

Annular Casing Pressure Management for Offshore Wells

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Introduction

This document is intended to serve as a guide for managing annular casing pressure in offshore wells (formerly designated as API RP 90) and is now designated as API 90-1. A similar document has been prepared for annular casing pressure management for onshore wells, API 90-2. However, events involving annular casing pressure (ACP) incidents and risks prompted a revision of this document; a re-issue of the document was not considered prudent without revisiting the issues and risks involved in offshore ACP management.

Prevention of unintended ACP through proper well design and construction is important. However, this issue is beyond the scope of this document. Prevention of annular casing pressure is addressed in several other standards.

Similarly, remediation of ACP is beyond the scope of this document. Remediation is well-centric; it depends upon the specific conditions that exist in the individual well, the condition of that well, the level of ACP and the stresses that have been and are being imposed upon it. Thus, listing and describing all the potential remedies for eliminating or even reducing ACP would be far too massive for a generalized document.

This document covers monitoring, diagnostic testing, and the establishment of a maximum allowable wellhead operating pressure (MAWOP) that adequately describe those conditions where annular casing pressure is monitored and managed. Documentation requirements are outlined for the monitoring of annular casing pressure for various well types that exist offshore. Included is a discussion of risk assessment methodologies that can be used for the evaluation of well situations where the annular casing pressure is not within the MAWOP guidelines.

This document recognizes that ACP can result in various levels of risk to personnel, property, and the environment. The risks depend upon many factors including design of the well and the source of the ACP. This document provides guidelines that cover a broad range of casing annuli pressures that can be managed in a logical fashion while maintaining an acceptable level of risk. Annular casing pressures that do not conform to the conditions anticipated in this document may still be managed using similar logical methods to reduce risks to an acceptable level, but these risks should be evaluated on a case-by-case basis.

There are no known specific guidelines for managing risks associated with ACP that apply uniformly across the board. Further, each offshore operator is expected to have its own risk management system to deal with wells under their control. Attempts to standardize risk analysis and mitigation measures would result in an infinite number of solutions depending upon the conditions encountered. Therefore, this document attempts to provide general guidelines for operating wells with ACP.

Annular Casing Pressure Management for Offshore Wells

1 Scope

This document provides guidance for managing annular casing pressure in offshore wells of various types to ensure that well integrity is maintained, and risks are managed. It is similar in scope and purpose to API 90-2, which addresses this annular casing pressure management for onshore wells.

This document is meant to be used for existing offshore wells that exhibit annular casing pressure, including thermally induced casing pressure, sustained casing pressure (SCP) and operator-imposed pressure. It contains general information regarding annular casing pressure that is applicable to all offshore well types: fixed platform wells, subsea wells, hybrid wells and mudline suspension wells. Many risks are the same between well types, so much of the information has been collected into single sections that apply to all of them. Where necessary, information about individual well types is separated for clarity.

2 Normative References

There are no normative references in this document.

3 Terms and Definitions

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

3.1

ambient pressure

Pressure external to the wellhead.

NOTE In the case of a surface wellhead, ambient pressure is defined as zero psig (kPa). In the case of a subsea wellhead, it is equal to the hydrostatic pressure of a column of seawater at the depth of the subsea wellhead.

3.2

annular casing pressure

ACP

Pressure measured at the wellhead in the space between the tubing and casing or in the space between other casing strings that terminate in the wellhead.

3.3

annular casing pressure anomaly

A condition that differs from what is typical or expected, or which differs from that predicted by a theoretical model.

3.4

annulus

The space between the borehole and tubulars or between tubulars, where fluid (liquid, gas, or both) can flow.

NOTE The designation for the inner-most annulus, often the space between tubing and production casing, is the "A" annulus. Outer casing string annuli are designated "B," "C," "D," etc. as pipe size increases in diameter.

3.5

barrier element

A pressure and flow containing component that relies on other component(s) to create a well barrier envelope and is verified to conform to specific acceptance criteria.

3.6

barrier envelope

Envelope of one or more dependent well barrier elements that prevents fluids from flowing unintentionally from the formation, into another formation, or to the surface.

3.7

casing

Pipe permanently installed in a well that extends from the wellhead to a point at or near the total depth of the hole section used to isolate formation pressures and fluids in a portion of the wellbore.

NOTE Casing can be installed in an open wellbore or inside another casing string also suspended from the wellhead thereby creating an annulus between the two casing strings.

3.8

casing string

The total length of casing that is run in a well during a single operation and hung off in the wellhead.

NOTE A casing string consisting of more than one type of casing is called a combination casing string. A casing string with more than one diameter is called a tapered casing string.

3.9

completion string

production string

Completion components installed in a well consisting, primarily, of tubing and additional components such as the subsurface safety valve (SSSV), gas lift mandrels, chemical injection, and instrument ports, landing nipples, and packer or packer seal assemblies.

NOTE The completion string is run inside production casing and used to convey produced fluids (liquids, gas, or both) to the surface from the reservoir or injected fluids to the reservoir.

3.10

conductor casing

The first casing string providing both structural support for the wellhead, subsequent casing string and completion equipment, and hole stability for shallow drilling operations.

NOTE 1 This shallow casing string is designed for only low-pressure containment, and it may be equipped with a low-pressure wellhead housing in subsea wells in which a high-pressure wellhead housing is installed.

NOTE 2 Multiple shallow conductor strings can be run in a well depending on soil strengths and shallow hazards that require isolation behind pipe.

3.11

Default Designation Method

DDM

A simple method for de-rating tubulars for the calculation of the MAWOP on wells known to have very low ACP or where the condition of tubulars is unknown.

