserve your subsea capping stack system to ensure that the equipment functions properly and that the system is ready for mobilization at any time with no need for additional maintenance or repair.

(b) The BSEE District Manager must approve the subsea capping stack maintenance, inspections, and preservation procedures.

(c) You must ensure that an official representative of BSEE will have access to the location to witness any maintenance, inspection, or preservation, and verify that this information is submitted to BSEE. Prior to any subsea capping stack maintenance, inspections, or preservation activities, you must notify the BSEE District Manager at least 72 hours in advance.

(d) You must document and record the results of your subsea capping stack inspections and maintenance actions and make the records available to BSEE upon request.

(e) You must maintain your records as specified in §250.484.

30 CFR 250.482 What are the subsea capping stack pressure test requirements?

(a) You must pressure test your subsea capping stack system to ensure that the equipment functions properly and that the system is ready for mobilization at any time with no need for additional maintenance or repair. Required pressure test frequencies are as follows:

(1) The subsea capping stack assembly must be pressure tested on a bi-annual basis, but no greater than 210 days between testing activities;

(2) Subsea capping stack closure device(s) must be individually pressure tested a minimum of once per year, but no greater than 379 days between testing activities; and

(3) Subsea capping stack component(s) that are affected following the disconnection or repair of any well-pressure containment seal must be pressure tested after repair is completed.

(b) You must conduct each individual pressure test as a hydrostatic test and hold pressure long enough to demonstrate that the tested assembly or component(s) can hold the required pressure. Required test pressures and durations are as follows:

(1) *Low pressure test.* All low pressure tests must be between 250 and 350 psi. Any initial pressure above 350 psi must be bled back to a pressure between 250 and 350 psi before starting the test.

Subpart D – Oil and Gas Drilling Operations

Subsea Capping Stack System Requirements

If the initial pressure exceeds 500 psi, you must bleed back to zero and re-initiate the test;

(2) *High pressure test.* The high pressure test must equal the rated working pressure of the equipment or be 500 psi greater than your calculated maximum anticipated wellhead pressure (MAWHP); and

(3) *Duration of pressure test.* Each test must hold the required pressure for 5 minutes. If the equipment does not hold the required pressure during a test, you must correct the problem and retest the affected component(s).

(c) You must record test pressures on pressure charts or a digital recorder.

(d) The BSEE District Manager must approve the subsea capping stack system pressure test procedures in advance of the testing.

(e) You must ensure that an official representative of BSEE will have access to the location to witness any pressure testing and verify information that is submitted to BSEE. You must notify the BSEE District Manager at least 72 hours in advance of any subsea capping stack pressure testing.

(f) You must document and record the successful results of your subsea capping stack pressure testing and make the records available to BSEE upon request.

(g) You must maintain your records as specified in §250.484.

30 CFR 250.483 What additional subsea capping stack system test must I perform?

(a) You must function test all subsea capping stack closure devices on a quarterly basis (not to exceed 104 days) from the last function test;

(b) You must test all subsea capping stack ROV controlled functions (§250.480[l]) on your subsea capping stack system on an annual basis, to verify interface compatibility between the ROV tool(s) and subsea capping stack control interface(s);

(c) You must document and record the successful results of your subsea capping stack testing and make the records available to BSEE upon request; and

(d) You must maintain your records as specified in §250.484.

Subpart D – Oil and Gas Drilling Operations Subsea Capping Stack System Requirements
30 CFR 250.484 What are the recordkeeping requirements for subsea capping stack system tests? You must record the time, date, and results of all maintenance, inspection, preservation, and testing activities conducted on the subsea capping stack system. In addition, you must: (a) Identify any problems or irregularities observed during system maintenance, inspection, preservation, and testing and record the actions taken to remedy the problems or irregularities; (b) Document the sequential order of subsea capping stack closure device actuation and pressure testing durations and record the actuation times for closure device(s); (c) Require your onsite representative to sign and date all reports and successful test charts and reports as correct; and (d) Retain all records, including pressure charts or digital records, maintenance reports, inspection reports, test reports, and referenced documents pertaining to tests, actuations, and inspections at the subsea capping stack system for a period of 5 years.
30 CFR 250.485 What are the subsea capping stack personnel requirements? You must: (a) Ensure that personnel who are authorized to operate subsea capping stack equipment at the surface are trained on the specific subsea capping stack systems and controls. (b) Ensure that personnel who are authorized to operate subsea capping stack equipment subsea are trained on the specific ROV system to be used and have been familiarized with subsea capping stack applications and controls.

12.4 Discussion – Recommended Subsea Capping Stack CFR

During a well control scenario, a variety of source control and containment equipment may be required, depending on the condition of the incident well. The equipment may include debris removal tools, dispersant systems, a subsea capping stack, and a containment system (flowlines, risers, manifolds, capture vessels, support vessels). This study is limited to subsea capping stacks and focuses on the design, testing, inspection, and maintenance requirements of subsea capping stacks.

A definition of the subsea capping stack system is provided in §250.105. Depending on the conditions of the well (cap only or cap and flow), the subsea capping stack may need to be connected to a surface containment system and be capable of pumping kill fluid into the well. The subsea capping stack system includes the auxiliary equipment such as the subsea accumulators and hot stabs. WGK has added API 17H as a reference in §250.198.

'Plan,' as it is defined in §250.419 and §250.480, can be any document that is approved by BSEE and includes information related to subsea capping stack systems, their capabilities, and data that is specific to the well capping interface. Currently, the subsea capping stack information being submitted to BSEE is a part of documents such as the Regional Containment Demonstration (RCD)[23], Well Containment Screening Tool Plus (WCST+), and the Well Containment Plan, depending on the Operator.

The RCD, which is updated every two years, serves as a pre-planned strategy for containment and a protocol for managing an emergency response. The WCST+ is submitted with the individual APD or Application for Permit to Modify (APM) and includes the following:

1. Copy of Operator's RCD approval letter
2. Compliance statement signed by an authorized company official
3. The WCST+, including fluid gradient and broaching analysis (if required)
4. Relief Well Plan
5. Cap and flow information (if required)
6. Rig-specific data, including the subsea capping stack connection information and subsea capping stack deployment procedures for the manual disconnect of the LMRP from the BOP or the BOP from the wellhead.
7. Acknowledgement that the Operator's well containment capabilities have not been reduced since approval of the RCD and no major changes have been made.

To avoid any confusion, the generic term 'Plan' is used in the CFR.

Section 250.419 provides details of the subsea capping stack information that must be submitted to BSEE along with the APD for obtaining a permit to drill. If the incident well cannot be completely shut in because of the pressure integrity of the wellbore, additional documentation showing access to a suitable containment system that is ready to respond in an emergency scenario will be submitted.

[23] The purpose of the RCD is to provide the BSEE with the detailed guidelines, processes, and procedures needed to contain a hydrocarbon release from a GOM deep water well that has been drilled using subsea BOPs or surface BOPs on floating facilities.

Maximum anticipated wellhead pressure (MAWHP) is the highest pressure predicted to be encountered at the wellhead in a subsea well. Section 250.480 provides the minimum subsea capping stack system requirements (refer to Table 12.6).

The subsea capping stack system components that are exposed to wellbore pressure must be rated to a working pressure greater than the MAWHP (§250.480[a]) and the temperature rating suitable for the service temperature range (§250.480[o]).

The subsea capping stack must have a primary bore, one or more diverter outlets, and a means to inject chemicals. The primary bore must have a closure device above the diverter. The diverter paths must have closure devices between the outlet and the primary bore. Depending on the well conditions, the diverter path may be equipped with choke valves or an interface that is compatible with the designated containment system. The subsea connectors must be ROV operable for the installation or removal of equipment at the diverter outlets.

The lower connector must be compatible with the identified interfaces (wellhead or BOP). The connector must accommodate space-out requirements and remain latched under loss of control line pressure. The connector must also have hydrate mitigation capability within the latch assembly. All ROV and hydraulic interfaces must conform to API 17H, and the control panels must be clearly labeled.

