

Annular Casing Pressure Management for Offshore Wells

API RECOMMENDED PRACTICE 90
FIRST EDITION, AUGUST 2006

REAFFIRMED, JANUARY 2012



AMERICAN PETROLEUM INSTITUTE

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Upstream Segment

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FOREWORD

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Suggested revisions are invited and should be submitted to the Standards and Publications Department, API, 1220 L Street, NW, Washington, DC 20005, standards@api.org.

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Recommended Practice for Annular Casing Pressure Management for Offshore Wells

1 General

1.1 SCOPE

This Recommended Practice is intended to serve as a guide for managing annular casing pressure in offshore wells. Although the prevention of annular casing pressure is very important, it is beyond the scope of this document. Prevention of annular casing pressure is planned to be addressed in API RP 65, Part 2. The remediation of wells because of sustained casing pressure is also beyond the scope of this document and is planned to be included in API RP 65, Part 3. This guide is meant to be used for offshore wells that exhibit annular casing pressure, including thermal casing pressure, sustained casing pressure (SCP) and operator-imposed pressure.

This Recommended Practice covers monitoring, diagnostic testing, the establishment of a maximum allowable wellhead operating pressure (MAWOP) and documentation of annular casing pressure for the various types of wells that occur offshore. Included also is a discussion of risk assessment methodologies that can be used for the evaluation of individual well situations where the annular casing pressure is not within the MAWOP guidelines.

This Recommended Practice recognizes that annular casing pressure results in various levels of risk to the safety of personnel, property and the environment. The level of risk presented by annular casing pressure depends on many factors, including the design of the well and the source of the annular casing pressure. This Recommended Practice provides guidelines in which a broad range of casing annuli that exhibit annular pressure can be managed in a routine fashion while maintaining an acceptable level of risk. Annular pressures that do not conform to the guidelines in this Recommended Practice may still have an acceptable level of risk, but they need to be evaluated on a case-by-case basis.

This Recommended Practices establishes an acceptable level of risk for annular casing pressure using three parameters. First, annuli that exhibit annular casing pressure of 100 psig or less present little risk and should be monitored. Second, annular casing pressure that is greater than 100 psig and that has been diagnosed as sustained casing pressure (SCP) must bleed to zero psig. Third, a Maximum Allowable Wellhead Operating Pressure (MAWOP) is established for each non-structural casing annulus that exhibits annular casing pressure, including thermal casing pressure, sustained casing pressure or operator-imposed pressure. If the annular casing pressure does not meet the criteria established in this Recommended Practice, this does not mean that the risk presented by the annular pressure is unacceptable. Rather, it indicates that the annular casing pressure needs to be managed on a case-by-case basis that goes beyond the scope of this Recommended Practice. The case-by-case management of annular casing pressure may include the use of risk assessment techniques. Techniques that may be used for case-by-case risk assessment are discussed in Section 10 of this Recommended Practice. In some cases, the annular casing pressure may need to be reduced or eliminated by well work. In other cases, the risk may be mitigated by other methods. Procedures for eliminating annular casing pressure or mitigating the risk are beyond the scope of this Recommended Practice.

1.2 DOCUMENT ORGANIZATION

Regarding annular casing pressure, this Recommended Practice has general information that is applicable to all offshore well types. For each of the well types covered by this Recommended Practice, fixed platform wells, subsea wells, hybrid wells and mudline suspension wells, a section for each well type has been provided in which complete information is given for that well type. While in many cases this is redundant information, it allows the user of the Recommended Practice to go to the section for the applicable well type and review all of the information in one section.

1.3 DEFINITIONS

1.3.1 “A” Annulus: The annulus designation between the production tubing and production casing.

1.3.2 ambient pressure: Pressure external to the wellhead. In the case of a surface wellhead, it would be zero psig. In the case of a subsea wellhead, it would be equal to the hydrostatic pressure of seawater at the depth of the subsea wellhead in psig.

1.3.3 “B” Annulus: The annulus designation between the production casing and next outer casing. The letter designation continues in sequence for each and every outer annular space encountered between casing strings up to and including the surface casing and conductor casing strings.

1.3.4 barrier elements: One or several dependent objects, i.e., packers, tubing, or casing, preventing formation fluids from flowing unintentionally into another formation or to the surface.

1.3.5 conductor casing: Provides structural support for the well, wellhead and completion equipment, and often provides hole stability for initial drilling operations. This casing string is not designed for pressure containment, but upon completion of the well, it may have a casing head; therefore, it may be capable of containing low annular pressures. This casing is set prior to encountering any hydrocarbons at a depth where the fracture gradient will allow for an increase in mud density and is cemented to the surface or mudline. For subsea and hybrid wells, the low pressure subsea wellhead is normally installed on this casing string.

1.3.6 diagnostic testing: Tests or techniques performed to evaluate the existence of annular casing pressure, and in some cases, to attempt to determine the source of the annular casing pressure. Included are bleed-down/build-up tests, evaluation of fluids and volumes from bleed-down tests, evaluation of real-time accessible pressure data, production logs, operational observations, etc.

1.3.7 drive/jet pipe: Supports unconsolidated deposits and provides 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.

1.3.8 fixed platform wells: Wells completed with a surface wellhead and a surface tree on a fixed platform. All of the casing strings are tied back to the surface wellhead.

1.3.9 hybrid wells: Wells drilled with a subsea wellhead and completed with a surface casing head, a surface tubing head, a surface tubing hanger, and a surface christmas tree. A hybrid well may have either one (single bore production riser) casing string or two (dual bore production riser) casing strings brought up from the subsea wellhead and tied back to the surface equipment. These wells are typically located on floating production platforms such as spars or TLPs.

1.3.10 intermediate casing: Casing that is set when geological characteristics or wellbore conditions indicate downhole protection is needed or to prevent lost circulation by casing off weaker formations. Multiple intermediate casing strings can be run in a single well.

1.3.11 liner casing: A casing string suspended near the bottom end of a previous casing string using a liner hanger.

1.3.12 Maximum Allowable Wellhead Operating Pressure (MAWOP): The maximum allowable operating pressure for a particular annulus, measured at the wellhead relative to ambient pressure. It applies to SCP, thermal casing pressure and operator-imposed casing pressure.

1.3.13 mudline packoff or packer: An upper packer run on the production tubing and set in the production casing below the mudline wellhead to isolate the production riser section from the production casing. This configuration is common in hybrid wells.

1.3.14 mudline suspension system: A casing suspension system that allows a well to be drilled using a surface BOP, surface wellhead and surface drilling equipment. The mudline suspension equipment provides for individual casing hangers to be installed with each casing string that interconnects with each other at a preset point below the mudline. The mudline suspension casing hangers do not provide a pressure barrier. After the well is drilled and cemented, these casing hangers allow for the removal of the casing string between the casing hanger and the surface wellhead. After these strings are removed, a cap can be placed over each casing string, isolating each casing string and the annular space between it and the previously capped casing string inside, at the casing hanger interface. These wells are tied back prior to the well completion in one of two methods:

1. Individually connecting two or more tie-back casing production riser strings back to a surface casing head, tubing head/tubing hanger, and christmas tree (mudline surface well). Each string has its own tie-back connector, which provides a structural and pressure-containing connection between the casing strings below the mudline and the tie-back casing production riser string from the seafloor up to the surface. See Figure 13.1.3 in Appendix C.
2. Individually connecting two or more tie-back casing strings back to a subsea tubing head, using individual tie-back connectors, followed by the installation of a subsea tubing hanger and subsea tree (mudline conversion well or mudline subsea well). See Figures 13.4.1 through 13.4.9 in Appendix C.

1.3.15 mudline suspension wells: A well drilled using a mudline suspension system and a surface blowout preventer (BOP). The mudline suspension well may be completed as either a surface well or as a subsea well.

1.3.16 operator-imposed casing pressure: Casing pressure that is operator-imposed for purposes such as gas lift, water injection, thermal insulation, etc.

1.3.17 production casing: Casing that is the innermost string of casing in the well. Production fluids enter the casing below the production packer and continue to the surface through the production string. At a minimum, the production casing will be rated for the maximum anticipated pressure that may be encountered from the production zone.

1.3.18 primary well barrier: First set of barrier elements that prevents flow from a source.

1.3.19 production liner: A liner that is the innermost string in which the productive zones are completed. The casing in which the production liner is hung off is usually referred to as the production casing.

1.3.20 production riser: The casing strings rising from the seafloor to the wellhead on fixed platforms, or the casing strings attached to the subsea wellhead rising from the seafloor to the surface wellhead on hybrid wells.

1.3.21 production string (or completion string): The production string consists primarily of production tubing, but also includes additional components such as the surface-controlled subsurface safety valve (SCSSV), gas lift mandrels, chemical injection and instrument ports, landing nipples, and packer or packer seal assemblies. The production string is run inside the production casing and used to conduct production fluids to the surface.