3.12

diagnostic threshold

DT

The pressure range above or below which diagnostics are warranted to determine the type (sustained or thermally induced) and characteristics of the annular casing pressure.

3.13**Explicit Deration Method****EDM**

A tubular deration method used in cases where significant casing wear, known tubular corrosion or erosion has occurred or for operations under high temperatures to calculate an adjusted minimum internal yield pressure (MIYP) and an adjusted minimum collapse pressure (MCP) for determining MAWOP.

3.14**formation integrity**

A measure of the capability of the exposed formation to resist fracturing due to applied hydraulic pressure.

NOTE Usually determined by one of several pressure integrity test (PIT) methods such as a Leak-off Test (LOT) or Formation Integrity Test (FIT).

3.15**Formation Integrity Test****FIT**

Application of pressure by superimposing a surface pressure on a fluid column to determine ability of a subsurface zone to withstand a certain pressure.

3.16**fracture gradient****FG**

The maximum pressure the formation can withstand without fracturing, resulting in whole fluid losses.

3.17**hazard**

Source of potential harm or a situation with a potential to cause loss (any negative consequence).

3.18**hybrid well**

A well drilled using a subsea wellhead and completed with a surface casing head, a surface tubing head, a surface tubing hanger and surface tree.

NOTE A hybrid well can have either one casing string (single-bore production riser) or two casing strings (dual-bore production riser) extending from the surface wellhead to the subsea wellhead. These are often located on floating production facilities such as tension-leg platforms or spars.

3.19**intermediate casing**

Casing that is set after running shallow surface casing/conductor and before running production casing. Intermediate casing is set when geological characteristics, formation pressures, hole instability or drilling objectives require that a barrier element be installed to facilitate further well construction.

NOTE 1 Intermediate casing may be used to isolate over-pressured or troublesome formations or to allow use of heavier mud to counter higher reservoir pressures as drilling progresses.

NOTE 2 Multiple intermediate strings can be run in a well.

3.20**leak**

Unintended and undesired movement of fluid or loss of pressure containment.

3.21**Leak-off Test****LOT**

Test method used to determine the pressure at which the formation just begins to accept fluid at a point below a casing shoe.

NOTE 1 This pressure is often used to approximate the formation fracture pressure at the shoe when the test is terminated before reaching complete formation breakdown.

NOTE 2 In an extended LOT pressure is increased until the formation parts (fractures).

3.22**liner**

A tubular string that does not terminate in the wellhead.

NOTE 1 Liners are anchored, suspended, or positioned inside the previous casing string.

NOTE 2 Liners create a situation where ACP cannot be monitored.

NOTE 3 The liner top can be fitted with special components, such as a tieback sleeve, polished bore receptacle, a liner top packer, or a combination thereof.

3.23**logging-while-drilling****LWD**

Measurement of formation properties while drilling using pipe-conveyed logging tools that can communicate to the surface using some type of telemetry.

3.24**maximum allowable wellhead operating pressure****MAWOP**

Pressure limit established for a particular annulus, measured at the wellhead relative to ambient pressure.

NOTE MAWOP applies to all sources of pressure, including SCP, thermally induced casing pressure and operator-imposed casing pressure.

3.25**minimum collapse pressure****MCP**

Differential pressure across the tubular wall that is sufficiently high to collapse the tubular.

NOTE See API 5C3.

3.26**minimum internal yield pressure****MIYP**

Differential pressure across the tubular wall that is sufficiently high to reach the minimum yield strength on the inner diameter of the tubular.

NOTE See API 5C3.

3.27**monitoring**

Observation of the operating parameters of a well, whether continuously or on a predefined frequency to assure that they remain within their operating limits.

3.28**mudline suspension well****MLS**

An offshore well equipped with both a surface wellhead and a system that supports the weight of casing strings located beneath the mudline.

NOTE 1 Casing hangers at the mudline suspension typically do not seal so each annulus can be monitored through wellhead side outlets.

NOTE 2 Outer casing strings can be detached at the mudline suspension with only the inner strings providing a production riser to the surface wellhead.

3.29**offshore well**

A well with a surface hole location off the coastline.

3.30**operating limits**

A set of established criteria, or limits, beyond which a device or process should not be operated.

3.31**operator-imposed pressure**

Pressure, which is intentionally applied and managed at the surface for operational purposes such as gas lift, water injection/disposal, and annular monitoring.

3.32**packer**

Mechanical device with a compressible sealing element used for the prevention of fluid (liquid, gas, or both) flow and pressure between conduits or within an annular space.

NOTE 1 A packer is a component within the completion string used to isolate produced or injected fluids (liquids, gas, or both) from the upper portion of the tubing × production casing annulus.

NOTE 2 Multiple packers that can accommodate two or more tubing strings can be used within a single production casing string to isolate various portions of the annulus.

3.33**pressure test**

Application of pressure differential to ascertain the mechanical and sealing integrity of a component.

3.34**production casing**

The inner-most casing string terminated at the wellhead typically set through hydrocarbon-producing interval(s).

3.35**production riser****production casing riser**

Pipe extending from the surface wellhead to the subsea wellhead in hybrid wells.

3.36**risk**

The combination of the consequences of an event and the associated likelihood of its occurrence.

3.37**risk assessment**

A systematic analysis of the risks from various activities with a rational evaluation of their significance by comparison against predetermined standards, target risk levels and other risk criteria, or a combination thereof.

NOTE Risk assessment is used to determine risk management priorities.