If a subsea accumulator is used, it must provide at least 1.25 times the volume of fluid necessary to close all hydraulically actuated closure devices. If an external pressure cap is used, it must be ROV operable and have pressure monitoring capability below the external pressure cap.

The subsea capping stack must be deployable by drill pipe or wire. For subfreezing conditions such as the Arctic, the Operator must show evidence that the subsea capping stack system is designed to operate under such conditions.

Section 250.481 states that the District Manager must approve subsea capping stack maintenance, inspection, and preservation procedures. The District Manager must be notified at least 72 hours in advance and must have access for the official BSEE representative to witness any maintenance, inspection, or preservation activities. The results of the inspections and maintenance must be recorded and made available to BSEE upon request.

Section 250.482 provides the pressure test requirements. The pressure tests must be conducted bi-annually with no more than 210 days between testing activities. In accordance with API 17W, the subsea capping stack is tested to a low pressure of 250 psi to 350 psi. The high pressure tests are conducted to the rated working pressure of the equipment or 500 psi greater than calculated MAWHP. To ensure that the subsea capping stack can hold pressure, the duration of the pressure test must be a minimum of 5 minutes.

Section 250.483 states that the function testing must be conducted on a quarterly basis, not to exceed 104 days from the last function test. All ROV-controlled functions must be tested on an annual basis. The results of the tests must be recorded and made available to BSEE upon request.

Section 250.484 provides the recordkeeping requirements for all the maintenance, inspection, preservation, and testing activities conducted on the subsea capping system.

Section 250.485 provides the subsea capping stack personnel requirements at both the yard and subsea.

13.0 Recommended Potential Incident of Noncompliance and Guideline List for Subsea Capping Stacks

13.1 Introduction

The OCS Lands Act authorizes and requires BSEE to provide an annual scheduled inspection and a periodic unscheduled (unannounced) inspection of all oil and gas operations on the OCS. The annual inspection examines all safety equipment that is designed to prevent blowouts, fires, spills, or other major accidents.

The Potential Incident of Noncompliance (PINC) and Guideline List is the checklist of items that BSEE inspects to pursue safe operations on the OCS. WGK has developed the subsea capping stack PINC List based on the recommended subsea capping stack CFRs in Section 12.0. The well containment consortiums and subsea capping stack Manufacturers have provided feedback on the PINC List to ensure that it complies with the current regulations in place (CFRs, NTLs) and covers all the aspects of testing, maintenance, inspection, and preservation requirements.

This section provides a set of usable PINC and Guidelines that have been prepared in accordance with the format included in the National PINC Guideline List. Agency inspectors both in the field and at onshore support bases and manufacturing establishments can use these PINC. In addition, WGK has made a recommendation regarding the location of the subsea capping stack PINC List in the National PINC Guideline List.

13.2 Recommended Location for Subsea Capping Stack PINC Guidelines

The PINC Guideline Lists are available on the BSEE webpage (http://www.bsee.gov/Inspection-and-Enforcement/Enforcement-Programs/Potential-Incident-of-Noncompliance---PINC/). These Guideline Lists are mainly categorized into Office PINC List and Field PINC List. The goal of the Office PINC List is to verify that the Operator has submitted all the required documentation with detailed procedures. The Field PINC List provides guidelines that BSEE personnel can use to inspect the equipment both in the field and at onshore support bases. The field PINCs are grouped into various sections, based on the operation (such as drilling, well completion, well workover) [40].

Similar to the subsea capping stack CFR recommendations, WGK also recommends that the subsea capping stack PINC List be added to the drilling PINCs. Table 13.1 shows the available PINCs on the BSEE website and the recommended location for the subsea capping stack PINC.

The Drilling PINCs have several sub-sections, and WGK proposes that two sub-sections be included for subsea capping stacks, as shown in Table 13.2.

The two recommended subsea capping stack sections are:

- Subsea Capping Stack Systems and Components
- Subsea Capping Stack Tests, Inspections, and Maintenance

Table 13.1: Available PINC Guidelines and Recommended Location for Subsea Capping Stack PINC [40]

- Office PINC List
- Field PINC List
  - Introduction
  - PINC List Revision Records
  - General PINCs
  - Pollution PINCs
  - **Drilling PINCs** (Recommended Location for Subsea Capping Stack PINC List)
  - Well-Completion PINCs
  - Well-Workover PINCs
  - Decommissioning PINCs
  - Production PINCs
  - Pipelines PINCs
  - Measurements and Site Security PINCs
  - Hydrogen Sulfide PINCs
  - Crane PINCs
  - Electrical PINCs
  - Personal Safety (USCG) PINCs
  - Appendices

Table 13.2: Recommended Location Under Drilling PINCs [40]

Drilling Operation Guidelines		
Available PINCs	Traveling Block	D-100 thru D-101
	Directional Survey	D-110 thru D-113
	Moving Drilling Rigs	D-120 thru D-121
	ESD System	D-130
	Casing Program	D-150 thru D-179
	BOP Systems and Components	D-200 thru D-227
	Surface BOP System	D-231 thru D-232
	Subsea BOP Systems	D-240 thru D-249
	BOP Tests, Actuators, Inspections, and Maintenance	D-250 thru D-269
	Surface BOP Tests	D-270 thru D-274
	Subsea BOP Tests	D-281 thru D-285
	Well-Control Drills	D-290 thru D-292
	Diverter Systems	D-300 thru D-314
	Surface Diverter Systems	D-315 thru D-334
	Drilling Fluid Program	D-400 thru D-416
	Classified Drilling Fluid-Handling Areas	D-421 thru D-429
	Securing of Wells	D-440
	Supervision, Surveillance, and Training	D-450 thru D-453
	Applications for Permit to Drill	D-460 thru D-463
	BOP Systems Maintenance/Inspection/Certification	D-500 thru D-504
	Subsea BOP System	D-600 thru D-604
	Stump Test	D-610 thru D-611
	Initial Installation Test	D-612 thru D-613
Recommended PINCs	**Subsea Capping Stack System and Components**	**D-700 thru D-715**
	Subsea Capping Stack Tests, Inspections and Maintenance	**D-720 thru D-733**

13.3 PINC Format and Description

This section provides the National PINC Guideline List format and the description of each term. Table 13.3 provides the format of the National PINC List.

Table 13.3: National PINC Guideline List Format [40]

[PINC NUMBER]	**[PINC STATEMENT]** **Authority: 30 CFR 250.XXX** **Enforcement Action: [W/C/S]** **DEFINITIONS**: [Definitions of terms used in the PINC to be provided here.] **INSPECTION PROCEDURE:** [Detailed guidelines to be used by BSEE personnel to ensure that the stated requirement is met must be provided here.] **IF NONCOMPLIANCE EXISTS:** [Describe the specific enforcement actions to be taken for each identified violation.] **INSPECTION COUNT/INC COUNT:** [Describe number of items checked to be entered on the inspection form.]

A description of each of the items in the PINC format follows:

- **PINC NUMBER**: A unique identifier for the specific requirement
- **PINC STATEMENT**: The clear and concise description of the requirement
- **AUTHORITY**: The regulatory authority as found in the Code of Federal Regulations
- **ENFORCEMENT ACTION**: This is the enforcement action(s) that BSEE must take for an identified violation(s) of the regulations. Enforcement action(s) may result in a complete facility shut-in (S), a component shut-in (C), or a warning (W).
- **DEFINITION**: Definition(s) of the term(s) used in the PINC
- **INSPECTION PROCEDURE**: Preferred, detailed guidelines to be used by BSEE personnel to ensure that the stated requirement is met. However, the guidelines in this document are to be considered the preferable method of implementing the enforcement of each PINC and are not intended as a directive or to supersede the regulatory language in the CFR.
- **IF NONCOMPLIANCE EXISTS**: Describes the specific enforcement action to be taken for each identified violation and the severity level of each violation of the regulations. Examples:
  - Issue a warning (**W**) incident of noncompliance when the situation poses no immediate danger to personnel or equipment.
  - Issue a component (**C**) incident of noncompliance for a specific piece of equipment or location when it is determined to be part of an unsafe situation or it poses an immediate danger to personnel or other equipment, and it can be shut in without affecting the overall safety of the facility.

