

Cementing Shallow-water Flow Zones in Deepwater Wells

API RECOMMENDED PRACTICE 65-1
SECOND EDITION, JUNE 2018



AMERICAN PETROLEUM INSTITUTE

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Cementing Shallow-water Flow Zones in Deepwater Wells

1 Scope

1.1 Overview

This standard describes practices designed to prevent shallow-water flow (SWF) during and following the cementing of wells located in deepwater. It is the compilation of technology and practices developed and used by many operators around the world. Although most of the discussion in this standard is focused on SWF, shallow flows can be mixtures of water, gas, gas hydrates, and formation fines. There is no single method of preventing shallow-water flow, and many of the activities described may require customization to fit individual well conditions. While this standard is extensive, it is not meant to limit innovation and new technology.

The content of this document is not all inclusive, and guidance from other sources may apply. Note that this standard is not meant to be a stand-alone training manual or well design standard.

Although fairly comprehensive, there are still many details that are not discussed and that should be addressed when drilling and cementing wells in deepwater. It is meant to highlight key parameters for increasing the chance of successfully drilling and cementing casings where there is a risk of shallow-water flow and to discuss options that are available. More details can be gleaned from the references listed in the bibliography. Most of the information in this document is from U.S. Gulf of Mexico experience. The concepts can be applied in other deepwater environments with appropriate modifications. The user should consult experts within the industry for specific details of the cementing process relating to the technology being used by a specific company for a specific scenario. The construction of the casings through the SWF zones should be a team effort to be successful. All parties involved shall participate in the planning and execution of all phases of the process to ensure successful construction of the conductor and surface casings.

In this standard, where practical, U.S. customary units (USC) are included in parentheses for information. The units do not necessarily represent a direct conversion of metric units (SI) to USC units, or USC to SI. Consideration has been given to the precision of the instrument making the measurement. For example, thermometers are typically marked in one-degree increments; thus, temperature values have been rounded to the nearest degree.

1.2 Objective

The objective of this standard is to communicate methods to prevent shallow-water flows in the tophole sections of deepwater wells during and after cementing operations.

1.3 Conditions of Applicability

This document is applicable to the following well conditions:

- tophole section(s) of the well;
- shallow hazard assessment concludes a risk/potential for shallow flow.

This does not include isolating potential flow zones beyond the tophole section(s) of the well; see [API Standard 65-2](#).

1.4 Background

SWF are water flows from permeable formations at shallow depths below the mudline in wells drilled in deep ocean waters. The water flows can compromise the structural or hydraulic integrity, or both, of the

tophole section(s). The tophole section is a part of the well often drilled without a marine riser where drilling and cementing fluids exit the well annulus at the seafloor. SWF can occur in sections drilled with a riser where fluid returns are at the rig. Modes of failure include:

- poor isolation by cement resulting in casing buckling/shear;
- pressure communication to other shallow formations, causing them to be overpressured;
- disturbance of the seafloor due to breakthrough of the shallow flow to the mudline.

NOTE Such damage can result in the complete loss of drilling templates containing previously cased wells.

Flows from these shallow formations are typically a result of abnormally high pore pressure in under-compacted and usually unconsolidated sediments formed in a rapid depositional environment. Not all flows are the result of these naturally developed formation geopressures. Other causes for abnormal shallow pressures include hydraulic communication from deeper, higher-pressure formations, tectonic uplift, and induced storage during drilling, casing, and cementing operations.

Flow of sediments results in hole enlargement, which can increase the rate of flow and make it more difficult to control. The enlargement may also cause caving of formations above the flow interval. The flow of water and formation material from these zones can result in damage to the wells, including foundation failure, formation compaction, damaged casing (wear and buckling), re-entry and control problems, sea floor craters, mounds, and crevasses (R.M. Ostermeier et al. 2000, Eaton, L.F. 1999). Flow channels through or around the cement sheath may be formed as a result of one or more of the following:

- poorly designed or executed primary cementing;
- flow occurring due to dilution or channeling while the cement is being placed;
- flow occurring after the cement slurry is placed, but before it has attained a structure sufficient to prevent formation fluid flow, will create channels through which flow can continue;
- poor hole conditions.