3.38
rated working pressure
RWP

The pressure established by the manufacturer of a component in a well as the maximum safe pressure at which the component can be operated on a continuous basis; normally a fraction of the maximum test pressure of the component.

NOTE Also known as simply "rated pressure"

3.39
Simple Designation Method
SDM

A tubular de-rating method that employs MCP or MIYP of a casing string to calculate MAWOP.

3.40
shut-in

Interrupting the flow path of the entire well or a portion thereof using a control such as a valve.

3.41
structural casing
drive pipe

Large diameter pipe string used to facilitate well construction and to provide structural support for the wellhead and subsequent casing strings, but not designed for pressure containment during drilling operations.

NOTE The purpose of this string is to support unconsolidated sediments, (i.e. provide hole stability for initial drilling operations), provide axial support for casing loads, and resist bending loads from the wellhead and BOP stack.

3.42
subsea well

A well constructed with a subsea wellhead that is completed with a subsea tree.

3.43
subsea wellhead

A specialized wellhead installed at or near the mudline from which casing and tubing strings are suspended.

3.44
supervisory control and data acquisition
SCADA

Data acquisition systems which are used to monitor and control operation of multiple wells over large areas.

NOTE Most control actions are performed automatically by RTUs (remote terminal units) or by PLCs (program logic controllers).

3.45
surface casing

The first pressure-containing tubular run within the conductor string or structural casing (drive pipe) and cemented back to the mudline.

3.46
surface well

An offshore well with a wellhead that extends to a fixed platform from which all casing strings are suspended and to which a tubing head and surface tree are attached, all of which are situated above sea level.

3.47**surface wellhead**

A wellhead situated above the water line on an offshore well.

NOTE These are often conventional wellheads with several sections each having side outlets through which annular casing pressure can be measured and monitored unlike subsea wellheads.

3.48**sustained casing pressure****SCP**

Pressure between tubular strings that rebuilds after bleeding down, that cannot be attributed to applied pressure or thermal effects.

3.49**target pressure**

Intended pressure the annulus is bled down to during a diagnostic test.

NOTE 1 For surface wells, the target pressure can be as low as zero psig (kPa).

NOTE 2 For subsea wells, the target pressure can be as low as the hydrostatic pressure of the fluids in the annulus monitoring line(s) or flowline pressure.

3.50**test pressure**

Maximum internal pressure to which equipment can be exposed to ensure its ability to resist bursting.

NOTE The supplier/manufacture can provide both the test pressure, the RWP and performance ratings for wellhead and completion equipment.

3.51**thermally induced casing pressure**

Annular casing pressure as a result of thermal expansion of contained (or trapped) annular wellbore fluids (liquids, gas, or both).

3.52**tieback casing**

Casing that is run from the top of a liner back to the wellhead after the initial liner and hanger system have been installed.

NOTE 1 A tieback is normally used to provide a higher pressure rating than the existing casing string and can be cemented in place.

NOTE 2 A tieback annulus is typically designed to be isolated from the associated liner annulus.

3.53**true vertical depth****TVD**

The vertical distance from a point in the well to the horizontal plane at a reference datum.

3.54**tubing**

Retrievable tubular components of the completion string run inside the innermost casing/liner and tieback (if installed) to convey produced fluids (liquids, gas, or both) from the hydrocarbon-bearing formation to the surface or injected fluids from the surface to the formation.

3.55**tubing hanger**

A device that provides mechanical support for the tubing in the wellhead and seals between the tubing and the production casing in the wellhead just below the tree.

3.56**well integrity**

A quality or condition of a well having mechanical isolation with an effective barrier envelope to prevent unintentional flow of fluids (liquids, gas, or both) from one formation to another or to the wellhead.

3.57**well**

A drilled hole and a system of barrier elements consisting of steel tubulars, cement, a wellhead, and other components intended to function as a conduit to safely contain and transmit formation fluids (liquids, gas, or both) from a subsurface reservoir to the wellhead or to inject fluids into a subsurface interval.

3.58**zonal isolation**

The prevention of unwanted flow between two or more formations by installation and verification of a well barrier or a well barrier element.

4 Sources and Types of Annular Casing Pressure

4.1 General

Annular casing pressure (ACP) is generally classified as sustained casing pressure (SCP), thermally induced casing pressure, or operator-imposed pressure. Typical annuli naming nomenclature is illustrated in Figure 1 and Figure 2.