1.3.22 production tubing: Tubing that is run inside the production casing and used to convey produced fluids from the hydrocarbon-bearing formation to the surface. Tubing may also be used for injection. In hybrid wells, for example, tubing is used as a conduit for gas for artificial lift below a mudline pack-off tubing hanger to isolate the gas lift pressure from the production riser.

1.3.23 secondary well barrier: Second set of barrier elements that prevents flow from a source.

1.3.24 structural pipe casing strings: Casing strings used to facilitate the drilling of the well, but not needed for pressure containment after the well has been drilled. Support unconsolidated sediments and provide hole stability for initial drilling operations, axial support for casing loads and bending loads from the subsea wellhead.

1.3.25 subsea wells: Wells completed with a subsea wellhead and a subsea tree.

1.3.26 subsea wellhead: A wellhead that is used with a floating drilling rig that uses a subsea BOP stack for well control. The subsea wellhead is usually connected to the surface casing string and all subsequent casing strings are installed, landed, and sealed inside the subsea wellhead's high pressure housing, immediately below the BOP. The well can be completed in one of two methods:

1. Using a subsea tree (subsea well).
2. Using one or two production risers leading back to a surface casing head, tubing head/tubing hanger, and christmas tree (hybrid well).

1.3.27 surface casing: Casing run inside the conductor casing to protect shallow water zones and weaker formations and may be cemented within the conductor string and is often cemented back to the mudline. The surface wellhead is normally installed on this string for surface wells.

1.3.28 surface well: A well completed on the surface with individual casing heads, tubing head, a surface tubing hanger, and a surface christmas tree, all residing at a designated level above the water line on a fixed platform.

1.3.29 Sustained Casing Pressure (SCP): Pressure in an annulus of non-structural casing strings that is:

1. measurable at the wellhead of a casing annulus that rebuilds to at least the same pressure level when bled down;
2. not caused solely by temperature fluctuations; and
3. not a pressure that has been imposed by the operator.

1.3.30 thermal casing pressure: Pressure generated within a sealed annulus by thermal expansion of trapped wellbore fluids during production.

1.3.31 well barrier: Envelope of one or several dependent barrier elements preventing fluids or gases from flowing unintentionally from the formation into another formation or to the surface.

1.3.32 well integrity: Application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well.

1.4 REFERENCED DOCUMENTS

API

Bull 5C3/ISO 10400	<i>Bulletin on Formulas and Calculations for Casing, Tubing, Drill Pipe and Line Pipe Properties</i>
Spec 5CT/ISO 11960	<i>Specification for Casing and Tubing</i>
Spec 17D/ ISO 13624-4	<i>Subsea Wellhead and Christmas Tree Equipment</i>
RP 65	<i>Cementing Shallow Water Flow Zones in Deepwater Wells</i>
RP 65, Part 2 (working draft)	<i>Prevention of Flow After Cementing and Sustained Casing Pressure</i>

2 Source of Pressure

Annular casing pressure is generally classified as SCP, thermal casing pressure, or operator-imposed casing pressure.

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

- LWD/MWD and electric line formation evaluation logs
- Mud logger data, such as units of gas-cut mud, hydrocarbon sample analysis, etc.
- Formation test and fluid sampling tool data

When the pressure source is the producing formation or formations capable of sustained hydrocarbon production, the risks are normally considered to be higher than when the pressure source is a formation not capable of sustaining production. This is because of a production formation's relatively high pressure and its ability to sustain 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.

2.1 THERMALLY INDUCED PRESSURE

Thermally induced casing pressure is the result of thermal expansion of trapped wellbore fluids usually caused by the differential temperature between static conditions and producing conditions when production is initiated. All wells will exhibit thermal casing pressure when the well is initially brought on production. This pressure may be bled off or it may remain, depending on the well design or operator's philosophy.

2.2 OPERATOR-IMPOSED PRESSURE

An operator may impose pressure on a casing annulus for various purposes, including gas lift, thermal management, to assist in monitoring pressure within the annulus, or for other purposes.

2.3 SUSTAINED CASING PRESSURE (SCP)

SCP is usually the result of a well component leak that permits the flow of fluid across a well control barrier, e.g., tubing connection leak, packer leak, etc., or because of uncemented (or poorly cemented) formations or damaged cement. The source of SCP may be any pressurized formation, including a hydrocarbon-bearing formation, water-bearing formation, shallow gas zone, shallow water zone or of biogenic origin.

2.3.1 SCP in the "A" Annulus

The producing formation is often the source of SCP in the "A" annulus because of a leak in the production string, which allows flow from the tubing string bore into the "A" annulus. Although it is less common, "A" annulus SCP can also result from a production casing leak.

2.3.2 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 the annular fluid hydrostatic overbalance. Annular fluid density typically decreases as mud solids settle and filtrate seeps into adjacent formations. SCP in the outer annuli can also result from flow from an inner annulus to the outer annulus.

2.4 MONITORING

All annuli capable of being monitored in a well should be routinely monitored for casing pressure. The frequency of monitoring should be determined after considering the well design, the presence of annular pressure, operator-established procedures and governmental agency requirements or guidance for establishing monitoring frequencies.

After annular pressure has been detected or observed, the operator should determine the appropriate diagnostic testing program for the well.

2.5 DIAGNOSTIC TESTING

The objective of diagnostic testing is to learn as much as practicable concerning the observed pressure. This includes the type of pressure (thermal, SCP, combination, etc.). It may also be helpful in the identification of the magnitude of a leak in a well control barrier. These procedures range from measurement of pressures in the available annuli to mathematical analysis of pressure changes, such as SCP build-up curves or bleed-down curves. Measurement of annular pressures can demonstrate that well control barriers are competent or that additional diagnostics may be required. Some of these diagnostic procedures are the following:

1. Monitor magnitude and changes in pressures of each available annulus.
2. Change pressure to determine if pressure is thermally induced. Thermally induced pressure will bleed down and remain relatively constant, whereas SCP caused by a leak across a well control barrier will allow the pressure to build back.
3. Close SCSSV (or set tubing plug), bleed off surface tubing pressure and observe the “A” annulus pressure to determine if the tubing leak is above or below SCSSV or tubing plug.
4. Change pressure in one annulus and observe changes in adjacent annuli.

3 Annular Casing Pressure Management Program

This Recommended Practice is based on establishing an annular casing pressure management program whereby non-problematic wells that present an acceptable level of risk are filtered out with a minimum of knowledge and effort, thus allowing for a more focused effort on wells that are increasingly more problematic. The management program should include all types of annular casing pressure, including SCP, thermal casing pressure and operator-imposed casing pressure. The management program should include the following elements:

- monitoring program;
- diagnostic testing program;
- determining MAWOP for each annulus;
- documentation;
- risk assessment considerations.

The annular casing pressure management program is based on the following principles:

- The same level of safety should be maintained as historical prescriptive methods have provided.
- The primary concern with annular pressure is related to the potential for loss of well control either at the surface or subsurface.
- SCP is an indication that the well system has a leak.
- Most leaks are a result of a combination of minor defects and events rather than exceeding the design specifications of the well system.
- Not all annular casing pressure represents a significant increase in risk.
- An acceptable level of risk can be established for a large number of annuli by using criteria that require a minimum amount of knowledge and effort.
- Annuli that do not meet an acceptable level of risk as established in this Recommended Practice should be evaluated on a case-by-case basis.
- All monitoring and diagnostic testing should be properly documented.

An acceptable level of risk caused by annular casing pressure is established in this Recommended Practice by three parameters. First, wells that exhibit 100 psig or less of annular casing pressure present little risk and should just be monitored. Second, annular casing pressure greater than 100 psig that has been diagnosed as SCP must bleed to zero psig. SCP that will bleed to zero psig presents an acceptable risk to personnel, property and the environment, since it indicates that the leak rate is small and the barriers to flow are still effective. The third parameter establishes a Maximum Allowable Wellhead Operating Pressure (MAWOP), in which the maximum annular pressure allowed on the annulus is determined. The MAWOP calculation is applicable to SCP, thermal casing pressure and operator-imposed casing pressures. The establishment of the MAWOP for an annulus presents an acceptable risk posed by annular pressure to personnel, property and the environment since it minimizes the risk of burst or collapse of the tubulars.

If the annular casing pressure does not meet the criteria established by the three parameters discussed above, this does not mean that the risk presented by the annular pressure is unacceptable. Rather, it indicates that the annular casing pressure needs to be managed on a case-by-case basis that goes beyond the scope of this Recommended Practice. The case-by-case management of annular casing pressure may include the use of risk assessment techniques, which are discussed in Section 10 of this Recommended Practice.

Appendix A of this document contains simple flow charts of the annular casing pressure management program, as well as examples for each well type.