Geopressure can be transmitted through channels in the cement sheath and, if trapped by a seal (mechanical isolation), can charge or fracture a formation of lower pressure or strength. If the fracture extends beyond the wellbore, it could eventually reach the surface, breaching at the seafloor around the well. Fractures can also extend to neighboring wells and create a flow path to the seafloor if those wells are not properly cemented.

Since the structural, conductor, and surface casing strings are the foundation of the well, obtaining a quality cement sheath is critical to achieving well objectives.

1.5 Challenges for Controlling SWF

The following factors make drilling and cementing sections with SWF potential challenging:

- a) Temperatures at the mudline are low, usually in the range of 1.5 °C to 13 °C (35 °F to 55 °F). The geothermal gradients found in deepwater areas may be sequestered as a result of the water-depth effect and may suppress wellbore temperatures throughout the entire stratigraphic column. In other areas, the geothermal gradient may recover quickly with depth. The low temperatures result in slow hydration of the cement, often making special slurries or additives, or both, necessary.
- b) Pore and fracturing pressures are close due to the depositional environment, making the drilling and cementing pressure margins narrow.

- c) The hole section is usually drilled riserless, with no means to control flow at the wellhead, and returns are observed from a remotely operated vehicle (ROV).
- d) In development projects, tophole casing strings may be in close proximity to each other through the SWF zone.

The shallow-water flow conditions described in this document exist in wells drilled in water depths greater than 150 m (500 ft) and more commonly at water depths greater than 300 m (1000 ft). Shallow-water flow sands are typically encountered at depths of 180 m to 760 m (600 ft to 2500 ft) below the mud line (BML). The conditions favoring the formation of shallow-water flow zones include:

- high rate of deposition [>450 m per million years (>1500 ft per million years)] in sedimentary basins of current or ancestral river complexes, such as the Mississippi River depocenter;
- areas with substantial regional uplift, in which once deeply buried sediments are encountered at shallow depths, such as the Caspian Sea;
- continental slope regions subject to large-scale subsea slides, such as the Storegga Slide area in the Norwegian Sea.

1.6 Summary of Considerations

Isolating a shallow flow zone with cement is an interdependent process. Individual process elements, such as slurry design and testing, applied engineering, and job execution all impact the ability to successfully isolate the wellbore and establish structural integrity. Superimposed upon these elements are the conditions found in the well at the time of cementing.

Certain cementing process elements contained in Annex D may be individually critical to isolating a potential flow zone or may be of minor consequence until made critical by a separate (sometimes unrelated) event or past well engineering decisions. Conversely, certain elements may not be dominant factors in the success of one cementing operation, yet are vitally important in another.

Collectively, the elements described in Annex D produce the design, engineering, and operational framework for successfully isolating a potential flow zone.

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document applies (including any addenda/errata). Not all documents listed may apply to an individual's specific needs. The body of the standard should be referred to for how these documents are specifically applied.

[API Recommended Practice 10B-2](#), *Testing Well Cements*

[API Recommended Practice 10B-3](#), *Testing of Deepwater Well Cement Formulations*

[API Recommended Practice 10B-4](#), *Preparation and Testing of Foamed Cement at Atmospheric Pressure*

[API Recommended Practice 10B-6](#), *Determining the Static Gel Strength of Cement Formulations*

[API Recommended Practice 75](#), *Development of a Safety and Environmental Management Program for Outer Continental Shelf (OCS) Operations and Facilities*

3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

For the purposes of this document, the following terms and definitions apply. In addition to those listed below, other definitions and abbreviations may be found in oilfield glossaries.

3.1.1

annulus

The space between the borehole and tubulars or between tubulars, where fluid can flow.

3.1.2

barrier (barrier element)

A component or practice that contributes to the total system reliability by preventing liquid or gas flow if properly installed.

3.1.3

blowout preventer

BOP

A device attached to the casing head that allows the well to be sealed to confine the well fluids in the wellbore. See [API RP 53](#) or other relevant standards for further information.

3.1.4

borehole

Wellbore sections that are not cased with pipe; commonly called “open hole.”