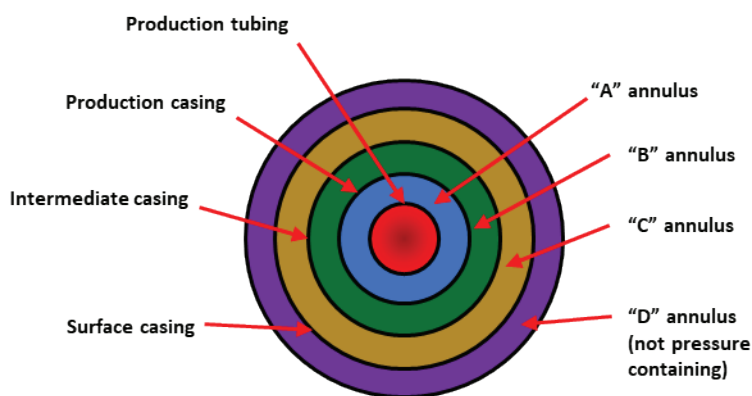


Figure 1—Typical Annuli Naming Convention

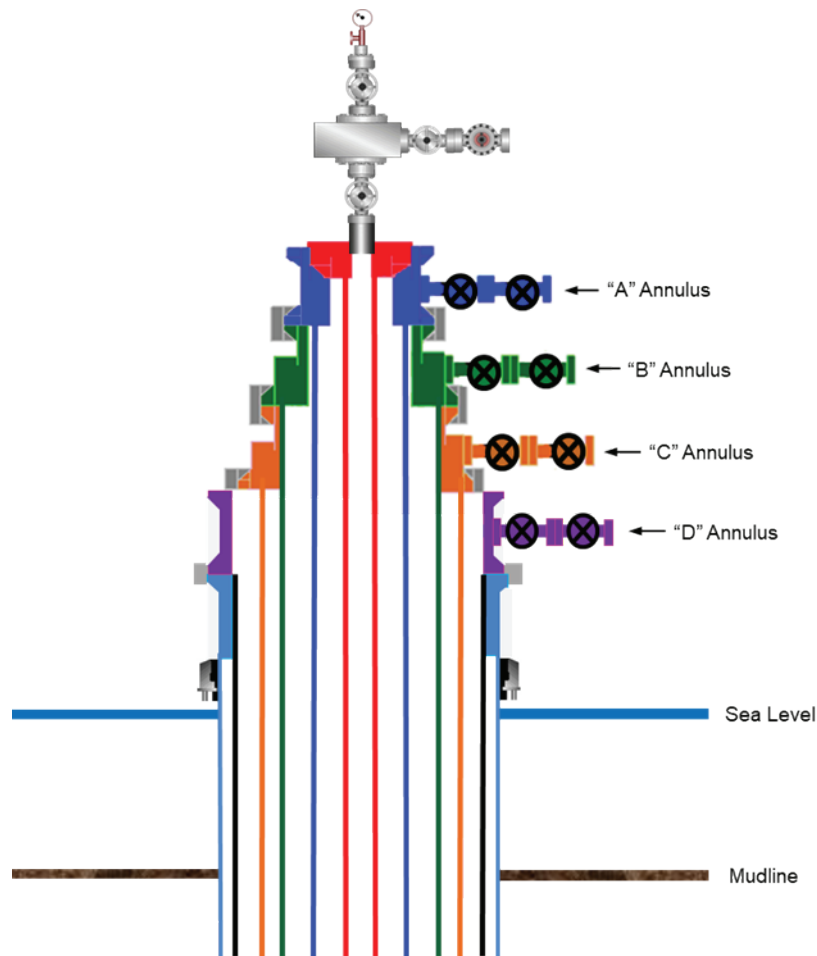


Figure 2—Typical Annuli Naming Convention

The identification of potential SCP source zones is normally from data collected before or during well drilling and includes the following:

- focused seismic surveys that identify shallow gas hazards or the presence of hydrates;
- logging-while-drilling (LWD), measurement-while-drilling (MWD), pressure-while-drilling (PWD), and electric-line formation evaluation logs;
- mud logger data, such as units or percent gas-cut mud, density of gas-cut returned mud, hydrocarbon sample analysis, etc.;
- formation flow tests and fluid/pressure sampling wireline tool data.

When the pressure source is the producing formation or other formations capable of providing pressured hydrocarbons, the risks are normally considered to be higher than when the pressure source is a formation not capable of producing pressured fluids (i.e. low permeability formations). This consideration is because of the formation's relatively high pressure and its ability to sustain hydrocarbon flow over a long period of time versus other formations that may have either high or low pressure, but generally have only limited capacity to sustain flow over a long period of time.

4.2 Sustained Casing Pressure

4.2.1 General

SCP is usually the result of a compromised barrier element(s) that permits the flow of fluid across a primary or secondary barrier envelope. The source of SCP can be any pressurized formation, including a hydrocarbon-bearing formation, water-bearing formation, shallow gas zone, shallow water zone or gas of biogenic origin.

4.2.2 SCP in the “A” Annulus

The producing formation is often the source of SCP in the “A” annulus because of a leak in completion equipment, which allows flow from the producing formation directly into the “A” annulus. Although it is less common, “A” annulus SCP can also result from a leak in the production casing above the packer.

4.2.3 SCP in Outer Annuli

Non-producing formations, including hydrocarbon-bearing zones, shallow water zones, shallow gas zones, etc., may be the source of SCP in the outer casing annuli. Outer annulus SCP usually indicates a loss of well integrity or annular fluid hydrostatic underbalance. Annular fluid density typically decreases as mud solids settle and filtrate seeps into adjacent formations. Outer annuli SCP can also be caused by the failure of the cement job to isolate a pressure source from the annulus or result from flow from an inner annulus to an outer annulus.

4.3 Thermally Induced Casing Pressure

Thermally induced casing pressure is the result of thermal expansion of trapped well fluids usually caused by the differential temperature between static conditions and dynamic conditions. Thermal induced casing pressure is also affected by production rate changes and changes in fluid composition. This pressure may be bled off or it may remain depending upon the well design or operator’s philosophy. The pressure will not rebuild if the well is at thermal equilibrium.

4.4 Operator-imposed Pressure

An operator may intentionally place pressure inside a casing annulus for various purposes, including gas lift, thermal management, to assist in monitoring (i.e. trapping pressure) within the annulus, or for other purposes.

5 Offshore Well System Overview and Operational Considerations

5.1 Well System Overview

5.1.1 General

Four basic well types are discussed with the variations between designs contributing to the ability to monitor individual annuli for pressure over the life of the well. These are

- surface well,
- subsea well,
- hybrid well, and
- mudline suspension well.