4 Maximum Allowable Wellhead Operating Pressure (MAWOP)

The Maximum Allowable Wellhead Operating Pressure (MAWOP), as defined in 1.3, is a measure of how much pressure can be safely applied to an annulus and is applicable to all types of annular pressure, including thermal casing pressure, SCP and operator-imposed pressure. The MAWOP is measured relative to the ambient pressure at the wellhead for any particular annulus. It establishes a safety margin in consideration of the following failure modes:

- Collapse of the inner tubular.
- Burst of the outer tubular.

The MAWOP for the annulus being evaluated is the lesser of the following:

- 50 percent of the Minimum Internal Yield Pressure of the pipe body for the casing or production riser string being evaluated; or
- 80 percent of the Minimum Internal Yield Pressure of the pipe body of the next outer casing or production riser string; or
- 75 percent of the Minimum Collapse Pressure of the inner tubular pipe body.

For the last casing or production riser string in the well, the MAWOP is the lesser of the following:

- 30 percent of the Minimum Internal Yield Pressure of the pipe body for the casing or production riser string being evaluated; or
- 75 percent of the Minimum Collapse Pressure of the inner tubular pipe body.

The Minimum Internal Yield Pressure (MIYP) and the Minimum Collapse Pressure (MCP) for the tubing and casing strings can be calculated according to API Bulletin 5C3. When casing, production riser, or tubing strings are composed of two or more weights or grades, the minimum weight or grade should be used in the MAWOP calculation.

For the MAWOP calculation, a safety factor expressed as a percent of the MIYP of the pipe body has been used. The safety factor takes into account the following considerations:

- The minimum pressure rating of other elements within the casing string, such as couplings, threads, rupture disks, etc.
- Unknown erosion or corrosion of the pipe.
- Unknown casing wear.
- Unknown age effects.

For the MAWOP calculation, a safety factor of 50 percent of the MIYP of the pipe body has been used for the casing or production riser string being evaluated as a reasonable and conservative risk of bursting the pipe. A higher percentage (80%) of the MIYP is allowed for the next outer casing or production riser string than for the casing or production riser string being evaluated,

since this would be considered an extreme load and higher utilization factors are typically allowed for extreme load cases. A lower percentage of the MIYP (30%) is allowed for the last outer casing or production riser string, since it is the last barrier.

If a casing string has significant rotating time, suspected or known erosion or corrosion, or is operating under high temperature, then the operator should consider applying a de-rating factor to the wall thickness or material properties in calculating the MIYP.

In most cases, the MAWOP will be established by either 50 percent of MIYP of the casing string being evaluated or by 80 percent of the MIYP criteria of the next outer casing string. However, the collapse pressure of the tubular within the annulus being evaluated should be considered, since collapsing the inner tubular is an undesirable event. For the MAWOP calculation, a safety factor of 75 percent of the MCP provides a reasonable and conservative measure of the risk of collapsing the inner tubular.

In some cases, pressure communication between the “A” and “B” annuli can exist, normally because of either a leak in the production casing string or in the wellhead. In these cases, the MAWOP formula is not applicable and these wells should be evaluated on a case-by-case basis.

If there is pressure communication between two or more outer casing annuli (e.g., communication between the “B” and “C” annuli or between the “C” and “D” annuli, etc.); then the casing separating these annuli is not considered a competent barrier and should not be used in the MAWOP calculation. See Appendix B for example calculations.

Example MAWOP calculations for each well type are shown in Appendix B. Examples of the annular casing pressure management program using the MAWOP calculations are shown in Appendix A.

5 Fixed Platform Wells

5.1 SYSTEM OVERVIEW

5.1.1 Typical Well Schematic

As defined in Section 1.3, a fixed platform well is characterized as having a surface wellhead and Christmas tree with all the casing strings tied back to the surface wellhead. Typical well schematics are shown in Appendix C.

5.1.2 Key Component Overview

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. Access to each annulus should be available at each casing head, which provides a means to monitor casing pressure and to bleed or to inject fluids.

The tubing head suspends the weight of the tubing, provides a seal at the top of the “A” annulus and provides access to the “A” annulus for monitoring casing pressure, as well as bleeding or injecting fluids.

Unitized or unihead wellheads may also be used for fixed platform wells. The functions and design requirements described above are also met by these types of wellheads.

The christmas tree is typically mounted on the tubing spool, which seals to the tubing string and provides sealed outlets for control and monitoring lines. The christmas tree includes the master, production and swab valves.

5.1.3 Potential Leak Paths in the “A” Annulus

The potential leak paths into the “A” annulus include the following:

- A cement seal integrity failure in the “B” annulus combined with a casing leak in the production casing string.
- Uncemented section in the “B” annulus combined with a casing leak in the production casing string.
- Production tubing connection leak.
- Hole in production tubing or parting of the production tubing string.
- Leak in gas lift mandrels, chemical injection mandrels, SCSSV and control lines.
- Production packer seal leak.
- Production casing hanger leak.
- Tubing hanger leak.

- Seal, penetrations, connection leaks in the christmas tree.
- Production casing collapse.
- Production liner top pressure integrity failure.

5.1.4 Potential Leak Paths in the Outer Annuli

- Cement seal integrity failure.
- Uncemented sections.
- Casing string leaks.
- Casing head packoff/seal leaks.
- Settling of annular fluid solids.

5.1.5 Design Considerations

5.1.5.1 Casing Strings

When first brought on production, all new wells with liquid packed annuli will normally exhibit a pressure increase caused by heating and the subsequent thermal expansion of the fluids. This annular pressure build-up is referred to as thermal casing pressure. This pressure may be bled off as the well is brought up to the operating temperature level. The outer casing string should be designed to withstand all potential thermal casing pressure. When practical, the design should also provide means for thermal casing pressure to be bled off. If thermal pressure is left on a casing string, it should be evaluated to ensure that it is not masking SCP.

5.1.5.2 Production String

The production string is the primary conduit for produced (or injected) fluids and it should be designed to withstand maximum anticipated pressures, temperatures and composition of fluids that it is expected to handle. The production string is normally considered to be the primary well barrier preventing uncontrolled flow from the producing formation. In many wells, the production string consists primarily of the production tubing. In other wells, the production string is more elaborate, with multiple potential leak paths such as control lines and mandrels. The production string is often the source of SCP in the "A" annulus because of connection leaks, erosion and corrosion of the connection or pipe body, or pipe body failure, such as collapse.

5.2 METHODS AND FREQUENCY OF MONITORING ANNULAR CASING PRESSURE

The following sections apply to producing wells, injection wells, shut-in wells and temporarily abandoned wells. They do not apply to newly drilled wells that are temporarily plugged and are pending the installation of production facilities, pipelines, etc.

Each non-structural casing string well annulus should be equipped so that casing pressure can be monitored either continuously or intermittently. Structural casings that are capable of containing pressure should also be monitored. Monitoring can be achieved by various methods including, but not limited to, the use of a Supervisory Control and Data Acquisition system (SCADA), a pressure pen recorder chart, installing appropriately scaled pressure gauges on each annulus to be monitored or equipping each annulus to be monitored such that a pressure gauge can be used when needed.

All monitoring should be documented in accordance with Section 9.

5.2.1 Routine Monitoring of Wells with No Casing Pressure

Each casing string well annulus capable of containing pressure should be monitored either continuously or periodically to determine if casing pressure is present in the annulus. The operator should establish the frequency of monitoring annuli that are currently not exhibiting casing pressure but, at a minimum, routine monitoring should occur at least once every six months. Should any casing annuli in a well have casing pressure, then all annuli in that well should be monitored at the same frequency established in accordance with 5.3.2, 5.3.3 and/or 5.3.4. The results of the monitoring should be documented in accordance with Section 9.

5.2.2 Monitoring of Wells with Sustained Casing Pressure (SCP)

The operator should establish the frequency of monitoring wells where one or more annuli have been diagnosed with SCP. The results of the monitoring should be documented in accordance with Section 9. At a minimum, routine monitoring of annuli with SCP should occur at least once every month. At a minimum, other annuli within the well that do not exhibit casing pressure should be monitored at the same frequency. The following factors should be considered in establishing the monitoring frequency:

- Platform is manned or unmanned.
- Magnitude of the observed pressure and casing yield/collapse pressure.
- The rate of pressure increase.
- Pressure communication across multiple annuli.
- Other annuli in the well have thermal casing or applied pressures.
- The pressure source.
- Location of platform with regard to sensitive environmental resources.
- Simultaneous operations at the platform.
- Potential risk to personnel and the environment.

5.2.3 Monitoring of Wells with Thermal Casing Pressure

During well startup, wells should be continuously monitored for indications of pressure caused by thermal expansion of fluids. This is especially important on new wells and wells where annuli have been liquid packed. A bleed-off plan should be established prior to startup.