3.1.5

bottomhole assembly

BHA

Bottomhole assembly is the collection of the bit, drill collars, stabilizers, reamers, hole openers, MWD/LWD/PWD, mud motor, directional steering system, and other tools at the base of the drill string that serve special purposes associated with drilling.

3.1.6

conductor

Provides structural support for the well, wellhead, and completion equipment, and often provides hole stability for initial drilling operations. This casing string is typically not designed for pressure containment. In some cases, the conductor casing may serve to isolate shallow formations, similar to a surface casing.

3.1.7

critical gel strength period

CGSP

The time between the development of the critical static gel strength (CSGS) and a static gel strength of 250 Pa (500 lbf/100 ft²).

3.1.8

critical static gel strength

CSGS

The static gel strength of the cement that results in the decay of hydrostatic pressure to the point at which pressure is balanced (hydrostatic equals pore pressure) at a point adjacent to the potential flowing formation(s).

3.1.9

equivalent circulating density

ECD

The effective density of the circulating fluid in the wellbore resulting from the sum of the hydrostatic pressure imposed by the static fluid column and the friction pressures.

3.1.10**flow checks**

An observation, usually by ROV when riserless, of the condition of the well during a noncirculating period to determine if flow is occurring.

3.1.11**formation fluids**

Fluids present within the pores, fractures, faults, vugs, caverns, or any other spaces of formations are called formation fluids whether or not they were naturally formed or injected therein. The physical state of formation fluids may be liquids or gases and include various types such as hydrocarbons, fresh or saline water, carbon dioxide, hydrogen sulfide, etc.

3.1.12**fracture gradient****FG**

A factor that, when multiplied by the true vertical depth, calculates the fracturing initiation pressure.

3.1.13**Drive pipe****Jetted pipe**

Casing that supports unconsolidated sediments providing hole stability for initial drilling operations. This is normally the first string set and provides no pressure containment. This string can also provide structural support to the well system. See also 3.1.26, definition for structural pipe (or casing).

3.1.14**logging while drilling****LWD**

The measurement of formation properties during the drilling of the borehole by logging tools installed in the BHA.

3.1.15**measurement while drilling****MWD**

The measurement of physical properties while drilling, such as pressure, temperature, and borehole trajectory, by tools installed in the BHA.

3.1.16**mudline**

As referenced in subsea operations, refers to the seafloor.

3.1.17**overbalance pressure****OBP**

The amount by which the hydrostatic pressure exceeds the pore pressure of a formation.

3.1.18**pad mud**

Weighted drilling fluid left in the wellbore to maintain wellbore stability and well control prior to running casing during riserless drilling operations.

3.1.19**pore pressure****PP**

Pore pressure is the pressure of the fluid inside the pore spaces of a formation.

3.1.20
pressure while drilling
PWD

The measurement of downhole pressure while drilling by a tool installed in the BHA.

3.1.21
rathole

Bottom part of the drilled hole below the shoe of the casing to be cemented.

3.1.22
rate of penetration
ROP

Common term for drilling rate; usually expressed in meters per hour (feet per hour).

3.1.23
riser

The extension of the wellbore from the subsea BOP stack to the drilling vessel. The riser provides for fluid returns to the drilling vessel, supports the choke, kill, and control lines, guides tools into the well, and serves as a running string for the BOP stack.

3.1.24
shallow-water flow
SWF

Water flows from permeable formations at shallow depths below the mudline in wells drilled in deep ocean waters.

3.1.25
static gel strength
SGS

Shear strength (yield stress) measurement derived from the force required to initiate flow of fluid at rest.

3.1.26
structural pipe (or casing)

Pipe utilized to facilitate the drilling of a well, but not intended for pressure containment after the well has been drilled. Supports unconsolidated sediments and provides hole stability for initial drilling operations, axial support for casing loads, and bending loads from the wellhead. See also 3.1.13, definition for drive or jetted pipe.

3.1.27
subsea wellhead

A wellhead that is located near the seafloor.

3.1.28
surface casing

Casing run to isolate shallow formations. Typically, the BOP is run after the surface casing is set.