Each well type has been selected for a particular purpose. The equipment needed for sealing annuli or providing monitoring points depends upon the well’s location and use. For example, wells can be drilled in shallow water and tied back to a fixed platform with the wellhead and surface tree above the water line. The use of a subsea wellhead can prevent outer casing annuli from being monitored. If a mudline suspension system is used, the

outer casing annuli may be accessible for monitoring depending upon the number of casing strings tied back to the platform.

These are typical arrangements for casing, tubing, and wellheads, but there are many variations. These are used only as examples of individual well configurations.

5.1.2 Well Configuration Overview

5.1.2.1 General

Components of each well category are listed below along with design features that can impact monitoring and diagnostic analysis for annular casing pressure.

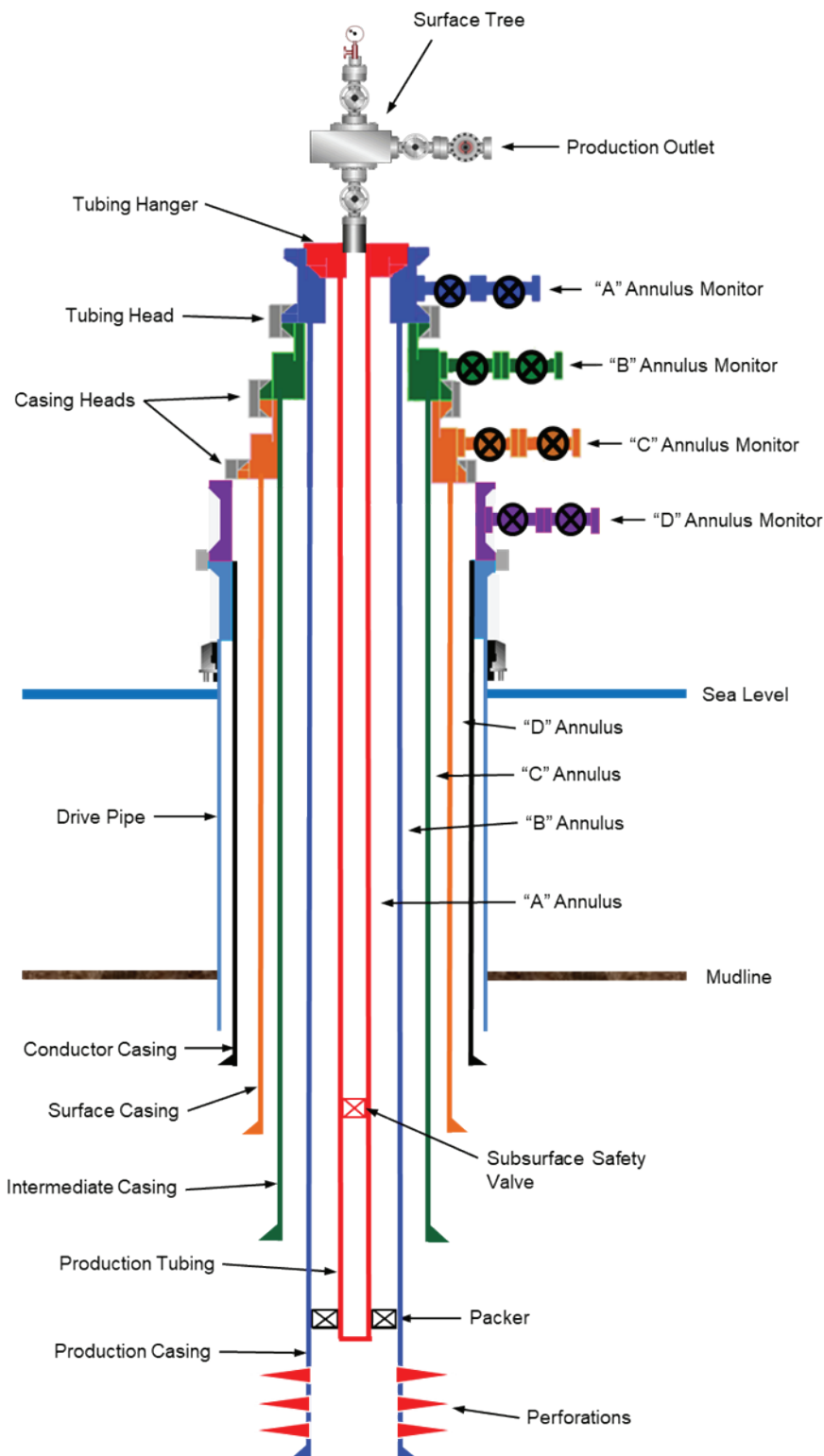
5.1.2.2 Surface Wells

The surface wellhead is typically composed of casing heads that suspend the weight of the casing strings and seal the top of the casing annulus at the casing head (see Figure 3). Because each casing string is typically set in a separate wellhead spool or bowl, access to each annulus should be available through a side outlet valve. This provides a means to monitor casing pressure and to bleed or inject fluids. These wellhead components are widely used on fixed platform wells and are almost identical to most onshore wellheads.

Unitized or multi-bowl wellheads may be used for fixed platform wells. The functions and design requirements described above are also met by these wellhead types. Each annulus should be accessible through a side outlet valve.

The tubing head suspends the weight of the tubing, provides a seal at the top of the “A” annulus, provides sealed outlets for control lines and monitoring points, and provides access to the “A” annulus for bleeding pressure or injecting fluids.

The surface tree is typically mounted on the tubing head and includes master valves, swab valve(s) and production outlets.