The operator should establish the frequency of monitoring wells where one or more annuli have been diagnosed with thermal casing pressure. The results of the monitoring should be documented in accordance with Section 9. At a minimum, routine monitoring of annuli with thermal casing pressure should occur at least once every month. Wells that are producing with thermal casing pressure should be monitored following a choke change to increase production until the casing pressure stabilizes. At a minimum, other annuli within the well that do not exhibit casing pressure should be monitored at the same frequency.

The following factors should be considered in establishing the monitoring frequency:

- Platform is manned or unmanned.
- Magnitude of the observed pressure and casing yield/collapse pressure.
- Production characteristics of the well are stable.
- Annular pressure is stable.
- Other annuli in the well have SCP or applied pressures.

5.2.4 Monitoring of Wells with Operator-Imposed Pressures

Pressures that are applied by the operator should be monitored and documented in accordance with Section 9 relative to the activity requiring the applied pressure. At a minimum, routine monitoring of the annuli with applied pressure should occur at least once every month, and all other annuli in the well should be monitored in accordance with the timeframe established in 5.3.1, 5.3.2 and/or 5.3.3.

5.3 DETECTION OF PRESSURE

5.3.1 New Wells—Thermal Casing Pressure

All new wells or wells with liquid packed annuli will exhibit thermal casing pressure, which may be bled down as the well is initially brought on production. If any pressure is left on the annuli, it should be monitored for changes, according to 5.3.3, to ensure that it is not masking SCP.

5.3.2 Wells with Operator-Imposed Pressure

In some cases, the operator may deliberately apply pressure using nitrogen gas, natural gas or various liquids. Operator-applied pressures greater than 100 psig should be monitored for changes that may indicate a need for diagnostic testing. A typical bleed-

down and build-up diagnostic test may not provide a relevant evaluation of the “A” annulus in cases when there are large volumes of applied gases present in the annulus.

5.3.3 Potential Sustained Casing Pressure (SCP)

When pressure has been initially detected in an annulus (after the initial thermal casing pressure has been bled off or, if the pressure was not completely bled off, a change in pressure), the operator may consider verifying the validity of the pressure measurement observation by one or more of the following methods:

- Check the accuracy of the pressure gauge against a known pressure.
- Replace the pressure gauge with a different gauge.
- Recheck the pressure after several hours.
- Use a pen recorder to measure and record the pressure for a length of time, typically 12 to 24 hours.
- Verify utilizing a Supervisory Control and Data Acquisition (SCADA) system.

After the existence of pressure has been verified, records and well history should be gathered and reviewed to assist in determining the potential cause or source of the pressure.

- Check all other casing annuli pressures.
- Review previous monitoring records for any changes in pressure.
- Review well history for changes in production rate (oil, gas or water) or changes in flowing tubing pressure or changes in choke sizes or variations in applied pressure.
- Review drilling records, electric logs, mud log records, etc.

In addition, the MAWOP as discussed in Section 4 for each annulus should be calculated if it has not been previously established.

5.4 ANNULAR CASING PRESSURE EVALUATION TESTS

For new wells, the observed annular pressure may be thermal casing pressure, SCP or a combination of the above. Annuli with pressure greater than 100 psig should be evaluated promptly. The operator should determine if the pressure is thermal casing pressure by using one of the testing techniques described in 5.5.3.

5.4.1 Pressure Bleed-down/Build-up Tests

If the observed casing pressure is believed to be SCP, a pressure bleed-down test followed by a build-up test may be necessary. This test is done to determine if the pressure can be bled down completely (bled to zero psig) and to determine if the pressure builds back up and the rate at which it builds. The operator should establish a procedure for conducting the bleed-down/build-up test appropriate for the well, considering well characteristics, hardware availability, previous bleed-down tests, and suspected source of pressure. In developing the procedure, the operator should consider the following:

- Annular casing pressure evaluation tests should be performed on any annulus with 100 psig or greater pressure.
- All bleed-down/build-up tests should be documented in accordance with Section 9.
- A properly scaled pressure gauge or pressure recording device should be used.
- The adjacent casing annuli in a well should be monitored during a bleed-down/build-up test on an annulus to determine if casing-to-tubing or casing-to-casing communication exists.
- The flowing tubing pressure (FTP) and shut-in tubing pressure (SITP) should be monitored and documented during the test. Should either the FTP or SITP not be observed during the test, then the most recent observed pressure should suffice.
- Any applied pressures should be monitored and documented during the test, as well as the reason/purpose for the applied pressure.
- The subsurface safety valve should be open during the test.
- All pressures should either be continuously recorded or recorded at a set time interval, such as a minimum of every hour.
- Bleed-down should be conducted in a safe manner through an appropriately sized valve (a 1/2-in. needle valve is typically used).

- If fluids are recovered during the bleed-down, the type and volume should be documented. If a sample of the liquids is obtained, the contents can be analyzed, which may help in determining the potential or suspected source of the annular pressure.
- Careful consideration should be given to minimizing the amount of fluid allowed to be bled from an annulus. High density liquid volumes bled on the outer casing annuli should be kept to a minimum, since fluid removal may allow higher density annular fluids to be replaced by lower density produced fluids, thereby reducing annular hydrostatic pressure. This may lead to increased pressure at the surface.
- Establish when to stop the bleed-down part of the test, such as when the pressure reaches zero psig, a maximum amount of liquid fluids is recovered, and/or a set period of time (maximum of 24 cumulative hours is typically used) is reached.
- Immediately following the bleed-down test, the rate of buildup should be monitored and documented for a continuous period of time (typically a maximum of 24 hours) and/or until the pressure has stabilized.
- The operator may consider replacing any gas or liquids bled off during the test, typically with high density brine or other appropriate fluid. Items to consider in evaluating replacement of the fluids bled off include the need for corrosion inhibitors and/or oxygen scavengers, filtration, casing/tubing collapse and burst properties, differential across the packer, casing shoe fracture pressure and thermal expansion of the re-injected fluids.

5.4.1.1 Annular Casing Pressure Evaluation Tests for Wells on Active Gas Lift

There is no specific bleed-down/build-up test for evaluating the “A” annulus on a gas lift well with active gas lift (if the gas lift is not active, then the well can be analyzed as if it has no gas lift). Because of the nature of gas lift, a large gas volume exists in the “A” annulus. The bleed-off of this large gas volume is not practical and the buildup following the bleed-down will not be very informative. For example, if the annular volume occupied by gas in the production casing is 100 barrels and is bled off to zero psig, and subsequently 75 barrels of liquid were to feed into the annulus in 24 hours, the production annulus pressure would only increase by 30 psig. SCP bleed-down/build-up evaluation tests are generally not performed on the “A” annulus when gas lift is in use. Failure of a well to maintain gas lift design pressure should be investigated to determine if tubing-to-production casing communication exists.

5.4.2 Analysis of the Bleed-down/Build-Up Test

5.4.2.1 Pressure Bleeds to Zero psig with No Buildup

If the pressure bleeds to zero psig and doesn’t build back up within 24 consecutive hours, then the annulus in question does not have SCP. The pressure source was either thermal in origin or resulted from a leak of very low rate. The barriers for pressure containment are considered effective.

5.4.2.2 Pressure Bleeds to Zero psig with Buildup

If the pressure bleeds to zero psig through a 1/2-in. needle valve at a low differential pressure and builds back up to original pressure within 24 consecutive hours, then the annulus in question has a small leak. The leak rate is considered acceptable and the barriers for pressure containment are considered adequate. This well will need to be monitored for changing conditions. An increase in the annulus pressure is not necessarily an indication of an increase in leak rate. This annulus will need to be re-evaluated periodically to determine if the pressure containment barriers are still acceptable.

If the pressure bleeds to zero psig and builds back up to a lower pressure within 24 consecutive hours, then the annulus in question has a small leak. This assumes that the well is able to bleed to zero psig through a 1/2-in. needle valve at a low differential pressure. The leak rate is considered acceptable and the barriers to pressure containment are considered adequate. The annulus will need to be evaluated periodically to determine if the pressure containment barriers are still acceptable. The reasons for the pressure not building to its original value within 24 consecutive hours may include the following:

- The leak rate is very small.
- There is a large gas cap at the top of the annulus.
- A portion of the original pressure was caused by thermal effects.
- The initial pressure build-up after the bleed-down has a full column of fluid, and higher pressure will develop later as small gas bubbles slowly migrate to the top of the annulus.