3.1.29
wellbore

The borehole or cased hole sections in a well.

3.1.30
wellhead

A device upon which the BOP and casing hangers are installed during the well construction phase. In addition, the system of spools, valves, and assorted adapters that provides pressure control of a producing well. The wellhead also incorporates a means of hanging the production tubing and installing the Christmas tree and surface flow-control facilities in preparation for the production phase of the well.

3.1.31**wait on cement****WOC**

Waiting on cement, normally expressed in hours, is the period of time after the cement slurry has been placed until the time it develops sufficient strength and subsequent drilling or completion operations can resume.

3.2 Acronyms and Abbreviations

ASTM	American Society of Testing Materials
BHA	bottomhole assembly
BHCT	bottomhole circulating temperature
BHP	bottomhole pressure
BHST	bottomhole static temperature
BML	below mudline
BOP	blowout preventer
BWOC	by weight of cement
CGSP	critical gel strength period
CSGS	critical static gel strength
ECD	equivalent circulating density
FG	fracture gradient
GOM	Gulf of Mexico
HPL	high-performance lightweight
HTHP	high temperature, high pressure
ID	inner-diameter
IOGP	International Association of Oil and Gas Producers
ISO	International Organization for Standardization
LCM	lost circulation material
LWD	logging while drilling
MWD	measurement while drilling
OBP	overbalance pressure
OCS	outer continental shelf

OD	outer-diameter
PP	pore pressure
psi	pound-force per square inch
PWD	pressure while drilling
QA	quality assurance
QC	quality control
ROP	rate of penetration
ROV	remotely operated vehicle
SG	specific gravity
SGS	static gel strength
SPE	Society of Petroleum Engineers
SWF	shallow-water flow
TD	total depth
TOC	top of cement
WOC	wait on cement

4 Drilling Practices to Reduce the Risk of Shallow-water Flows

4.1 General

Tophole drilling practices have a significant impact on the ability to achieve zonal isolation in the presence of shallow-water flows. The importance of constructing a structurally sound foundation for the well cannot be overemphasized. Failure to establish and maintain zonal isolation in the tophole section of a deepwater well will, in many cases, compromise the ability to achieve the overall well objectives. Poor drilling practices can lead to issues ranging from lower-than-expected leak-off values at the casing shoe that impact the ability to maintain the planned casing program, to the loss of containment of wellbore fluids.

From a planning and job execution perspective, it is imperative that information about the conditions expected during the drilling of the tophole interval be communicated to all parties involved in the cementing operations. A summary of the results from the hazard assessment of the drill site should be provided to the cementing service provider to be used in the development of the cementing program, or be used by the operator in the development of the cementing basis of design. Typically, the information provided in the shallow hazard assessment will include the expected location, thickness, and severity of shallow-water flow intervals, as well as other hazards, such as possible hydrocarbon bearing or loss circulation zones. Representatives from the cementing service provider and operator should review the mitigation measures being proposed for the anticipated tophole hazards.

4.2 Well Spacing

Individual well spacing and drilling order during deepwater development should be designed to minimize the impact of drilling operations on adjacent wells. Shallow-water flow can cause changes in the local mechanical stresses affecting both the well experiencing the flow and adjacent wells. Well arrangement with the greatest distance between adjacent wellbores (at the flow zone) can reduce the risk of damage to a well from a nearby well that is experiencing flow. In cases where deepwater development includes wells currently being produced intermixed with wells that are being drilled, be aware of the temperature influence a producing well may have on an adjacent wellbore that is being drilled.

4.3 Hole Conditions

The condition of the borehole established during the drilling operation will have a major bearing on the quality of the hydraulic isolation established by the cementing operation. Of the hole conditions impacting cementing success, hole diameter, hole tortuosity, and wellbore stability are of engineering concern.

4.4 Hole Enlargement

Hole enlargement makes it difficult to successfully install and cement a casing string, which can lead to post-cementing problems such as casing buckling. Buckled casing in the enlarged sections may prevent re-entry into the well. Uncontrolled flows can also lead to compaction and subsidence of the flow zones, impacting the integrity of nearby wells or structures.