- Issue a structure (**S**) incident of noncompliance when the unsafe situation poses an immediate danger to the entire facility or personnel, and the specific piece of equipment or location cannot be shut in without affecting the overall safety of the facility.

- **INSPECTION COUNT**: Describes the number of items checked to be entered on the inspection form. An Incident of Noncompliance (INC) must be issued to document any negative (no) answer to a PINC statement.
- **INC COUNT**: Dictates the specific number of incident(s) of noncompliance to be issued for identified violation(s) of the regulations.

13.4 Recommended Subsea Capping Stack PINC List

The subsea capping stack PINC Lists have been drafted in a format that is similar to the currently available inspection criteria in the National PINC Guideline List. WGK recommends that the subsea capping stack PINCs be divided into two sections, as listed in Table 13.2.

The PINC Lists have been drafted so that they are as generic as possible and allow for future development and innovation. The two sections of subsea capping stack PINCs are listed in Table 13.4 and Table 13.5.

Table 13.4: PINC Guideline List – Subsea Capping Stack Systems and Components

SUBSEA CAPPING STACK SYSTEMS AND COMPONENTS	
DEFINITION: *Plan* as used in PINC D-700 thru D-715 is defined as an approved plan or approved permit which contains information related to subsea capping stack systems, capabilities, and or well data specific to well subsea capping stack interface.	
D-700	**DOES THE WORKING PRESSURE RATING OF ALL SUBSEA CAPPING STACK SYSTEMS AND COMPONENTS EXCEED THE RATED WORKING PRESSURE OR MAXIMUM ANTICIPATED WELLHEAD PRESSURE (MAWHP) IDENTIFIED IN THE PLAN?** **Authority: 30 CFR 250.480(a)** **Enforcement Action: C** **INSPECTION PROCEDURE:** 1. Check the Plan for verification of MAWHP of subsea capping stack system. 2. Verify that working pressure of subsea capping stack components exposed to MAWHP exceed the MAWHP. **IF NONCOMPLIANCE EXISTS:**

	Issue a component shut-in (**C**) INC if the working pressure rating of subsea capping stack component(s) does not exceed the MAWHP. **INSPECTION COUNT/INC COUNT:** Enter one item checked/issue one INC for each subsea capping stack component inspected.
D-701	**IS THE SERVICE TEMPERATURE RANGE OF ALL SUBSEA CAPPING STACK SYSTEMS AND COMPONENTS SUITABLE FOR APPLICATION AS IDENTIFIED IN THE PLAN?** **Authority: 30 CFR 250.480(o)** **Enforcement Action: C** **INSPECTION PROCEDURE:** Check records and verify evidence that the subsea capping stack system and components are suitable for the range of temperatures in which they must operate. **IF NONCOMPLIANCE EXISTS:** Issue a component shut-in (**C**) INC if the service temperature range does not meet the requirements of the Plan. **INSPECTION COUNT/INC COUNT:** Enter one item checked/issue one INC for each subsea capping stack component inspected.
D-702	**IS THE PRIMARY BORE EQUIPPED WITH CLOSURE DEVICE(S)?** **Authority: 30 CFR 250.480(b)** **Enforcement Action: C** **INSPECTION PROCEDURE:** 1. Visually inspect primary bore to determine whether it is equipped with closure device(s). 2. Verify that the closure device is located above the diverter(s). **IF NONCOMPLIANCE EXISTS:** Issue a component shut-in (**C**) INC if the primary bore does not contain closure device(s) or the closure device is below the diverter. **INSPECTION COUNT/INC COUNT:** Enter one item checked/issue one INC for each subsea capping stack system inspected.
D-703	**IS DIVERTER CAPABILITY PROVIDED?** **Authority: 30 CFR 250.480(c)** **Enforcement Action: C** **INSPECTION PROCEDURE:** 1. Visually confirm diverter capability. 2. Verify that diverter(s) are located below the primary bore closure device.

	IF NONCOMPLIANCE EXISTS: Issue a component shut-in (**C**) INC if the subsea capping stack system does not have diverter capability. **INSPECTION COUNT/INC COUNT:** Enter one item checked/issue one INC for each subsea capping stack system inspected.
D-704	**IS EACH DIVERTER PATH EQUIPPED WITH A CLOSURE DEVICE(S) BETWEEN THE OUTLET AND THE PRIMARY BORE?** **Authority: 30 CFR 250.480(d)** **Enforcement Action: C** **INSPECTION PROCEDURE:** Visually inspect each diverter path to determine whether they are equipped with at least one closure device. **IF NONCOMPLIANCE EXISTS:** Issue a component shut-in (**C**) INC if the diverter path(s) are not equipped with at least one closure device. **INSPECTION COUNT/INC COUNT:** Enter one item checked/issue one INC for each diverter path inspected.
D-705	**IS CHEMICAL INJECTION CAPABILITY PROVIDED?** **Authority: 30 CFR 250.480(f)** **Enforcement Action: W** **INSPECTION PROCEDURE:** 1. Visually inspect the subsea capping stack to determine whether a minimum of one chemical injection path is present below the diverter outlet(s). 2. Alternatively, chemical injection may be provided below the outermost closure device in the primary bore and each diverter outlet(s). **IF NONCOMPLIANCE EXISTS:** Issue a warning (**W**) INC if no chemical injection capability exists. **INSPECTION COUNT/INC COUNT:** Enter one item checked/issue one INC for each subsea capping stack system inspected.
D-706	**IS EACH CHEMICAL INJECTION PATH EQUIPPED WITH ISOLATION DEVICE(S)?** **Authority: 30 CFR 250.480(f)** **Enforcement Action: C** **INSPECTION PROCEDURE:** Visually inspect each chemical injection path to determine whether they are equipped with at least one isolation device between chemical injection port and the

	primary bore. **IF NONCOMPLIANCE EXISTS:** Issue a component shut-in (**C**) INC if the chemical injection path(s) are not equipped with at least one isolation device. **INSPECTION COUNT/INC COUNT:** Enter one item checked/issue one INC for each chemical injection path inspected.
D-707	**IS THE SUBSEA CAPPING STACK EQUIPPED WITH THE CAPABILITY TO MONITOR PRIMARY BORE PRESSURE BELOW EACH CLOSURE DEVICE?** **Authority: 30 CFR 250.480(g)** **Enforcement Action: W** **INSPECTION PROCEDURE:** Visually inspect the subsea capping stack for capability to monitor pressure in the primary bore below each primary bore closure device. **IF NONCOMPLIANCE EXISTS:** Issue a warning (**W**) INC if no pressure monitor capability exists. **INSPECTION COUNT/INC COUNT:** Enter one item checked/issue one INC for each subsea capping stack system inspected.
D-708	**IS THE LOWER CONNECTOR ASSEMBLY INSTALLED ON THE SUBSEA CAPPING STACK SYSTEM?** **Authority: 30 CFR 250.480(h)** **Enforcement Action: C** **INSPECTION PROCEDURE:** 1. Verify that the subsea capping stack lower connector is compatible with the interfaces identified in the Plan. 2. Alternatively, if the lower connector does not match the interface identified in the Plan, confirm access to a suitable connector. 3. Verify that the lower connector remains latched when it is disconnected from hydraulics. **IF NONCOMPLIANCE EXISTS:** Issue a component shut-in (**C**) INC if the lower connector does not meet one or more of the requirements listed. **INSPECTION COUNT/INC COUNT:** Enter one item checked/issue one INC for each subsea capping stack system inspected.
D-709	**IS THE LOWER CONNECTOR ASSEMBLY CAPABLE OF HYDRATE MITIGATION?**