5.4.2.3 Pressure Does Not Bleed to Zero psig

If the pressure does not bleed to zero psig within 24 cumulative hours through a 1/2-in. needle valve, then the barrier to pressure containment may have partially failed and, in some cases, the leak rate may be unacceptable. This condition may indicate that the leak rate is greater than what may pass through the orifice of the 1/2-in. needle valve at a low differential pressure. If this condition is on the “A” annulus, further investigation is needed to determine the leak path and leak source. Repair plans may also need to be developed. If this condition exists on the outer annuli, it is recognized that options for correction are very limited. The magnitude of the consequences and the probability of complete barrier failure will need to be considered to determine if repairs or other future actions are needed. Wells with annular pressure that do not bleed to zero psig should be evaluated further on a case-by-case basis.

5.4.2.4 Pressure Response in Adjacent Annuli

If a pressure response in an adjacent annulus during a bleed-down or build-up test occurs, communication may exist between casing annuli. There may be an additional leak allowing pressure from a source into one of the two annuli. In the case where the production string is in communication with the “A” annulus, the leak rate as evaluated by the pressure bleed-down/build-up test will determine the course of action. If the “A” annulus is able to bleed to zero psig through a 1/2-in. needle valve, then the barriers to flow are considered acceptable. The well will need to be evaluated periodically to determine if the pressure containment barriers are still acceptable.

In the case of the “A” annulus in communication with the “B” annulus, the production casing should no longer be considered an effective barrier for the formation pressure. This is considered a serious and potentially dangerous situation. The potential exists for pressure from the formation to reach the “B” annulus, which may not be designed to contain this pressure. Wells with communication between the “A” and “B” annuli should be evaluated further on a case-by-case basis.

Communication between the outer annuli will need to be evaluated on the basis of the potential consequences and probability of pressure containment failure.

5.4.3 Thermal Casing Pressure Evaluation Methods

If the observed pressure is believed to be thermal casing pressure, the operator should establish a testing protocol for demonstrating that the pressure is thermally induced and is not SCP. Typical testing protocols for determining that the observed pressure is thermal in nature are as follows:

- Shut in the well and monitor the annulus and document that the pressure falls to zero psig or near zero psig without bleeding the pressure off.
- While producing at a constant rate, bleed off 15 – 20 percent of the annular pressure, monitor the annulus and document that the annular pressure remains stable for 24 consecutive hours. If annular pressure increases, then SCP diagnostic testing is warranted.
- Change the production rate and monitor the annulus and document that the annular pressure change is directly related to the production rate change; or
- While producing at a constant rate, increase the annular pressure by 10 – 15 percent and monitor the annulus and document that the annular pressure remains stable for 24 consecutive hours. If annular pressure decreases, then SCP diagnostic testing is warranted.
- Observe the annular pressure on the “A” annulus and compare to the flowing or shut-in tubing pressure. If annular pressure is significantly different from both of these pressures, then communication is unlikely.

Alternatively, the operator may use predictive models alone or combined with a limited shut-in time or with limited bleed-down or other techniques to demonstrate that the pressure is thermally induced and not sustained. Except for bleeding the pressure to zero psig or near zero psig, the other diagnostic test methods may not determine if an annulus has SCP masked by a thermal pressure component. In all cases, the method of determining that the pressure on an annulus is thermal casing pressure is to be documented in accordance with Section 9.

For high temperature/high pressure wells, small increases in production rate can result in large increases in annular pressure. Bleeding the annular fluid will allow room for expansion as fluids heat up; however, as the wellbore cools down during a shut-in period, the wellbore fluids will contract and the casing annulus may go on a vacuum, which could allow oxygen to enter the annulus, creating a corrosion problem. This should be considered in determining the amount of fluid to bleed from the annulus.

5.4.4 Analysis of the Thermal Casing Pressure Test

5.4.4.1 Well is Shut In

If the annular pressure falls to zero psig (or near to zero psig) when the well is shut in, thermal casing pressure is indicated, and not SCP.

If the annular pressure falls to zero psig (or near zero psig) when the well is shut in, but returns to a pressure that is higher than the pressure that existed during the previous production period when the well is returned to production at the previous production rate, this is an indication that there is a small leak feeding fluid into the annulus as the well cools down. The leak rate is probably small and all pressure containment barriers are still considered acceptable.

If the pressure on the annulus stabilizes at a pressure greater than zero psig when the well is shut in, this is an indication that either communication exists between a pressure source and the annulus or that there is operator-imposed casing pressure on the annulus. In this circumstance, additional diagnostic testing is warranted.

5.4.4.2 Changing Production Rate

If the well has been produced at a constant rate with a stabilized annular pressure, the operator can increase or decrease the production rate. Following the change in production rate, if the annular pressure changes and becomes stable at the new level, this is an indication of thermal casing pressure, not SCP. The assumption is that, if a leak exists and the pressure in the annulus is in equilibrium with the pressure source, it will try to return to its equilibrium after a production rate change if the pressure observed prior to the rate change is caused by a leak.

If the well has been produced at a constant rate with a stabilized annular pressure, the operator can increase or decrease the production rate. Following the change in production rate, if the annular pressure changes (increases or decreases), but slowly moves in the direction of the annular pressure prior to the rate change, but does not reach this pressure within 24 consecutive hours, this indicates that there is communication between the annulus and a pressure source and that the leak size is possibly small. Additional investigation to determine the leak path may be needed.

If the well has been produced at a constant rate with a stabilized annular pressure, the operator can increase or decrease the production rate. Following the change in production rate, if the annular pressure changes (increases or decreases), but quickly returns to the annular pressure prior to the rate change, this is an indication of communication between the annulus and a pressure source, and that the leak size is possibly large. Additional investigation to determine the leak path and to determine if this condition is an acceptable risk may be needed.

If the well has been produced at a constant rate with a stabilized annulus pressure, the operator can increase or decrease the production rate. Following the change in production, if the “A” annulus pressure changes in the same direction as the flowing tubing pressure, this is an indication that there is communication between the production string and the “A” annulus. For example, if the production rate is reduced, the flowing temperature will decrease and the flowing tubing pressure will increase. If the “A” annulus pressure increases, then communication exists between the tubing and the “A” annulus. This type of response would indicate a leak rate that may be unacceptable and would warrant further evaluation.

5.4.4.3 Changing the Annular Pressure

If the well has been produced at a constant rate, the operator can bleed off 15 – 20 percent of the annular pressure. Following the change in annular pressure, if the pressure stays stable at the new lower level for 24 consecutive hours, this indicates that the pressure is thermal and not due to a leak. If a leak exists, the pressure in the annulus is in equilibrium with the pressure source. If the annular pressure is decreased while the well is producing at a constant rate and if a leak path is present, then the annular pressure will increase to its equilibrium pressure.

If the well has been produced at a constant rate, the operator can bleed off 15 – 20 percent of the annular pressure. Following the change in annular pressure, if the pressure increases during the following 24 consecutive hours, but to a lower pressure than the original pressure, this indicates that there is communication between the annulus and the pressure source and that the leak size is possibly small. Additional investigation to determine the communication path may be needed.

If the well has been produced at a constant rate, the operator can bleed off 15 – 20 percent of the annular pressure. Following the change in annular pressure, if the pressure increases back to the original pressure within 24 consecutive hours, this indicates that

there is communication between this annulus and a pressure source and the leak size is possibly large. Additional investigation may be needed to determine the leak path and to determine if this is an acceptable risk.

If the well has been produced at a constant rate, the operator can increase the annular pressure by 10 – 15 percent. Following the change in annular pressure, if the pressure remains stable at the new rate for 24 consecutive hours, this indicates that the pressure is thermal and not due to a leak. If the annular pressure is increased while the well is producing at a constant rate and if a leak path is present, then the annular pressure will decrease to its equilibrium pressure if the pressure in the annulus is in equilibrium with the pressure source.

If the well has been produced at a constant rate, the operator can increase the annular pressure by 10 – 15 percent. Following the change if annular pressure, if the pressure decreases during the following 24 consecutive hours, but does not return to its original pressure, this indicates communication between the annulus and a pressure source with a small leak size. Additional investigation to determine the leak path may be necessary.

5.4.5 Diagnostic Actions following Bleed-down and Build-up Tests

5.4.5.1 Analysis of Recovered Fluids

Any fluids recovered during the bleed-down test may be analyzed for their content. If the fluid from the “A” annulus is similar to the production fluids, a tubing leak may be indicated. If the fluid from the “A” annulus is different from the production fluid and is also different from the original fluids left in the annulus, a casing leak or fluid migration from a different source may be indicated. Any gases recovered may also be analyzed for the presence of hydrocarbons, CO₂ and H₂S, if applicable. Correlation of the recovered fluid’s chemical analysis with relevant drilling records, such as logs or chemical analysis of hydrocarbons in mud samples, may help identify the source of the recovered fluid.

Analysis of oil or gas from one of the outer casing annuli may help determine the source of the fluid. If the analysis of the recovered fluids indicates that the source is the producing interval, further analysis of the situation will be needed to determine the level of risk.