Hole enlargement can lead to lower annular velocities, increasing the likelihood of cuttings loading while drilling, raising ECD, and potentially causing annular pack-off. Lower annular velocities also make it more difficult to displace wellbore fluids during cementing. Hole enlargement makes centralization (an important element of effective drilling fluid removal) more difficult.

Causes of hole enlargement include:

- removal or “mining” of formation materials from the wellbore by shallow-water flows;
- hydraulic erosion, which is caused by excessive bit nozzle velocity and turbulence at the bit;
- a high fluid loss drilling fluid causing high near-wellbore pore pressures (no distinct pressure gradient across a sealing filter cake).

NOTE This means that near-wellbore pore pressure is equal to the pressure exerted by the drilling fluid, resulting in a near-wellbore radial effective stress of zero. This loss of stress eliminates the effective overbalance acting to support the formation.

Hole enlargement is controlled in a variety of ways, including optimizing the drilling parameters and the density and composition of the drilling fluid.

4.5 Hole Size Optimization

Hole size should be optimized such that cuttings removal can be achieved at annular velocities appropriate with the drill-pipe/collars/BHA and rig pumps to be used.

Additionally, consider the annular dimensions with casing in the hole and the ability to place cement at the desired rates, considering displacement mechanics. Drilling engineers should work together with the cementing companies to design for effective drilling-fluid removal and annular isolation.

4.6 Hole Cleaning

Hole cleaning is a direct function of annular geometry, annular velocity, cuttings size, mud/sweep viscosity, and density.

Understanding the increase in equivalent circulating density (ECD) from cuttings in the return fluid and from running pipe has led to changes in operating practices that have reduced formation failure. Using a sufficient flow rate and controlled rate of penetration (ROP) will limit the effect of the cuttings load in the annulus. Regular sweeps help remove cuttings, keep the annulus pressure lower, and help prevent lost circulation. Weighted viscous sweeps provide additional cuttings lifting capacity. Viscous sweeps should be formulated with significantly higher viscosity than the existing fluid. The sweep volume should be equal to between 30 linear meters to 75 linear meters (100 linear feet to 250 linear feet) of annulus. Typically, circulation bottoms-up or sweeps are run every stand. Foamed sweeps can be effective at removing cuttings prior to running and cementing casing.

4.7 Use of Pilot Holes

In areas not previously drilled, a pilot hole is sometimes drilled to surface casing depth to provide evidence about the tophole conditions. The size of the pilot hole is dependent on many factors, such as water depth, depth to the surface casing setting point, etc. Typically, a 251 mm (9 ⁷/₈ in.) or 311 mm (12 ¹/₄ in.) hole is drilled.

The risk of a SWF should be evaluated against the need for sacrificial mud and any constraints imposed by its use in opening the smaller diameter hole to run casing. These factors, plus the rig's sacrificial mud storage capacity, drill pipe size, and mud pump capacity, should be used to choose the most appropriate approach for these areas. When circulating with the pump rate held constant, the PWD measurements can help identify a potential flow interval. If a significant increase or decrease in pressure is observed, stop drilling and use a remotely operated vehicle (ROV) to check for flow. If there is flow, heavy mud can be pumped to kill the well prior to drilling ahead.

4.8 Full Diameter Holes

A full diameter borehole is suitable in most development scenarios, where well conditions, presence, and depth of flow zones are known, or with proper engineering, where sufficient volumes of weighted mud are available to kill any possible flow. Drilling a full diameter hole has the advantage of minimizing trips and minimizing the amount of time a hole section is open. In many shallow-water flow environments, there is a correlation between the time the hole section is open and the likelihood (or severity) of a shallow-water flow event.

4.9 Lost Circulation

Lost circulation is due to wellbore pressures exceeding the fracture gradient of the exposed formations. The formation integrity of the poorly consolidated tophole sediments found in many deepwater basins can be low, making lost circulation a possibility. While the drilling fluids being used in the tophole section of the well are usually seawater or seawater with gel sweeps, high ECD can occur due to loading of cuttings in the fluid, so that the annular pressure exceeds the formation fracture gradient.