	Authority: 30 CFR 250.480(h)(5) **Enforcement Action: W** **INSPECTION PROCEDURE:** Verify hydrate mitigation capability within the latch assembly. **IF NONCOMPLIANCE EXISTS:** Issue a warning (**W**) INC if there is no hydrate mitigation capability for the lower connector. **INSPECTION COUNT/INC COUNT:** Enter one item checked/issue one INC for each subsea capping stack system inspected.
D-710	**IF THE SUBSEA CAPPING STACK IS EQUIPPED WITH CHOKE(S), ARE ALL COMPONENTS IN THE CHOKE ASSEMBLY SUITABLE FOR THE APPLICATION IN WHICH THOSE COMPONENTS WILL BE USED?** **Authority: 30 CFR 250.480(i)** **Enforcement Action: W** **INSPECTION PROCEDURE:** 1. Check the Plan for verification of the rated working pressure of choke(s) assembly. 2. Verify that the working pressure of the choke components exposed to the wellbore meet the rated working pressure or MAWHP. 3. Verify that the choke components are suitable for the application. **IF NONCOMPLIANCE EXISTS:** Issue a warning (**W**) INC for each choke component that does not have a working pressure exceeding the rated working pressure or for each choke component that is not suitable for the anticipated application. **INSPECTION COUNT/INC COUNT:** Enter one item checked/issue one INC for each subsea capping stack system inspected.
D-711	**IF THE IDENTIFIED ACCUMULATOR SYSTEM IS EQUIPPED WITH HYDRAULIC ACTUATED CLOSURE DEVICES, DOES IT PROVIDE SUFFICIENT CAPACITY?** **Authority: 30 CFR 250.480(j)** **Enforcement Action: C** **INSPECTION PROCEDURE:** 1. Verify that the accumulator system provides 1.25 times the volume of fluid capacity necessary to close and hold closed all hydraulic closure devices. 2. Verify that the accumulator activation system can operate at operating depth with a minimum of 200 psi above the pre-charge pressure without assistance from a charging system. 3. Check the accumulator system for leaks. **IF NONCOMPLIANCE EXISTS:**

	Issue a component shut-in (**C**) INC if the accumulator system does not meet one or more of the requirements listed above. **INSPECTION COUNT/INC COUNT:** Enter one item checked/issue one INC for each accumulator system inspected.
D-712	**IF THE SUBSEA CAPPING STACK PRIMARY BORE IS EQUIPPED WITH AN EXTERNAL PRESSURE CAP, IS IT SUITABLE FOR APPLICATION?** **Authority: 30 CFR 250.480(k)** **Enforcement Action: C** **INSPECTION PROCEDURE:** 1. Check records to verify that the external pressure cap installs on the subsea capping stack primary bore. 2. Verify that the external pressure cap can be deployed by wire. 3. Verify that the external pressure cap can be operated by ROV. 4. Verify that the external pressure cap has the ability to monitor the primary bore pressure. **IF NONCOMPLIANCE EXISTS:** Issue a component shut-in (**C**) INC if the external pressure cap does not meet one or more of the requirements listed. **INSPECTION COUNT/INC COUNT:** Enter one item checked/issue one INC for each subsea capping stack system inspected.
D-713	**IS THE SUBSEA CAPPING STACK EQUIPPED FOR ROV OPERATION?** **Authority: 30 CFR 250.480(l)** **Enforcement Action: C** **INSPECTION PROCEDURE:** 1. Check records to verify that the ROV is capable of cycling all ROV interfaces. 2. If conditions permit, witness: A. The ROV functions on the subsea capping stack during the test. B. The testing of at least one primary bore closure device, one diverter closure device, and actuation of the lower connector. C. The function testing of ROV hot stabs to determine whether they are capable of actuating a minimum of one primary bore closure device and one diverter closure device. **IF NONCOMPLIANCE EXISTS:** Issue a component shut-in (**C**) INC if the ROV function testing does not meet one or more of the requirements listed. **INSPECTION COUNT/INC COUNT:** Enter one item checked/issue one INC for each ROV inspected.

D-714	**IS THE SUBSEA CAPPING STACK EQUIPPED WITH A DEPLOYMENT SYSTEM THAT IS CONFIGURABLE FOR DEPLOYMENT ON DRILL PIPE OR WIRE?** **Authority: 30 CFR 250.480(n)** **Enforcement Action: W** **INSPECTION PROCEDURE:** Verify that the subsea capping stack is equipped for deployment on a drill pipe or wire. **IF NONCOMPLIANCE EXISTS:** Issue a warning (**W**) INC if both deployment methods are unavailable. **INSPECTION COUNT/INC COUNT:** Enter one item checked/issue one INC for each subsea capping stack system inspected.
D-715	**IF THEY ARE SUBJECTED TO SUBFREEZING CONDITIONS, ARE THE SUBSEA CAPPING STACK SYSTEM, COMPONENTS, OTHER ASSOCIATED EQUIPMENT, AND MATERIALS SUITABLE FOR OPERATION?** **Authority: 30 CFR 250.480(p)** **Enforcement Action: C** **INSPECTION PROCEDURE:** Check records and verify evidence that the subsea capping stack system, all components, other associated equipment, and materials are suitable for operating under subfreezing conditions. **IF NONCOMPLIANCE EXISTS:** Issue a component shut-in (**C**) INC if the requirements are not met. **INSPECTION COUNT/INC COUNT:** Enter one item checked/issue one INC for each subsea capping stack system inspected.

Table 13.5: PINC Guideline List – Subsea Capping Stack Testing, Inspection, and Maintenance

SUBSEA CAPPING STACK TESTING, INSPECTION, AND MAINTENANCE	
DEFINITION: *Plan* as used in PINC D-720 thru D-735 is defined as an approved plan or approved permit that contains information related to subsea capping stack systems, capabilities, and/or well data specific to well subsea capping stack interface.	
D-720	**DID THE OPERATOR PROVIDE THE BSEE REPRESENTATIVE ACCESS TO THE SUBSEA CAPPING STACK LOCATION TO WITNESS ANY TESTING OR INSPECTION?** **Authority: 30 CFR 250.481(c)** **Enforcement Action: W** **INSPECTION PROCEDURE:** Check records to verify whether the Operator notified the District Manager 72 hours in advance and provided access to the testing and inspection location. **IF NONCOMPLIANCE EXISTS:** Issue a warning (**W**) INC if the Operator did not notify the BSEE District Manager and provide access to the location to witness testing and inspection. **INSPECTION COUNT/INC COUNT:** Enter one item checked/issue one INC for each testing or inspection.
D-721	**HAVE ALL SUBSEA CAPPING STACK SYSTEM COMPONENTS BEEN SUCCESSFULLY TESTED TO A LOW PRESSURE OF 250 PSI TO 350 PSI PRIOR TO CONDUCTING HIGH PRESSURE TESTS?** **Authority: 30 CFR 250.482(b)(1)** **Enforcement Action: W** **Note:** If the initial pressure exceeds 500 psi, you must bleed back to zero and re-initiate the test. Any initial pressure greater than 350 psi must be bled back to a pressure between 250 and 350 psi before starting the test. **INSPECTION PROCEDURE:** 1. Verify that a low pressure test on subsea capping stack equipment was conducted prior to a high pressure test and that the test was conducted in accordance with specified requirements. 2. If inspection is being performed during commencement of testing of the subsea capping stack system, confirm compliance with low pressure testing requirements. **IF NONCOMPLIANCE EXISTS:** Issue a warning (**W**) INC if a low pressure test was not adequately conducted. Issue a warning (**W**) INC if records indicate that a low pressure test was not