5.4.5.2 Location of a Tubing Leak

If a tubing leak is suspected, the SCSSV can be closed, the tubing pressure bled off above the SCSSV and the pressure in the “A” annulus monitored. If the “A” annulus pressure declines, this indicates that the leak is above the SCSSV. The location of a tubing leak below the SCSSV may be determined by setting wire line plugs at various depths and pressure testing the tubing. Note that early annular pressure response may be dominated by thermal effects and sufficient time will have to be allowed to get beyond the thermal effects.

5.4.5.3 Gas Lift Mandrels

If there are gas lift mandrels in the well, the dummy valves or live valves can be checked for leaks. It is often difficult to determine if communication exists between the production tubing and the “A” annulus or if an “A” annulus casing leak exists on a well being gas lifted. Any unexpected change in gas lift pressure or gas lift well performance should be investigated to determine if communication is the source of the problem.

5.4.5.4 Wellhead Integrity

The wellhead seal integrity may be checked by a representative of the wellhead manufacturer.

5.4.5.5 Production, Noise and Temperature Logs

Various cased hole well logs, including production logs, noise, temperature, spinner, etc., can be used to assist in determining the source or location of the leak.

5.4.5.6 No-Flow Test

The No-Flow Test (NFT) is intended to establish whether a well is capable of flowing to the surface unassisted. If a well is incapable of flowing to the surface unassisted, then this method helps establish that, even though communication between the “A” annulus and the production string may exist, the risk may be low.

5.4.5.7 Mechanical Integrity Test

The Mechanical Integrity Test (MIT) is a pressure test of an annulus. MITs are conducted for a variety of reasons, including pre-rig testing, leak evaluation, underground injection control (UIC) testing, etc. MITs can be conducted on any isolatable string of tubing, casing, or combination of strings.

5.4.6 Subsequent Bleed-down and Build-up Tests

Additional bleed-down and build-up tests should be performed at a frequency consistent with the operator's annular pressure management plan. The initial condition that resulted in annular pressure is not a static condition. Because of erosion, corrosion, subsidence, thermal cycling, etc., the communication with a pressure source may increase or worsen with time. The annular casing pressure should be re-evaluated periodically to determine if the leakage rate is still within acceptable limits. All subsequent bleed-down/build-up tests should be conducted only after carefully considering all of the potential consequences to the well. Each time an annulus with SCP is bled, original annulus fluid is being removed and replaced with a different fluid, possibly production fluids. This process may increase the pressures seen in the annulus and may rapidly escalate the seriousness of the problem. The annular cement sealing integrity may be damaged by pressure cycling if an excessive number of pressure bleed-down/build-up tests are conducted. These tests may cause tensile stress cracking in the cement. These stress induced cracks may substantially increase the flow rate and volume of formation fluids feeding SCP in the annulus. Safe pressure cycling conditions for the specific type and design of the cement in the annulus should be considered.

All bleed-down tests should be carefully planned and be meant to increase the operator's understanding of the situation.

Subsequent annular pressure evaluation tests should be conducted:

- Periodically, in accordance with the operator's annular casing management program. Subsequent tests should be conducted on wells that have SCP, thermal casing pressure and/or operator-imposed casing pressure.
- After the well is worked over, side-tracked or acid stimulated.
- In the event that there is significant annular pressure change between routine testing intervals. or
- In accordance with regulatory requirements.

6 Subsea Wells

6.1 SYSTEM OVERVIEW

6.1.1 Typical Subsea Well Schematic

As defined in 1.3, a subsea well is drilled from a floating drilling vessel that uses a subsea BOP for well control during the drilling process. The subsea wellhead system consists of a low pressure wellhead housing that connects to a structural casing string and a high pressure housing where subsequent casing strings are installed, landed, and sealed inside the housing immediately below the BOP. The well at this point can be completed in one of two methods: as a subsea well or as a hybrid well.

For subsea completions, the only annulus available for monitoring casing pressure is typically the "A" annulus (given current wellhead and tree technology). The remaining casing strings are terminated and sealed inside the subsea wellhead and cannot be monitored. Typical wellbore schematics are shown in Appendix C.

6.1.2 Key Component Overview

The subsea wellhead and christmas tree used for a subsea well are designed in accordance with API Specification 17D. Either elastomer or metal-to-metal seals, or both, may be used in the wellhead and tree.

The subsea wellhead consists of several major components:

- A low pressure wellhead housing connected to and installed with the structural (conductor) casing string. This housing provides some low pressure containment capability, but is primarily used for supplying structural support for the rest of the subsea well.
- A high pressure wellhead housing, which is a thick-walled pressure vessel, typically connected to and installed with 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 housings to

gain structural support from the structural casing. The high pressure housing has the mechanical and pressure capacity to withstand the highest expected wellbore pressure during well drilling, completion and production operations. In some cases, the high pressure housing has the capacity to withstand the highest wellbore pressure during drilling operations and a higher pressure spool is installed and production casing tied back to it to handle completion pressures.

- Subsea casing hangers individually suspend intermediate and production casing strings in a stacked arrangement inside the high pressure wellhead housing.
- Casing hanger packoffs secure and seal the casing at the casing hanger to the high pressure wellhead housing. The packoff effectively provides a pressure barrier to isolate previously installed casing from drilling operations.

The upper end of the subsea well is terminated with:

- A subsea tubing hanger suspending the weight of the production string, sealing off the “A” annulus, providing direct vertical access into the production string and separate pressure access into the “A” annulus. It also provides individual connection points for chemical, hydraulic, and electrical conduits to subsurface equipment. Access to the “A” annulus varies depending on the subsea tree and/or tubing head design.
- A subsea christmas tree of either a vertical or horizontal design.

Wellhead packoffs are installed after every internal casing string is landed inside the wellhead’s high pressure housing. 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 subsea wellhead by using an external connector that provides pressure-containing conduits that mate with the subsea tubing hanger: one for direct vertical access to the production string, the second for access to the “A” annulus. Depending on the tubing size, production casing size, and type of tree configuration (horizontal or vertical), direct vertical access into the “A” annulus may not be possible. However, pressure and fluid circulation access is typically provided by cross-over valves and loops so that communication between the production and annulus bores can be provided when needed. The cross-over valve and loop can be used to vent annulus pressure, if needed. Electronic pressure transducers may be located downstream of the annulus master valve for monitoring pressure in the “A” annulus.

6.1.3 Potential Leak Paths in the “A” Annulus

The potential leak paths into the “A” annulus include the following:

- A cement seal integrity failure in the “B” annulus combined with a casing leak in the production casing.
- Production packer leak.
- Un-cemented section in the “B” annulus combined with a casing leak in the production casing.
- Production string connection leak.
- Hole in production tubing or parting of production tubing.
- Leaks in mandrels and control lines.
- Production liner top pressure integrity failure.
- Production casing collapse.
- Production casing seal integrity leaking “B” annulus into “A” annulus.
- Tubing hanger leak.
- Seal, penetrations and connection leaks.
- Leaking subsea tree valves.

6.2 DESIGN CONSIDERATIONS

6.2.1 Casing Strings

When first brought on production, all new wells with liquid-packed annuli will normally exhibit a pressure increase caused by heating and subsequent thermal expansion of the fluids. This annular pressure build-up is referred to as thermal casing pressure.

Since all of the casing strings with the exception of the production casing string will be sealed in the subsea wellhead, design of the casing should consider the possibility of trapped annuli and the thermal effects associated with producing the well. When practical, the casing strings should be designed to withstand all potential thermal pressure or incorporate a thermal pressure mitigation system. Typical mitigation systems include the following: an open casing shoe (un-cemented) below the affected annulus, nitrogen blankets, syntactic foam material applied to the outside of the affected casing string, pressure rupture disks, or a relief valve. Annular pressure mitigation should be analyzed during the well design phase.

All or part of the thermal pressure in the “A” annulus is typically not bled off a subsea well. Bleeding should be minimized so that, when the well cools down, the annular pressure will not fall to a level significantly less than the external hydrostatic pressure. The potential for casing collapse, tubing collapse or casing burst should be carefully evaluated. If pressure is left on the casing, it should be monitored for changes and evaluated to ensure it is not masking SCP.

6.2.2 Production String

The production string is the primary conduit for produced (or injected) fluids and it should be designed to withstand the maximum anticipated pressures, temperatures and composition of fluids that it is expected to handle. The production string is normally considered to be the primary well barrier preventing uncontrolled flow from the producing formation. In many wells, the production string consists primarily of the production tubing. In other wells, the production string is more elaborate with multiple potential leak paths such as control lines and mandrels. The production string is often the source of SCP in the “A” annulus because of connection leaks, erosion and corrosion of the connection or pipe body, or pipe body failure, such as collapse.