The minimum drilling fluid density is maintained such that the annular pressure exceeds the pore pressure of any SWF intervals when static. The maximum drilling fluid density should not exceed formation integrity while circulating. The difference between this minimum and maximum can be small. A contributing factor to the ECD is the cuttings, which are carried out of the well by the drilling fluid. The amount of cuttings in the fluid can be controlled to avoid exceeding the fracture gradient. In order to do this, the flow rate should be balanced against controlling the rate of penetration (ROP) to reduce production of cuttings. Periodically circulating bottoms-up with viscous or weighted sweeps can aid in keeping the hole clean.

PWD measurements can aid in borehole pressure management. When pressure increases are noted and a static flow check indicates that the well is not flowing, remedial action can be taken to avoid breaking down formations due to excessive cuttings loading or annular pack-off.

For best results, there should be no flow and minimal mud losses, either due to lost circulation or fluid loss. Appropriate lost circulation material (LCM) and bridging agents can be used to minimize mud losses.

4.10 Flow Detection

PWD measurements can provide the earliest possible means to recognize flows so that appropriate action may be taken to mitigate them. Resistivity at the bit can also be used to indicate when potential overpressured sands have been penetrated. If PWD measurements is not available, early flow detection can come from constantly monitoring returns by video from the ROV. Additionally, static flow checks should be made after each connection and after sweeps to determine if shallow flow is occurring. In the case that a static flow check indicates that there is no flow, it is still possible that a SWF could occur if the overbalance pressure is reduced. Monitoring for as long as one hour may be required. If SWF is encountered, the flow should be killed as quickly as possible. The rate of shallow-water flows is difficult to judge based on visual ROV observations. With this in mind, allowing a seemingly "smaller" flow for even short periods of time may later result in an unacceptable wellbore for cementing and subsequent mitigation of the SWF. Prevention of SWF ensures the highest probability of successfully attaining the objective of setting casing with a competent cement sheath. If flows occur, minimize the flowing time to avoid enlargement of the hole.

Drilling on a single trip with a full diameter bit or bit-and-reamer combination minimizes the time the hole is open, reduces the number of trips, and is suitable for locations where the conditions and severity of SWF are known. Consider the impact of having two wellbore diameters when using a bit and reamer on ECD and cuttings management.

4.11 Rate of Penetration

Rate of penetration should be controlled as indicated by annular PWD readings or hydraulic modeling and pressure management. Higher ROP reduces open hole time, thus minimizing the exposure of water-sensitive formations to a noninhibitive water-based mud system. This advantage should be balanced against the increase in ECD due to loading of cuttings in the fluid.

When optimizing ROP, one important consideration is maintaining the ability to clean the hole. The drilling fluid should be capable of efficiently carrying the larger volume of cuttings out of the hole. Ineffective hole cleaning can lead to higher ECDs, bit balling, higher drag, annular pack-off, etc. These conditions can lead to lost circulation and other wellbore instability problems. ROP in large, tophole sections is frequently restricted by ECD and hole cleaning constraints.

4.12 Drilling Fluids

Several criteria should be considered when designing drilling fluids, such as (but not limited to):

- fluid should meet all regulatory requirements;
- density and associated ECD within pore/frac margin;
- hole cleaning;
- formation stability;
- logistics.

4.12.1 Weighted Drilling Fluid

Although seawater augmented by hole cleaning sweeps is effective above the SWF interval, the fluid density and composition may sometimes be adjusted at shallower depths to provide hole stability. Frequently, drilling fluid is made in batches and stored in a concentrated form (higher density) to conserve storage space. When necessary, this mud is then diluted, usually with seawater, to the desired density to finish drilling the hole section.

4.12.2 Sweeps

When drilling with seawater or after the hole is drilled with mud, sweeps should be used to clean the hole prior to placement of kill or pad mud. The use of high-viscosity, weighted sweeps will enhance hole cleaning. To be effective, sweeps typically have different properties (higher viscosity and/or density) than the existing drilling fluid and are typically of sufficient volume to cover 30 linear meters to 75 linear meters (100 linear feet to 250 linear feet) of annulus. PWD analysis can aid in determining when the hole is clean. As a minimum, a sweep should be used to remove cuttings upon reaching TD. The unique properties of foamed sweeps make them another option for hole cleaning.