5.1.2.3 Subsea Wells

The subsea wellhead consists of several major components as follows (see Figure 4).

- a) A low-pressure wellhead housing connected to and installed with the structural (conductor) casing string. This housing provides some low-pressure containment capability, is primarily used for structural support for the well, and serves as the landing point for installing the high-pressure wellhead housing.
- b) A high-pressure wellhead housing, which is a thick-walled pressure vessel, is typically connected to and installed on the surface casing. It has external grooves to lock the BOP or subsea tree connector to the housing, and internal profiles to land and lock the casing hangers and packoffs. The high-pressure housing usually lands and locks to the low-pressure wellhead housing to gain structural support from the conductor. The high-pressure housing has the mechanical and pressure capacity to withstand the highest expected well pressure during well drilling, completion, and production operations.
- c) Subsea casing hangers and packoffs individually suspend and seal intermediate and production casing strings in a stacked arrangement inside the unitized high-pressure wellhead housing.

The upper end of the subsea well is terminated with a subsea tree and a subsea tubing hanger. The tubing hanger suspends the production string, sealing off the “A” annulus, providing direct vertical access into the production string and isolating pressure access into the “A” annulus.

The production casing string uses the last casing hanger assembly in the wellhead housing and allows direct access to the “A” annulus. The subsea tubing hanger (and/or subsea tubing head) isolates this cavity but typically provides a nominal bore access between the subsea tree into the annulus below.

The subsea tree is connected to the high-pressure wellhead housing with an external connector that provides pressure-containing conduits; one for direct vertical access to the production string, the second for access to the “A” annulus. The “A” annulus and production string are connected with a crossover loop and valve so that annulus pressure can be vented to the production flow line when needed. Electronic pressure transducers may be located downstream of the annulus master valve for monitoring pressure in the “A” annulus.

For completed subsea wells, the only annulus available for monitoring casing pressure is typically the “A” annulus because the casing strings are terminated and sealed inside the subsea wellhead.

Wells awaiting completion cannot be monitored.

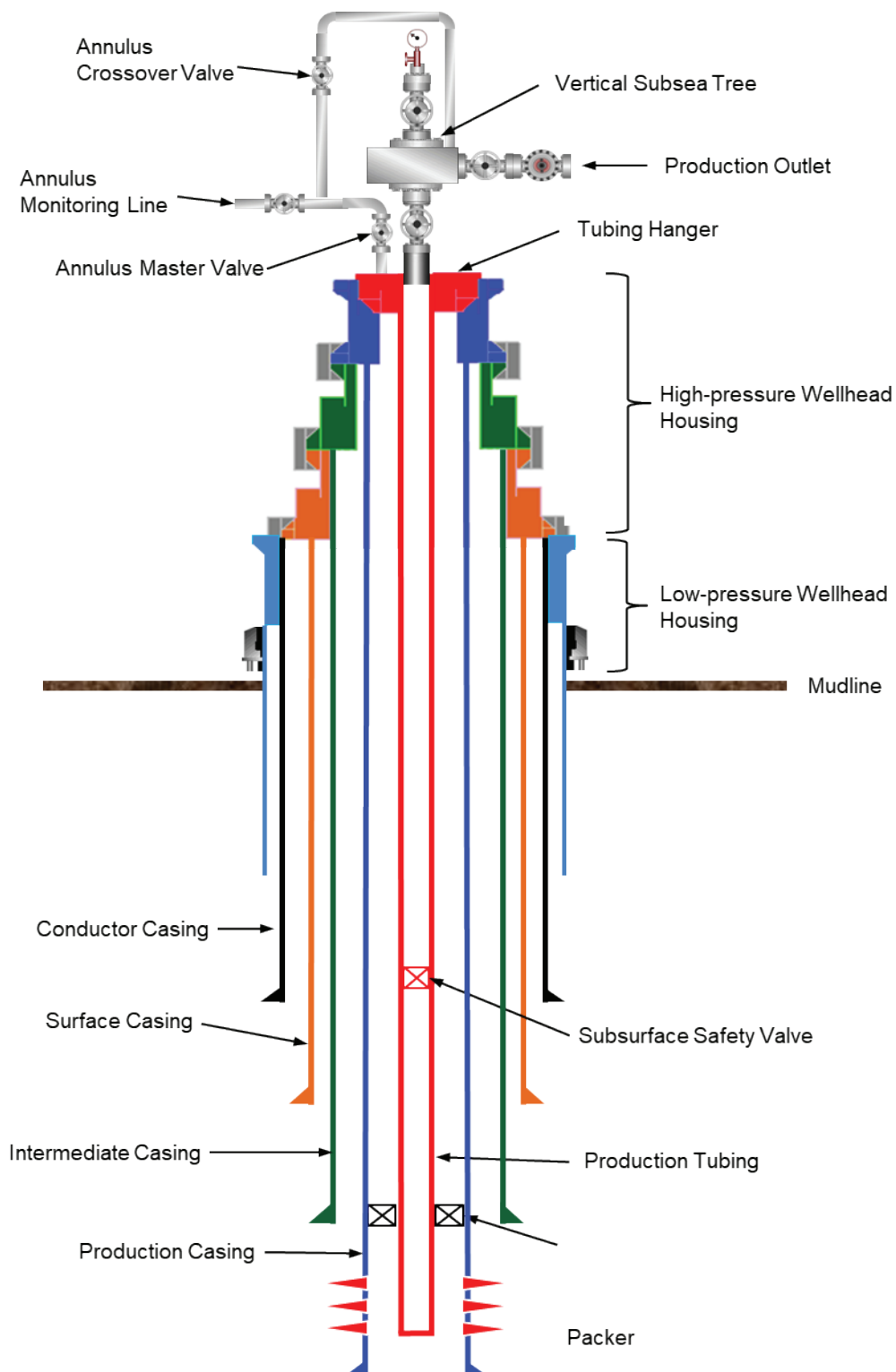


Figure 4—Vertical Subsea Well with “A” Annulus Access and Upstream Crossover without a Tubing Head

5.1.2.4 Hybrid Well

A hybrid well has a subsea wellhead, a surface tree, a surface casing head, spool or tubing head (or both), and single or dual bore production riser connecting the subsea wellhead to the surface platform (see Figure 5).