	performed prior to a high pressure test and/or the test was not performed as required. **INSPECTION COUNT/INC COUNT:** Enter one item checked/issue one INC for each subsea capping stack component inspected.
D-722	**HAVE ALL SUBSEA CAPPING STACK SYSTEM COMPONENTS BEEN SUCCESSFULLY TESTED FOR HIGH PRESSURES?** **Authority: 30 CFR 250.482(b)(2)** **Enforcement Action: C** **INSPECTION PROCEDURE:** 1. Verify that all subsea capping stack components were tested to the rated working pressure of the equipment or were approved in the Plan. 2. If an inspection is performed during testing, confirm compliance by witnessing the pressure tests. **IF NONCOMPLIANCE EXISTS:** Issue a component shut-in (**C**) INC if the records indicate that the high pressure test was not adequately conducted to the rated working pressure of the equipment. Issue a component shut-in (**C**) INC if the required tests have not been conducted. **INSPECTION COUNT/INC COUNT:** Enter one item checked/issue one INC for each subsea capping stack system inspected.
D-723	**ARE AFFECTED SUBSEA CAPPING STACK COMPONENTS PRESSURE TESTED FOLLOWING DISCONNECTION OR REPAIR OF ANY PRESSURE CONTAINMENT BARRIER COMPONENT IN THE SUBSEA CAPPING STACK ASSEMBLY?** **Authority: 30 CFR 250.482(a)(3)** **Enforcement Action: C** **INSPECTION PROCEDURE:** If repairs require disconnection of the pressure seals, verify that the tests on affected equipment were conducted successfully. **IF NONCOMPLIANCE EXISTS:** Issue a component shut-in (**C**) INC if pressure seal tests were not conducted successfully following repairs. **INSPECTION COUNT/INC COUNT:** Enter one item checked/issue one INC for each subsea capping stack component inspected.
D-724	**ARE SUBSEA CAPPING STACK TEST PRESSURES RECORDED ON A**

	PRESSURE CHART OR DIGITAL RECORDER? **Authority: 30 CFR 250.482(c)** **Enforcement Action: C** **INSPECTION PROCEDURE:** Verify that the subsea capping stack test pressures have been recorded on a pressure chart or digital recorder. **IF NONCOMPLIANCE EXISTS:** Issue a component shut-in (**C**) INC if the test pressures have not been recorded on a pressure chart or digital recorder. **INSPECTION COUNT/INC COUNT:** Enter one item checked/issue one INC for each inspection.
D-725	**IS EACH SUBSEA CAPPING STACK COMPONENT TESTED FOR A MINIMUM OF 5 MINUTES TO DEMONSTRATE THAT THE COMPONENT IS HOLDING PRESSURE?** **Authority: 30 CFR 250.482(b)(3)** **Enforcement Action: C** **INSPECTION PROCEDURE:** Verify that each component held pressure for at least five minutes. **IF NONCOMPLIANCE EXISTS:** Issue a component shut-in (**C**) INC if the test duration requirement was not met. **INSPECTION COUNT/INC COUNT:** Enter one item checked/issue one INC for each inspection.
D-726	**DO THE RECORDED TEST RESULTS MATCH ACCORDING TO THE PLAN?** **Authority: 30 CFR 250.484(b)** **Enforcement Action: W** **INSPECTION PROCEDURE:** 1. Check the subsea capping stack test reports to verify that the sequential order of the subsea capping stack system testing and auxiliary system testing have been recorded. 2. Verify that the pressure and duration of each test have been recorded. 3. Verify that the closing times for the barrier system components have been recorded. **IF NONCOMPLIANCE EXISTS:** Issue a warning (**W**) INC if the documentation does not indicate the sequential order of the subsea capping stack system testing and auxiliary equipment testing and if the pressure, duration of each test, and closing times are not recorded. **INSPECTION COUNT/INC COUNT:** Enter one item checked/issue one INC for each inspection.

D-727	**ARE ALL RECORDS AVAILABLE, INCLUDING PRESSURE CHARTS, THIRD PARTY INSPECTOR'S REPORT, AND REFERENCED DOCUMENTS OF SUBSEA CAPPING STACK TESTS, ACTUATIONS, AND INSPECTIONS?** **Authority: 30 CFR 250.484(d)** **Enforcement Action: W** **INSPECTION PROCEDURE:** Verify that all records, including pressure charts, third party inspector's report, and referenced documents of subsea capping stack tests, actuations, and inspections are available. **IF NONCOMPLIANCE EXISTS:** Issue a warning (**W**) INC if any records of subsea capping stack tests, actuations, and inspections, including pressure charts, third party inspector's report, and referenced documents are not available. **INSPECTION COUNT/INC COUNT:** Enter one item checked/issue one INC for each inspection.
D-728	**ARE ALL SUBSEA CAPPING STACK SYSTEM PRESSURE TESTS AND ACTUATION TEST RECORDS RETAINED FOR A PERIOD OF FIVE YEARS?** **Authority: 30 CFR 250.484(d)** **Enforcement Action: W** **INSPECTION PROCEDURE:** Verify that all such records are available as required. **IF NONCOMPLIANCE EXISTS:** Issue a warning (**W**) INC if records are not available as required. **INSPECTION COUNT/INC COUNT:** Enter one item checked/issue one INC for each inspection.
D-729	**ARE SUBSEA CAPPING STACK CLOSURE DEVICES PRESSURE TESTED BI-ANNUALLY (NOT TO EXCEED 210 DAYS)?** **Authority: 30 CFR 250.482(a)(1)** **Enforcement Action: W** **INSPECTION PROCEDURE:** Verify that test records and charts indicate that pressure tests were performed as required. **IF NONCOMPLIANCE EXISTS:** Issue a warning (**W**) INC if the pressure test was not performed when required, but a subsequent pressure test was performed successfully. Issue a warning (**W**) INC if the pressure test was not performed when required, nor was a subsequent successful pressure test performed. **INSPECTION COUNT/INC COUNT:**

	Enter one item checked/issue one INC for each inspection.
D-730	**ARE SUBSEA CAPPING STACK CLOSURE DEVICES FUNCTION TESTED ON A QUARTERLY BASIS (NOT TO EXCEED 104 DAYS)?** **Authority: 30 CFR 250.483(a) Enforcement Action: W** **INSPECTION PROCEDURE:** Verify test records indicate that function tests were performed as required. **IF NONCOMPLIANCE EXISTS:** Issue a warning (**W**) INC if the test was not performed when required, but a subsequent test was performed successfully. Issue a warning (**W**) INC if the test was not performed when required, nor was a subsequent successful test performed. **INSPECTION COUNT/INC COUNT:** Enter one item checked/issue one INC for each inspection.
D-731	**ARE MANUFACTURERS' INSTALLATION, OPERATION, AND MAINTENANCE (IOM) MANUALS AVAILABLE FOR ALL SUBSEA CAPPING STACK EQUIPMENT?** **Authority: 30 CFR 250.484(d) Enforcement Action: W** **INSPECTION PROCEDURE:** Verify that Manufacturers' IOM manuals are available for all subsea capping stack equipment. **IF NONCOMPLIANCE EXISTS:** Issue a warning (**W**) INC if the Manufacturer's IOM manuals are not available for all subsea capping stack equipment. **INSPECTION COUNT/INC COUNT:** Enter one item checked/issue one INC for each inspection.
D-732	**DOES THE SUBSEA CAPPING STACK OWNER MAINTAIN COPIES OF EQUIPMENT MANUFACTURERS' PRODUCT ALERTS OR EQUIPMENT BULLETINS?** **Authority: 30 CFR 250.484 Enforcement Action: W** **INSPECTION PROCEDURE:** Verify that the Owner has copies of equipment Manufacturers' product alerts or equipment bulletins and that they are made readily available to BSEE upon request. **IF NONCOMPLIANCE EXISTS:** Issue a warning (**W**) INC if the Owner does not have copies of equipment Manufacturers' product alerts or equipment bulletins and they are not made available

	to BSEE upon request. **INSPECTION COUNT/INC COUNT:** Enter one item checked/issue one INC for each inspection.
D-733	**ARE ALL CONTROL PANELS OF THE SUBSEA CAPPING SYSTEM CLEARLY LABELED?** **Authority: 30 CFR 250.480(m)** **Enforcement Action: W** **INSPECTION PROCEDURE:** Verify that the Operator has clearly labeled all control panels for the subsea capping stack system. **Note:** Verify that the control panel is an accurate representation to properly indicate subsea capping stack system status. **IF NONCOMPLIANCE EXISTS:** Issue a warning (**W**) INC if the labels on the control panels of the subsea capping stack are not clear. **INSPECTION COUNT/INC COUNT:** Enter one item checked/issue one INC for each subsea capping stack system inspected.