6.2.3 Umbilical Line

The subsea well is usually controlled by a control umbilical line. The control system may use direct hydraulics, piloted hydraulics or electro-hydraulic systems. Numerous actuated valves, components and functions will typically be controlled via the umbilical line.

The tubes within the umbilical line may be either stainless steel, duplex or have a thermoplastic core. The tubes used to monitor the annulus pressure are typically very small, ranging in size from approximately $\frac{3}{8}$ in. to 1 in. If the annulus monitoring line contains a thermoplastic core, as internal pressure increases, these types of lines will expand radially (similar to a ballooning effect) until they are constrained by the confines of the umbilical line. So, low annular pressure conditions may go undetected until the change in pressure exceeds the ballooning pressure.

The annulus monitoring line may be used to monitor the pressure in the “A” annulus. The annulus monitoring line may also be used to bleed off pressure, if required. Bleeding off pressure through this line should only be done when absolutely necessary because of the potential for plugging of the line with emulsions, paraffin or hydrates. It is much better to bleed annulus pressure through the cross-over valve into the flowline if a cross-over valve is provided, and not risk damage to the umbilical.

6.3 METHODS AND FREQUENCY OF MONITORING ANNULAR CASING PRESSURE

The following sections apply to producing wells, injection wells, shut-in wells and temporarily abandoned wells. They do not apply to newly drilled and/or completed wells that have been suspended pending the installation of production facilities, pipelines, etc.

Since all of the casing strings except for the production casing are sealed in the subsea wellhead, only the “A” annulus is available for monitoring. This annulus should have the capability to be monitored continuously. Common methods of monitoring the pressure include the use of pressure transducers located downstream of the annulus master valve and/or providing an annulus monitoring line in the umbilical. Surface gauge readings may need to be corrected to account for the hydrostatic head. The “A” annulus pressure should always be stated in terms of the gauge pressure measured at the wellhead. Consideration should be given to providing a redundant method of monitoring, either continuously or intermittently, in case the primary method fails.

Although the pressure is monitored continuously, at a minimum, one pressure point should be recorded and documented daily for the “A” annulus.

All monitoring should be documented in accordance with Section 9.

6.4 DETECTION OF PRESSURE

The pressure on the “A” annulus is evaluated relative to the hydrostatic pressure at the wellhead. The potential for casing collapse should be evaluated whenever the “A” annulus pressure is less than the external hydrostatic pressure at the wellhead. Even though the negative differential pressure may be small while the well is producing, it may become significant when the well is shut in and cools down. When the “A” annulus pressure is greater than the external hydrostatic pressure, then the “A” annulus is considered to have positive annular pressure. When the positive annular pressure differential exceeds 100 psig under stabilized production conditions, then this pressure should be evaluated to determine the source of the pressure promptly.

6.4.1 New Wells—Thermal Casing Pressure

All new wells will exhibit thermal casing pressure, which may be bled down as the well is initially brought on production. However, in many cases for subsea wells, all of the thermal casing pressure in the “A” annulus is not bled off. Bleeding should be minimized so that, when the well cools down, the annular pressure will not fall to a level significantly less than the hydrostatic pressure. Bleeding should be done through the subsea tree’s cross-over circuit and not through umbilical lines accessing the annulus, if at all possible. Because of the annulus monitoring line’s small internal diameter, it is important to minimize the ingress of hydrocarbons, or other agents, which could plug the line. The pressure remaining in the annulus should be monitored in accordance with Section 6.3 for changes and to ensure that it is not masking SCP.

Annular pressure readings are consistent with thermal expansion of annular fluids if the annular pressure stabilizes once the well production rate and temperature are stabilized. Upon well startup, annular pressure increases until the well is fully heated up, and then stabilizes. Upon the well being shut in, the annular pressure decreases until the well has cooled to the geothermal temperature gradient, and then it stabilizes. The level at which the annular pressure stabilizes during heat-up and cool-down depends on the initial hydrostatic pressure trapped on the annulus and the cumulative amount of fluid bled (or pumped into) the annulus.

When the well is shut in and the well cools, annular pressure will drop. During shut-in, annular fluid may be replaced via the annulus monitor line to maintain pressure balance, if necessary.

6.4.2 Operator-Imposed Pressures

In some cases, the operator may deliberately apply pressure to the “A” annulus for gas lift, to assist in monitoring the “A” annulus for integrity or to prevent production casing collapse. Operator-imposed pressures should be monitored for changes that may indicate a need for diagnostic testing and to ensure that it is not masking SCP.

6.4.3 Potential Sustained Casing Pressure (SCP)

The annular pressure will stabilize once the well production rate and temperature are stabilized. If a change in pressure is detected during stable production operations or if the pressure increases after the well is shut-in, there is the potential for SCP. After a change of pressure has been verified, records and well history should be gathered and reviewed to assist in determining the potential cause or source of the pressure.

- Review previous monitoring records for any changes in pressure.
- Review well history for changes in production rate (oil, gas or water) or changes in flowing tubing pressure, flowing tubing temperature or changes in choke settings, and note any changes that have occurred since the last documented monitoring record.

In addition, the MAWOP as discussed in Section 4 for each annulus should be calculated if it has not been previously established.

6.5 ANNULAR CASING PRESSURE EVALUATION TESTS

6.5.1 Methods

For new wells, the observed annular pressure may be thermal casing pressure, SCP or a combination of the above. A well with an “A” annulus pressure that is 100 psig greater than the external hydrostatic pressure should be evaluated. The operator should determine if the pressure is thermal casing pressure or SCP by using one of the testing techniques described in Section 6.5.2.

Development of benchmarking operating parameters and operating characteristics during factory acceptance testing and the initial commissioning of the subsea well and control system is highly recommended.

To run a pressure bleed-down/build-up test, the fluid will have to be bled off either through the annulus monitoring line (not recommended) or through the cross-over system into the flowline. The bleed down of the “A” annulus pressure to equal the external hydrostatic pressure at the wellhead should only be done after careful consideration of all potential consequences. As the well cools down, the pressure in the “A” annulus can decrease to a pressure significantly lower than the external hydrostatic pressure at the wellhead. For high temperature and high pressure wells, small increases in production rate can result in large increases in annular pressure. Bleeding off the fluid will allow room for expansion as fluids heat up; however, as the wellbore cools down during a shut-in period, the wellbore fluids will contract and the “A” annulus may go on a vacuum, which could result in collapsed production casing and may lead to the failure of the seal assembly between the subsea tree and the wellhead. This should be carefully considered in determining the amount of fluid to bleed off.

The small volume associated with an annulus monitor line improves the accuracy for detecting small leaks and for pressure build-ups. However, the small internal diameter may be prone to plugging because of the quality of the wellbore fluids. Annulus monitor lines with a thermoplastic core are subject to radial expansion.

It is normally preferable to use the cross-over system, if provided, and the flowline between the tree and the host facility for bleed-down tests. This approach requires a comprehensive analysis of the results of the test that accounts for:

- the fluid types and densities in the flowline,
- bathymetry and routing of the flowline,
- water depth at the tree and host facility height above the seawater,
- lateral offset distance between the tree and the host facility, and
- the size/rate of the pressure build-up relative to the volume of the flowline.

During the monitoring for pressure build-up through the flowline, a small leak may be undetectable unless the well is shut in long enough for sufficient fluid volume to build up in the flowline so that it can be read at the host facility. Therefore, it is preferable to monitor the “A” annulus pressure using the pressure transducer downstream of the annulus master valve or through the annulus monitoring umbilical line with the annulus cross-over valve closed.

6.5.2 Annular Casing Pressure Test Protocols

The operator should establish a testing protocol for demonstrating that the pressure is thermally induced or is SCP. The bleed-down of the “A” annulus to a pressure equal to the external hydrostatic pressure at the wellhead or less should only be done after careful consideration of all of the potential consequences. The pressure in the production casing can go to a pressure significantly below the external hydrostatic pressure at the wellhead when the well cools down. The potential for production casing collapse should always be considered prior to bleeding off the pressure in the “A” annulus.