4.12.3 Pad Mud

Pad mud is the fluid placed in the well at the end of drilling the hole section. The pad mud remains in the hole until it is circulated out during cementing, which can be 12 hours to 36 hours. The fluid properties should be selected with the goal of controlling hole enlargement or sloughing/caving pad mud. The pad mud properties should be considered when designing the fluids and flow regimes used in the cementing process.

The pad mud should have proper fluid loss control to prevent uncontrolled filter cake development across permeable formations. A mud with low fluid loss and a thin filter cake is recommended if permeable formations are present. For ultra-high permeability shallow sands with high SWF potential, bridging agents (medium-to-coarse granular lost circulation materials) may be required to prevent leak-off, which could result in a loss of hydrostatic pressure and a subsequent flow. Static gel strength and low shear rheology at downhole conditions should be low and nonprogressive, but not at the sacrifice of drill cuttings transport or barite support.

4.12.4 Rathole Fluid

If casing is not to be run to bottom, the rathole should be filled with a mud or a compatible spacer having a density higher than the cement to prevent the rathole fluid from swapping with the cement during or following placement. A cement-filled rathole may pose challenges on drilling out after the job, such as the risk of kicking off in soft formations. The fluid spotted in the rathole should be treated in much the same way as the other kill or pad muds to minimize hole enlargement and wellbore instability.

4.13 Detecting and Characterizing SWF Zones

Annular pressure-while-drilling tools directly measure the annular pressure and on some tools, the internal pressure of the drill string. The pressure-while-drilling tool measures the system pressure, which is the sum of hydrostatic pressure and annular friction pressure. When not pumping, the pressure-while-drilling tool measures the hydrostatic pressure in the annulus.

The use of the pressure-while-drilling tool to detect a SWF has a major advantage over using an ROV to monitor the seabed, as the SWF can be detected. Measuring the annular pressure during the SWF allows the pore pressure of the flowing interval to be approximated so that the flow can be killed. Caution should be exercised when interpreting the pressure measurement, as sudden pressure increases can also be caused by an annular pack-off above the tool.

Gamma-ray and resistivity logging tools can be used to identify the location of sand and shale formations in the section to be drilled by direct measurement as they pass each formation. They can also be used to

identify the thickness of the zone that is flowing if the assembly has drilled deep enough to expose the entire zone. Correlation to offset wells can also be performed if knowledge of the geological structure and predicted formation depths is obtained from seismic data. This allows the location of known SWF zones to be anticipated. The distance between the bit and the tools will result in a delay between penetration of a zone and receiving the data at surface.

For details on shallow hazard assessment, site selection, and monitoring of shallow flow conditions, see Annex C.

5 Flow Control

If the probability of flow is high, drilling operations can be designed utilizing weighted drilling fluids to prevent flows from occurring while drilling. If a flow is identified while drilling, kill the well as soon as possible. Sufficiently large volumes of kill weight fluid should be maintained on the rig or in stand-by support vessels. Successful control of flows can be difficult or impossible to achieve after extensive flow has occurred or after the casing has been cemented. Immediate attempts should be made to control the flow, reduce wellbore enlargement, instability, and possible damage to nearby wells.

- a) If flow cannot be controlled in a timely fashion, abandoning the drill site may be required.
- b) If the flow can be controlled, but the density of the kill weight fluid prevents circulation of cement without losses, the probability of a successful cementing operation is low. Consideration should be given to site abandonment.
- c) If an uncontrollable flow occurs outside the previous casing, strong consideration should be given to site abandonment.

NOTE Flow severity also impacts the slurry design criteria required for flow control and narrows the acceptable tolerance levels for slurry parameters. Flow severity should be considered in the cement design. See Annex C for information on flow severity characterization.