13.5 Discussion – Subsea Capping Stack Inspection Criteria and PINC List

The PINC Guideline List that has been developed for subsea capping stacks is based on the recommended CFRs. The PINC number, its corresponding statement, and comments/justifications are provided for each item in Table 13.6 and Table 13.7.

Table 13.6: PINC Discussion – Subsea Capping Stack Systems and Components

PINC No.	PINC Statement	Justification/Comments
D-700	DOES THE WORKING PRESSURE RATING OF ALL SUBSEA CAPPING STACK SYSTEMS AND COMPONENTS EXCEED THE RATED WORKING PRESSURE OR MAXIMUM ANTICIPATED WELLHEAD PRESSURE (MAWHP) IDENTIFIED IN THE PLAN?	If the subsea capping stack does not meet the rated working pressure or MAWHP, it may not withstand the wellbore pressure and can fail. It is critical to ensure the rating of the subsea capping stack and components.
D-701	IS THE SERVICE TEMPERATURE RANGE OF ALL SUBSEA CAPPING STACK SYSTEMS AND COMPONENTS SUITABLE FOR APPLICATION AS IDENTIFIED IN THE PLAN?	If the service temperature of the subsea capping stack does not meet the temperature criteria identified in the Plan, it may not withstand the high temperatures and can fail. It is therefore critical to ensure that the identified subsea capping stack meets the temperature provided in the Plan.
D-702	IS THE PRIMARY BORE EQUIPPED WITH CLOSURE DEVICE(S)?	The primary bore must be equipped with a ram or gate valve to stop the flow through the primary bore.
D-703	IS DIVERTER CAPABILITY PROVIDED?	Diverters are required to divert the flow through them when the primary bore is closed. The flow through the diverters is controlled using the gate valve and choke.
D-704	IS EACH DIVERTER PATH EQUIPPED WITH A CLOSURE DEVICE(S) BETWEEN THE OUTLET AND THE PRIMARY BORE?	Each diverter path must have a closure device (usually a gate valve) to stop the flow through the diverter line.
D-705	IS CHEMICAL INJECTION CAPABILITY PROVIDED?	Chemical injection capability is required for dispersant injection and hydrate mitigation.
D-706	IS EACH CHEMICAL INJECTION PATH EQUIPPED WITH ISOLATION DEVICE(S)?	The chemical injection path must have closure devices (usually a gate valve) to control the flow.
D-707	IS THE SUBSEA CAPPING STACK EQUIPPED WITH THE CAPABILITY TO MONITOR PRIMARY BORE PRESSURE BELOW EACH CLOSURE DEVICE?	The pressure below each closure device must be monitored.
D-708	IS THE LOWER CONNECTOR ASSEMBLY INSTALLED ON THE SUBSEA CAPPING STACK SYSTEM?	Depending on the well, a suitable lower connector must be installed on the subsea capping stack system.

PINC No.	PINC Statement	Justification/Comments
D-709	IS THE LOWER CONNECTOR ASSEMBLY CAPABLE OF HYDRATE MITIGATION?	The lower connector must have capability to inject chemicals for hydrate remediation.
D-710	IF SUBSEA CAPPING STACK IS EQUIPPED WITH CHOKE(S), ARE ALL COMPONENTS IN THE CHOKE ASSEMBLY SUITABLE FOR THE APPLICATION IN WHICH THOSE COMPONENTS WILL BE USED?	If the diverter outlets are equipped with chokes, it must be verified that they are suitable for the application.
D-711	IF THE IDENTIFIED ACCUMULATOR SYSTEM IS EQUIPPED WITH HYDRAULIC ACTUATED CLOSURE DEVICES, DOES IT PROVIDE SUFFICIENT CAPACITY?	The subsea accumulator system must have sufficient hydraulic fluid to activate all hydraulic-actuated closure devices.
D-712	IF THE SUBSEA CAPPING STACK PRIMARY BORE IS EQUIPPED WITH AN EXTERNAL PRESSURE CAP, IS IT SUITABLE FOR APPLICATION?	It must be verified that the external pressure cap fits the subsea capping stack primary bore (top mandrel). The external pressure cap must be operable by ROV and have the ability to monitor pressure in the primary bore.
D-713	IS THE SUBSEA CAPPING STACK EQUIPED FOR ROV OPERATION?	The subsea capping stacks must be ROV operated and have control panels.
D-714	IS THE SUBSEA CAPPING STACK EQUIPED WITH A DEPLOYMENT SYSTEM THAT IS CONFIGURABLE FOR DEPLOYMENT ON DRILL PIPE OR WIRE?	The subsea capping stack must be capable of deploying by wire or drill pipe.
D-715	IF THEY ARE SUBJECTED TO SUBFREEZING CONDITIONS, ARE THE SUBSEA CAPPING STACK SYSTEM, COMPONENTS, OTHER ASSOCIATED EQUIPMENT, AND MATERIALS SUITABLE FOR OPERATION?	For subfreezing conditions (Arctic conditions), the subsea capping stack system, components, and materials must be suitable for operation.

Table 13.7: PINC Discussion – Subsea Capping Stack Testing, Inspection, and Maintenance

PINC No.	PINC Statement	Justification/Comments
D-720	DID THE OPERATOR PROVIDE THE BSEE REPRESENTATIVE ACCESS TO THE SUBSEA CAPPING STACK LOCATION TO WITNESS ANY TESTING OR INSPECTION?	The Operator must provide the BSEE representatives access to the subsea capping stack location to witness any tests or inspections.
D-721	HAVE ALL SUBSEA CAPPING STACK SYSTEM COMPONENTS BEEN SUCCESSFULLY TESTED TO A LOW PRESSURE OF 250 PSI TO 350 PSI PRIOR TO CONDUCTING HIGH PRESSURE TESTS?	Low pressure tests must be conducted periodically.
D-722	HAVE ALL SUBSEA CAPPING STACK SYSTEM COMPONENTS BEEN SUCCESSFULLY TESTED FOR HIGH PRESSURES?	High pressure tests must be conducted periodically.
D-723	ARE AFFECTED SUBSEA CAPPING STACK COMPONENTS PRESSURE TESTED FOLLOWING DISCONNECTION OR REPAIR OF ANY PRESSURE CONTAINMENT BARRIER COMPONENT IN THE SUBSEA CAPPING STACK ASSEMBLY?	Following disconnection or repair, all pressure bearing components must be tested to ensure that there are no leaks and the system can withhold pressure.
D-724	ARE SUBSEA CAPPING STACK TEST PRESSURES RECORDED ON A PRESSURE CHART OR DIGITAL RECORDER?	Pressure tests must be recorded.
D-725	IS EACH SUBSEA CAPPING STACK COMPONENT TESTED FOR A MINIMUM OF 5 MINUTES TO DEMONSTRATE THAT THE COMPONENT IS HOLDING PRESSURE?	Critical components must be pressure tested for a minimum of 5 minutes to confirm that they can withhold pressure.
D-726	DO THE RECORDED TEST RESULTS MATCH ACCORDING TO THE PLAN?	The results of tests must be recorded in a particular order as mentioned in the Plan.