Mudline isolation packers may be used. If a mudline isolation packer is installed, this will isolate the production riser from the annulus below the packer.

The production riser(s) is connected to the subsea wellhead with a tieback connector. The inner production riser of a dual bore production riser system may be connected to the subsea wellhead or to a liner suspended deeper in the well than the subsea wellhead.

The production riser(s) may be supported by tensioners, buoyancy cans, a combination of methods, or by the platform jacket guides and deck structure. The surface casing head installed at the upper end of the production riser(s) provides a hang-off point for the production riser(s) and tubing string(s). It also provides the structural and pressure-containing connection point for the surface production tree.

The "A" annulus is the only annulus available for monitoring on a single-bore hybrid riser system since the other casing annuli are terminated in the subsea wellhead. On a single-bore hybrid riser system, if a mudline isolation packer is installed, both the production riser and the "A" Annulus are available to be monitored independently of one another. For hybrid wells with a dual bore production riser, the outer production riser annulus is also available for monitoring along with the "B" annulus, absent a mudline pack-off.

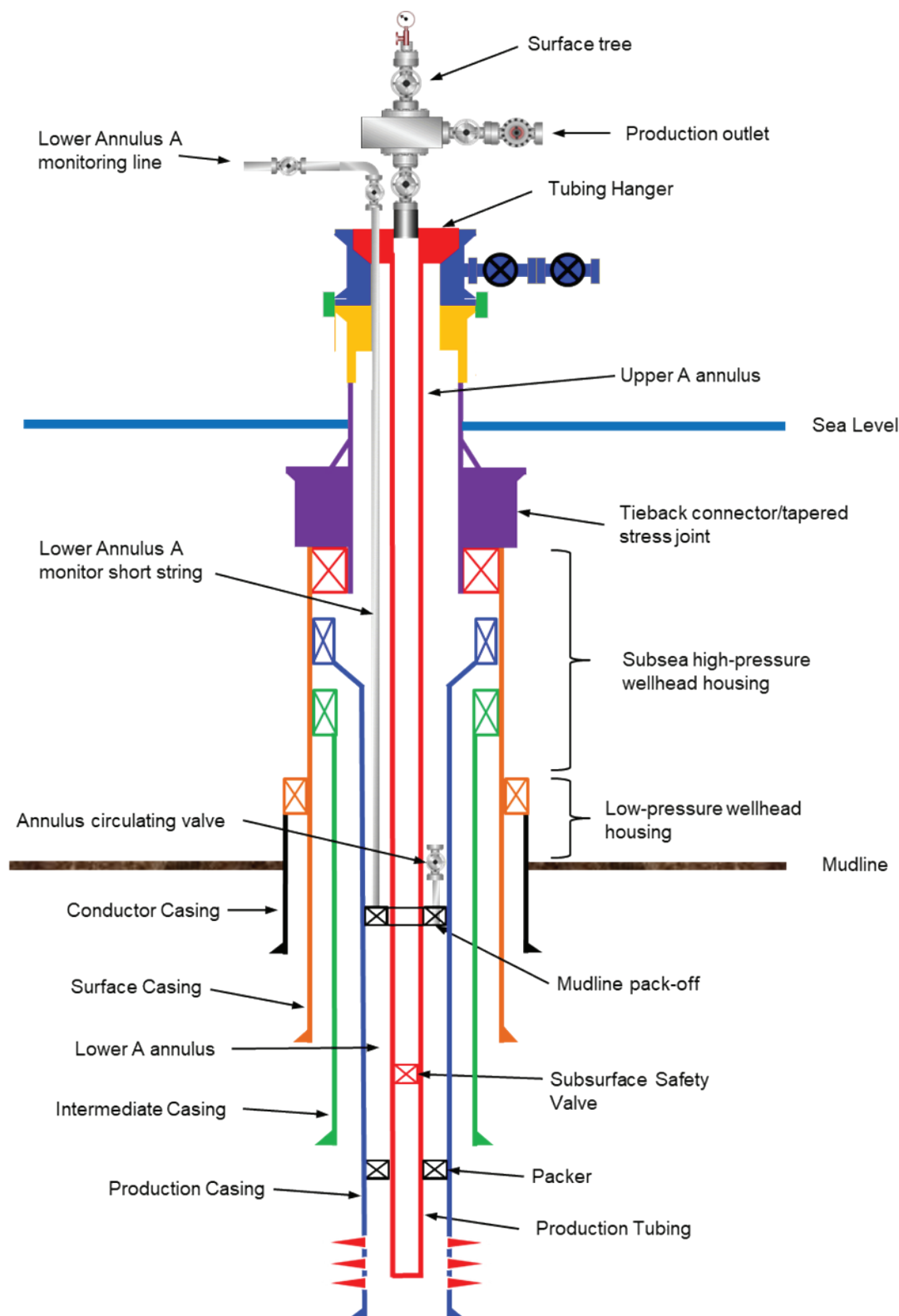


Figure 5—Single Bore Production Riser with Mudline Packoff without Gas Lift

5.1.2.5 Mudline Suspension Wells

The mudline suspension equipment (see Figure 6) supports the weight of each casing string from a load shoulder or multi-shoulder hanger. Mudline suspension hangers are designed to allow flow-by for the purpose of cementing and are not pressure sealing.