6 Operational Considerations

6.1 Wellbore Preparations Prior to Tripping Out of the Hole

Upon completion of drilling the tophole section, the wellbore may not be in optimal condition for successful cementing. While cuttings loadings should be controlled during drilling to prevent losses, the ECD once casing is on bottom will be higher and the acceptable amount of cuttings may be less. If there are indications that a significant amount of cuttings are still in the hole after the hole section has been drilled to TD, pumping viscous sweeps will aid in removing those cuttings prior to tripping out of the hole with the drill string. Monitoring returns during these sweeps may provide a visual indication that the wellbore is clean.

The fluid properties required for drilling the well may not be consistent with the properties that facilitate their removal during the cementing process. Replacing the drilling fluid with an engineered pad mud prior to tripping out of the hole will help minimize deterioration of hole conditions and maximize the probability of achieving isolation during the cementing operation.

A fluid with good fluid loss control that provides a thin filter cake is desirable both for hole stability and for improved cement sheath quality. The rheological properties of the spotting fluid should be suitable for good displacement by the subsequent preflush or spacer and cement. A fluid with low, non-progressive gel strengths will be easier to displace from the wellbore during cementing. It is important to measure the rheology and gel strength at the cool temperatures they will be exposed to in the well. Engineering software, which is discussed in more detail as specified in 7.6, is useful for determining suitable fluid properties.

Minimizing the time between final placement of the pad mud prior to tripping out of the hole and commencing circulation prior to cementing when SWF hazards exist will aid in maintaining a wellbore that is in better condition for subsequent cementing.

6.2 Casing and Casing Hardware

6.2.1 Casing Running Procedures

Casing with appropriate hardware should be made up and run as quickly as safely practical. Casing is normally made up ahead of time and temporarily suspended in open water from the casing running tool. Computer simulators can be used to predict surge and swab pressures. The results of these simulations can provide guidance on maximum running rates.

6.2.2 Float Equipment

Float equipment is used to prevent the cement from flowing back into the casing when pumping is stopped or pressure released, or both. For test procedures of various classes of float equipment and associated mechanical components see [API 10F](#).

Float equipment choice should be matched to anticipated bottomhole temperatures and the pressure differentials expected at the end of the cement job. Specialized float equipment including auto-fill, sideported, and custom profiled is also available to address the functionalities of surge-reduction and collapse protection, improved hole cleaning, and ease of running casing, respectively.

A float collar and a float shoe can be used together to provide redundant flow-back control. Some LCM in the drilling fluid or cementing fluids, or both, may preclude or hamper the use of certain float equipment valve designs. Standard float equipment is not designed to provide a gas-tight seal.

If computer modeling predicts excessive surge pressures while running casing, special float equipment can be used to reduce the surge pressure. Float valves may be configured to allow the casing to fill automatically from the shoe, thereby reducing the surge pressure. Auto-fill equipment will have manufacturer guidelines associated with the process of converting the floats back to the standard back-flow, check valve configuration. It is important to incorporate these procedures into the casing, running and cementing program so that the float equipment is in standard check valve configuration before the cement job is started.

The impact of auto-fill tools while running casing across potential flow zones is an important consideration. Operational response plans should be in place and implemented if flow occurs.

6.2.3 Centralizers

Appropriate casing centralization is important to successful cement placement and zonal isolation. Casing centralizers exist in many models and designs and are generally categorized as either rigid, solid or bow-spring models. For additional information see 7.5, [API 10D-2](#), [API 10TR4](#) and [API 10TR5](#).

6.3 Wellbore Conditioning with Casing on Bottom

Circulating and conditioning the fluids in the well once casing is on bottom and prior to cementing is a key step in achieving successful isolation and structural support. While the well was static, the fluid in the wellbore may have gained significant gel strength and circulating at this point will aid in breaking that gel strength prior to the cement job. Pre-job circulation will also aid in further removal of residual cuttings from drilling or caving's that may have occurred while the well was static. Removal of these solids is important because if the annulus becomes packed-off during cementing, the job objectives may be compromised.

A final static flow check should be performed just prior to the cement job to verify the well is not flowing. If the well is flowing, it cannot successfully be cemented and higher density mud should be pumped to kill the flow. When a marine riser is not installed, the drill pipe cannot be kept full of weighted fluid due to the