PINC No.	PINC Statement	Justification/Comments
D-727	ARE ALL RECORDS AVAILABLE, INCLUDING PRESSURE CHARTS, THIRD PARTY INSPECTOR'S REPORT, AND REFERENCED DOCUMENTS OF SUBSEA CAPPING STACK TESTS, ACTUATIONS, AND INSPECTIONS?	All records must be stored and available when needed.
D-728	ARE ALL SUBSEA CAPPING STACK SYSTEM PRESSURE TESTS AND ACTUATION TEST RECORDS RETAINED FOR A PERIOD OF FIVE YEARS?	Test results and other documentation must be stored for a minimum of five years.
D-729	ARE SUBSEA CAPPING STACK CLOSURE DEVICES PRESSURE TESTED BI-ANNUALLY (NOT TO EXCEED 210 DAYS)?	Pressure testing is conducted bi-annually.
D-730	ARE SUBSEA CAPPING STACK CLOSURE DEVICES FUNCTION TESTED ON A QUARTERLY BASIS (NOT TO EXCEED 104 DAYS)?	Function testing is conducted quarterly.
D-731	ARE MANUFACTURERS' INSTALLATION, OPERATION, AND MAINTENANCE (IOM) MANUALS AVAILABLE FOR ALL SUBSEA CAPPING STACK EQUIPMENT?	IOM manuals must be available for all subsea capping stack equipment.
D-732	DOES THE SUBSEA CAPPING STACK OWNER MAINTAIN COPIES OF EQUIPMENT MANUFACTURERS' PRODUCT ALERTS OR EQUIPMENT BULLETINS?	The subsea capping stack Owner must maintain Manufacturers' product alerts and equipment bulletins.
D-733	ARE ALL CONTROL PANELS OF THE SUBSEA CAPPING SYSTEM CLEARLY LABELED?	Proper labeling of control panel equipment is critical, as the lack of proper labeling can create confusion for ROV pilots during emergency operations.

14.0 New Technologies and Future Developments for Subsea Capping Stacks

14.1 Introduction

This section provides details of the new technologies and planned future developments in the subsea capping stack industry.

14.2 Development of High Temperature and High Pressure Subsea Capping Stacks

The subsea capping stacks currently available in the industry are rated up to 15,000 psi and 350°F only. Some of the wells being drilled have pressures and temperatures greater than 15,000 psi and 350°F. Therefore, the subsea capping stack industry is working on developing new High Pressure and High Temperature (HPHT) subsea capping stacks.

Currently, Shell and MWCC are building two subsea capping stacks for the U.S. Gulf of Mexico (GOM):

- A subsea capping stack rated for 15,000 psi and 400°F
- A subsea capping stack rated for 20,000 psi and 350°F

The 15,000-psi 400°F subsea capping stack will be available in 2016, and the 20,000-psi 350°F subsea capping stack will be available in 2017. At the time this report was being prepared, no other part of the world had developed HPHT subsea capping stacks.

14.3 NWC-H Overshot Connector

The Seaboard™ NWC-H Overshot Connector, which Weir Oil & Gas has developed for offshore use, provides a quick response solution when the post-incident existing well infrastructure no longer offers a conventional point of connection. The NWC-H connector is attached to the bottom of the subsea capping stack. The location of the connection enables the connector to be installed directly over a producing well, and it attaches to the well casing. The connector features proprietary patent pending technology to ensure the protection of sealing mechanisms during installation. This connector is specifically designed to remediate critical failures using a safe and reliable method [41].

This connector is available in a variety of sizes to accommodate a wide range of casing sizes and pressures. The system, which can be placed on a barge, can be ready to go at moment’s notice. As of 2015, the casing size design range is 6-5/8 in. through 14 in. API 5CT casing for wellbore pressures up to 15,000 psi.

Figure 14.1 shows the NWC-H overshot connector, and Figure 14.2 shows the connector attached to a subsea capping stack to control a flowing well.

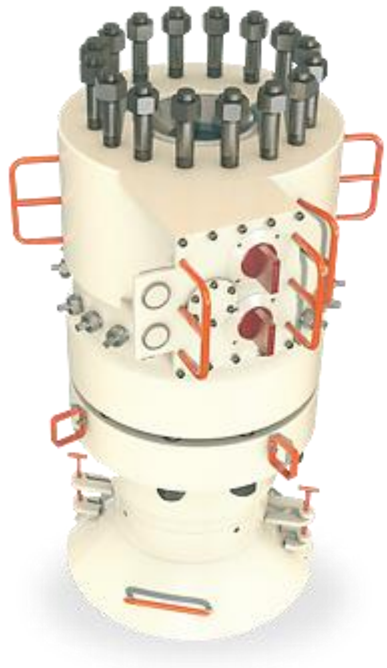


Figure 14.1: Seaboard™ NWC-H Overshot Connector

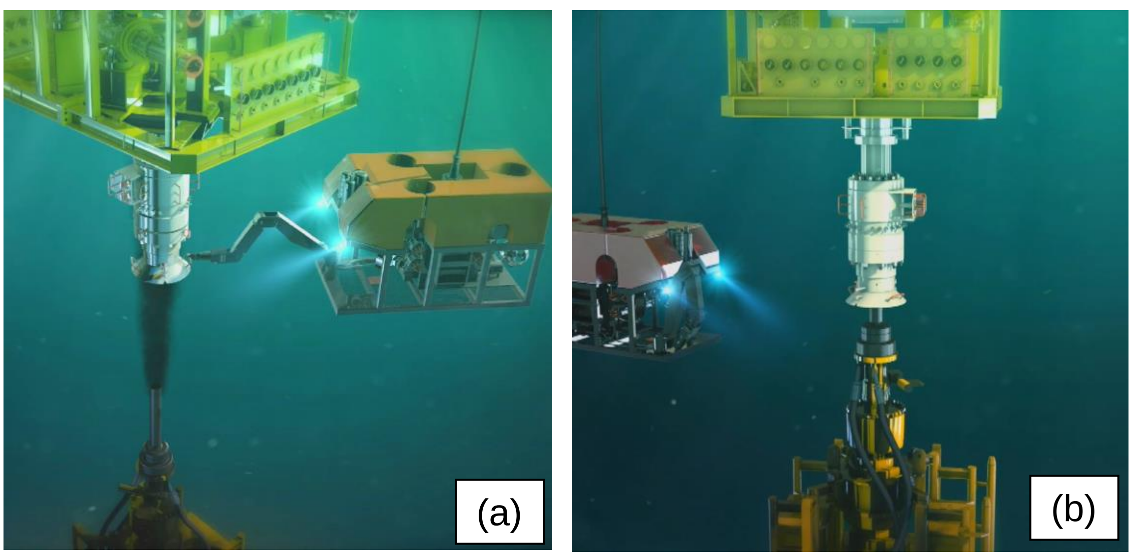


Figure 14.2: Schematic of Subsea Capping Stack with NWC-H Overshot Connector Being Installed on a Flowing Well

14.4 Improvements to Existing Subsea Capping Stacks

The subsea capping stacks that are currently available are being reviewed for any possible improvements in their capabilities, such as updating the temperature rating and providing chemical injection paths. MWCC is working on upgrading their 15,000-psi subsea capping stack from 250°F to 350°F.

14.5 Potential Technological Advancements for Subsea Capping Stacks

The industry continues its technological advancement toward satisfying the purpose(s) of subsea capping stacks in whole or in part. Advancement may be in the form of new, specific components or comprehensive systems. New technology developers may be supported by public-private partnerships, consortium collaborations, Joint Industry Partnerships (JIPs), or investor funding. A specific new potential technology advancement may only be in the conceptual or lab testing stage, and its Technology Readiness Level (TRL) may be low—in the range of TRL 1-4. New technologies also strive to reduce weight and size; deployment and operational complexity; and modularity for replacing, repairing, inspecting, testing, and maintaining components and systems.