The mudline suspension well may be completed at the surface or subsea. For surface completions, the well uses a surface tree and wellhead that are tied back to the mudline suspension system. It is possible to tie back each casing string from the production to the surface casing, however, not all the casings are always tied back. The number of annuli available for monitoring depends on the number of casing strings tied back. A single annulus may be tied back to multiple casing annuli.

For subsea completions, the well uses a subsea tree and a subsea tubing head to suspend the tubing. Production is piped to the surface through a flow line directly from the tree or from a subsea separator. The "A" annulus is available for monitoring, and in few cases the "B" annulus is also available for monitoring. Monitoring is typically conducted via the annulus monitoring line in an umbilical. If required, pressure is also bled off through this line because these wells are generally not equipped with a crossover valve from the "A" annulus to the flowline.

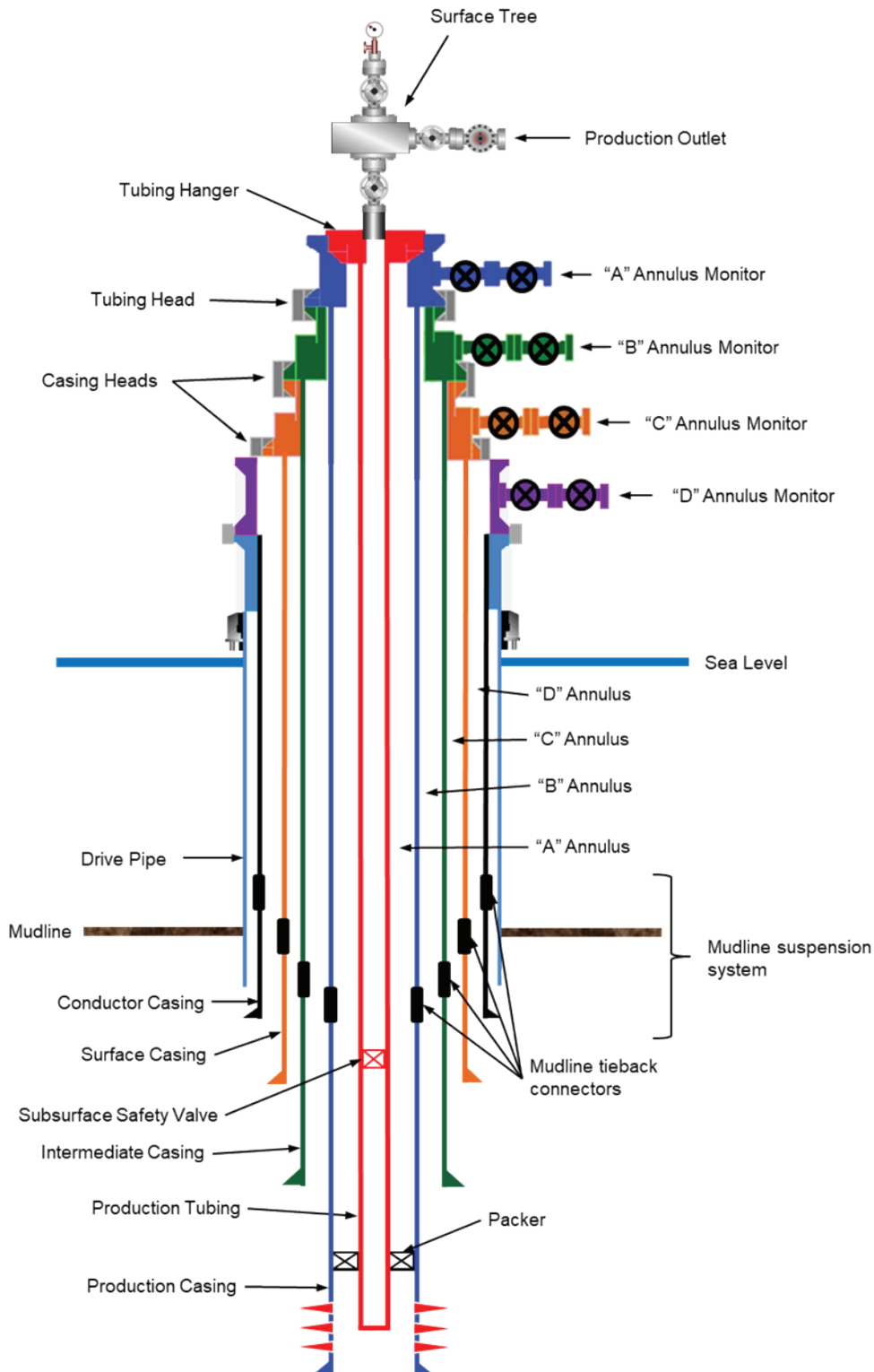


Figure 6—Four String Production Riser Tieback for a Mudline Suspension Well with Surface Tree

5.2 Potential Leak Paths in the "A" Annulus

5.2.1 General

The "A" annulus is available for monitoring in all four well types. In the subsea well and the hybrid well, it is typically the only annulus that can be monitored. Outer annuli for those casing strings tied back to the surface