A JIP composed of privately owned Bastion Technologies and the Research Partnership to Secure Energy for America (RPSEA)[24] is currently offering for development an example of a new potential technology set that relates to subsea capping stacks. These two entities are forming a JIP to build and test two very important ideas that RPSEA's Technical Advisory Committee (TAC) has chosen from its requests for projects, neither of which the Department of Energy (DOE) has funded.

The first technology, the 'IntrSeptr,' was conceptualized as an intelligent complementary riser post-BOP. Based on sensor data, the riser can be closed and then opened back up after any well control concerns have been addressed. The second technology, 'PYRO-Accumulator,' is a significant compact safety tool that can also create power from casing gas right off the wellhead. Bastion has stated that these new technologies are in TRL 1-3 with concept designs on paper, but they still require funding to advance to the prototype stage.

[24] RPSEA was primarily formed and supported by U.S. DOI Section 999 allotments, which are managed by the U.S. DOE, and private industry, public university, and organization membership funds. The DOE contracted RPSEA so that industry technology gaps, which further research may cover, but which industry alone was not expected to fund, would be identified and distilled into scopes of work. It was expected that potential qualified research organizations would be sought, bids would be reviewed, and the projects would be ranked for potential funding by the DOE. All of this would be accomplished with volunteer subject matter experts (SMEs) in their respective fields. The DOE chose the projects and funding levels for each program. RPSEA's primary contract with DOE will end September 30, 2015. Refer to www.rpsea.org.

15.0 Findings and Recommendations

15.1 Findings

1. The Macondo incident has led to a re-evaluation of deep water drilling procedures. Currently, most country regulators require oil companies to have access to and be able to deploy well containment equipment in response to a loss of well control incident. Regulators are issuing drilling permits only after ensuring that the oil companies have the equipment to respond to a well event.
2. Industry-owned cooperative consortiums (such as MWCC, HWCG, OSRL) have been formed to store and maintain the well containment equipment and be ready to respond to a loss of well control incident. With these consortiums, oil companies share the cost of equipment and resources.
3. The consortiums and organizations that provide containment equipment include:
    - MWCC, which owns three subsea capping stacks and one containment system. The subsea capping stacks, which are stored in Ingleside, Texas, serve the GOM.
    - HWCG, which contracts two subsea capping stacks and one containment system. One subsea capping stack is stored in Houston, Texas, and the other is in Ingleside, Texas. Both serve the GOM.
    - SWRP, which collaborates with OSRL and has four subsea capping stacks and a containment system. OSRL subsea capping stacks are stored at different locations around the world and serve worldwide, with the exception of the GOM.
    - WellCONTAINED, which owns two subsea capping stacks. One subsea capping stack is stored in Aberdeen, and the other is in Singapore. Both are available globally and can be transported by sea or air.
4. The subsea capping stacks from each company can be used by their member companies only. Non-members have no access to the subsea capping stacks. Only MWCC provides non-members access to its equipment on a per well basis.
5. Some major oil companies (for example, Shell and BP) are members of consortiums, but they also own subsea capping stacks. This provides redundancy and adds to the oil companies' global capabilities.

6. The available capping options for the International Regulators' Forum (IRF) countries are:
   - U.S. and U.K. have local consortiums and have containment equipment dedicated to their deep water drilling regions.
   - Australia does not have a local capping solution and depends on global subsea capping stacks (SWRP and WellCONTAINED). They have the Subsea First Response Toolkit (SFRT) that can clear the debris and prepare the incident wellsite for capping operation before the global subsea capping stack reaches the incident site.
   - Similar to Australia, Canada does not have a local capping system, but it does have the First Response Well Containment System, which can immediately respond to the well incident to clear the wellsite for capping installation. Canada depends on global subsea capping stacks.
   - Norway and Brazil do not have subsea capping stacks dedicated to their regions. However, these two countries house two of the four storage locations of SWRP subsea capping stacks. Therefore, these two countries have access to the subsea capping stacks.
   - Denmark, New Zealand, Mexico, and the Netherlands depend on the global capping solutions only.
7. Currently, no country has regulations in place related to subsea capping stacks. Regulators require oil companies to have access to containment equipment before they can obtain a permit to drill.
8. Except for the U.S. and the U.K., oil companies drilling in other regions are justifying their contingency plans with regulators by arranging access to global subsea capping stack systems (OSRL and WellCONTAINED) on a case-by-case basis.
9. The following are the major responses to the industry surveys:
   - Standardization of capping equipment is not recommended. Having multiple tools to perform the same operation can create redundancy and provide secondary options.
   - Mobilization and deployment of a subsea capping stack is challenging because of its large size and weight. The use of gate valves instead of BOP rams can be considered for smaller casing sizes. This can reduce the weight of the subsea capping stacks and avoid the need for having large Subsea Accumulator Module (SAM) units. For larger casing sizes, BOP rams may be needed, as gate valves are not available in larger sizes.

- For wellheads that are severely damaged, installing a subsea capping stack can be difficult or impossible. The industry suggests that adapter tools be developed to make a successful connection with a flowing well.
- API RP 17W [1] was not followed for the design of existing subsea capping stacks because they were built before API RP 17W came into existence. The newly designed subsea capping stacks follow API RP 17W guidelines.
- API RP 17W needs improvement in the area of High Pressure High Temperature (HPHT).

10. Most of the available subsea capping stacks are rated for a pressure of 15,000 psi and for temperatures up to 350°F. The industry is currently working on developing subsea capping stacks for HPHT conditions (20,000 psi and 400°F).

15.2 Recommendations

Based on the key findings in Section 15.1, the following are recommended for consideration:

1. Evaluate subsea capping stack components that can accommodate weight savings. This could be using gate valves instead of BOP rams for smaller bore sizes. The gate valves can provide the same pressure rating as BOP rams. The benefits associated with the use of gate valves include improved sealing reliability (metal-metal sealing surface), reduction in weight, and simplified operation avoiding the need for Subsea Accumulator Module (SAM) units.
2. Due to the geographic distances between subsea capping stack storage locations and potential incident sites, it is recommended that a specific subsea capping stack should be identified prior to the commencement of operations within each deep water drilling region and associated mobilization planning conducted to determine the estimated response time. This process would allow for the assessment of estimated response time to ensure that it is acceptable as well as identify areas for efficiency improvement related to deployment and installation
3. Develop subsea capping stacks for High Pressure High Temperature (HPHT) conditions. The consortium owners should consider procuring new HPHT subsea capping stacks or improving the capabilities of the existing ones, depending on the members' planned wells to which the consortium may need to respond. Trendsetter has been contracted by Shell to deliver a 400°F subsea capping stack in 2016 and by MWCC to deliver a 20,000 psi subsea capping stack by 2017.

4. Review other parts of SCCE (such as the containment system[25], debris removal, and dispersant equipment). Currently, there are no minimum requirements for the containment system and no consistency on what defines a containment system. There are different technologies and levels of containment system (interim versus long-term), depending on the capabilities. It must be noted that the absence of 'minimum requirements' or a definition of a containment system has allowed development (in the U.S. GOM at least) of two different, robust solutions. In addition, the interfaces between subsea capping stack and containment systems has not been standardized which could lead to delays in deployment and recovery operations should an incident occur.
5. Although BSEE currently using terminology such as 'Cap', 'Cap and Flow' and 'Source Control and Containment Equipment', it is highly recommended that this terminology be assessed and reviewed against terminology which is being standardized internationally. Some examples of major discrepancies include the U.S. term 'Cap and Contain' meaning installation and shut-in with a capping stack, while on the international front 'Capping' means installation and shut-in with a capping stack. In U.S. the term 'Cap and Flow' implies that a capping stack has been installed, but the well is being flowed to a surface vessel, whereas the term 'Containment' has the same meaning international.

[25] A containment system includes any system or component downstream of the subsea capping stack that directs flow.

16.0 References

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