Typical testing protocols for determining that the observed pressure is thermal or SCP in nature are as follows:

- Observe the flowing tubing pressure and the “A” annulus pressure while producing at a constant rate. After the well has been producing at a stabilized rate, if the flowing tubing pressure and the “A” annulus pressure are significantly different, then tubing and annulus communication does not likely exist. If the flowing tubing pressure and “A” annulus pressure are close to equal, then communication may exist and another method should be used to evaluate for possible communication.
- Shut in the well, monitor the “A” annulus, and document that the pressure falls to a reasonable level within a reasonable timeframe. If the pressure rises instead of declining when the well is shut-in, then communication exists between the production string and the “A” annulus and the leak rate is probably high. If the pressure initially begins to decline when the well is shut-in but later begins to increase, then communication exists between the tubing string and the “A” annulus. If no communication was detected during the shut-in phase of the test, return the well to production at the pre shut-in production rate. The well should return to its pre-shut-in casing pressure. An increase in the casing pressure above the pre-shut-in casing pressure at the same production rate may indicate SCP because of tubing-to-annulus communication and the leak rate is possibly low.
- While producing at a constant rate, bleed 15 – 20 percent off the annular pressure and monitor the “A” annulus. This may be done by shutting in the well, bleeding the annulus fluids into the flowline, then returning the well to production at the pre shut-in production rate. Bleed-downs into the umbilical line should be carefully conducted (or avoided if at all possible) because of potential plugging with emulsions, paraffin or hydrates. If the annular pressure remains stable for 24 consecutive hours, this indicates thermal casing pressure. If the pressure doesn’t stabilize, it may be SCP. When the well is initially

returned to production after the bleed off of “A” annulus fluids, the pressure will initially rise because of thermal effects before it becomes stable at the new lower pressure.

- Change the production rate and monitor the “A” annulus for pressure changes. If the production rate is increased, then the annular pressure should increase. Likewise, if the production rate is decreased, then the annular pressure should decrease. The annular pressure should change and remain constant. If the annular pressure does not change as expected or does not remain constant after the change, then there may be SCP because of tubing-to-annulus communication. If the pressure changes as expected and remains constant, the pressure is thermal casing pressure. A decrease in production rate should result in a decrease in the “A” annulus pressure and an increase in the flowing tubing pressure. If the “A” annulus pressure increases instead of decreasing, then there is significant communication between the production tubing and the “A” annulus. If the “A” annulus first begins to decrease but later begins to rise, then communication exists between the production string and the “A” annulus, but the leak rate is possibly small.

An increase in the production rate should result in an increase in pressure in the “A” annulus and a decrease in the flowing tubing pressure. If the pressure in the “A” annulus decreases instead of increasing, then there is significant communication between the production string and the “A” annulus. If the “A” annulus pressure first begins to increase but later begins to decline, then communication exists between the production string and the “A” annulus, but the leak rate is possibly small.

- While producing at a constant production rate, increase the annular pressure by 10 – 15 percent by injecting fluid through the umbilical line and monitor the “A” annulus. If the annular pressure decreases, then SCP caused by tubing-to-annulus communication may exist. If the annular pressure remains stable for 24 consecutive hours while maintaining a constant production rate, the pressure is most likely thermal. Injection of fluid through the umbilical is possible since fluid quality and hydrate formation can be controlled during the injection of fluids.

Alternatively, the operator may use predictive models alone or in combination with a limited shut-in time bleed-down test or other techniques to demonstrate that the pressure is thermally induced and not sustained. Except for bleeding the pressure, the other diagnostic test methods may not determine if an annulus has sustained pressure masked by a thermal component. In all cases, the pressure analysis method is to be documented in accordance with Section 9.

The following general principles apply to the various diagnostic tests:

- All annular pressure evaluation tests should be documented in accordance with Section 9.
- The flowing tubing pressure (FTP) and shut-in tubing pressure (SITP) should be monitored and documented during the test. Should either the FTP or SITP not be observed during the test, then the most recently observed pressure should suffice.
- The production rate should be monitored and documented during the test.
- Any applied pressures should be monitored and documented during the test.
- The subsurface safety valve should be open during the test.
- Pressure should either be continuously recorded or recorded at a set time interval such as a minimum of every hour.
- Careful consideration should be given to the amount of fluid bled from an annulus.
- Consideration should also be given to flow assurance issues related to bleeding fluids through the annulus monitoring line.
- Establish when to stop the bleed-down part of the test.
- Immediately following the bleed-down test, the rate of build-up should be monitored and documented for a set period of time or until the pressure has stabilized.
- Both bleed-down and build-up pressure should be recorded.
- The operator may consider replacing any fluid bled off during the test with an appropriate fluid. Annulus fluid replacement should be considered when stabilized casing pressure levels are significantly below hydrostatic. Dedicated casing annulus umbilical lines, if they exist, could be used for this purpose. Items to consider when evaluating replacement of the fluids bled-off include hardware configuration, need for corrosion inhibitors, filtration, casing/tubing collapse and burst properties, differential across the packer, and thermal expansion of the re-injected fluids.

6.5.3 Diagnostic Actions following Bleed-down/Build-up Tests

6.5.3.1 Location of a Tubing Leak

If a tubing leak is suspected, the SCSSV can be closed and the tubing pressure bled off above the SCSSV while the annular casing pressure is monitored. If the production casing pressure decreases during or after bleeding off the tubing pressure above the SCSSV, then tubing-to-annulus communication may exist above the SCSSV. Note that thermal effects may dominate early annular pressure response, and sufficient time will need to be allowed to get beyond the thermal effects.

6.5.4 Subsequent Annular Pressure Evaluation Tests

Additional annular pressure evaluation tests should be performed in accordance with the operator's annular pressure management plan. The initial condition that resulted in annular casing pressure is not a static condition. Because of erosion, corrosion, subsidence, thermal cycling, etc., the communication with a pressure source may increase or worsen with time. The annular casing pressure should be re-evaluated periodically to determine if the leakage rate is still within acceptable limits. All subsequent annular pressure evaluation tests should be conducted only after carefully considering all of the potential consequences to the well.

All annular pressure evaluation tests should be carefully planned and should have the goal of increasing the understanding by the operator of the situation.

Subsequent annular pressure evaluation tests should be conducted:

- In accordance with the operator's annular casing pressure management plan. This includes wells that have SCP, thermal casing pressure and operator-imposed pressure.
- After the well is worked over, side-tracked or acid-stimulated.
- In the event that there is significant annular pressure change between routine testing intervals. or
- In accordance with regulatory requirements.

7 Hybrid Wells

7.1 SYSTEM OVERVIEW

7.1.1 Typical Well Schematic

As defined in 1.3, a hybrid well is characterized as having a subsea wellhead, surface casing head, spool and/or, tubing head and surface Christmas tree with either one casing string (single bore production riser) or two casing strings (dual bore production riser) run from the subsea wellhead and tied back to the surface. Since a subsea wellhead is used for hybrid wells with a single bore production riser, the only annulus available for monitoring for annular casing pressure is the "A" annulus. For the hybrid wells with a dual bore production riser, the "B" annulus is also available for monitoring. The remaining casing strings are terminated at the subsea wellhead and are not available for monitoring. Mudline isolation packers, run on the production string and set in the production casing, may or may not be used. Typically, mudline packers are installed in single bore production riser systems, but are optional in dual bore production riser systems. Wellbore schematics for some typical configurations are shown in Appendix C.

7.1.2 Key Component Overview

The subsea wellhead used for hybrid wells is a typical marine wellhead designed in accordance with API Specification 17D (see 6.1.2).

Mudline packoffs may be installed in the "A" annulus to isolate the annulus below the mudline from the production riser section.

The tie-back connector forms the structural and pressure-containing connection to the seafloor wellhead system. The single bore production riser or dual bore outer production riser is connected to the subsea wellhead by using either an internal or an external hydraulic tie-back 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 section is above the tie-back connector. Most of the production riser section is made up of specialized casing tubulars and connections. Special joints such as stress joints, keel joints, or transition joints may also be included in the production riser design.

The production riser may be supported by the hydro-pneumatic tensioners, air can buoyancy chambers, a combination of methods, or by the platform deck structure. The surface wellhead installed at the upper end of the production riser provides a hang-off point for the production riser and tubing strings and provides the structural and pressure-containing connection point for the surface production tree.

7.1.3 Potential Leak Paths into the “A” annulus

The potential leak paths into the “A” annulus include the following:

7.1.3.1 From the top of the highest production packer to the subsea wellhead (or mudline packoff if used)

- A cement seal integrity failure in the “B” annulus combined with a casing leak in the production casing .
- Uncemented section in the “B” annulus combined with a casing leak in the production casing.
- Production tubing connection leak..
- Hole in production tubing or parting of the production string.
- Production packer leak.
- Leak in components such as control lines and mandrels.

7.1.3.2 From the top of the subsea wellhead (or mudline packoff if used) to the surface wellhead (single or dual production riser)

- Connection leak in the production riser.
- Hole in production riser, allowing seawater to flow into production riser.
- Inner production riser leak into the outer production riser.
- Production string connection leak above mudline packoffs.
- Hole in production tubing or parting of production tubing (above mudline packoffs).
- Leak in components such as control lines and mandrels above mudline packoffs.
- Mudline packoff leaks.
- Area described in 7.1.3.1 leaks below the mudline (if mudline packoffs not used).

7.1.3.3 Subsea wellhead and production riser tie-back components

- Production casing seal leak.
- Tie-back connector leak.

7.1.3.4 Surface wellhead and tree

- Tubing hanger (or seal) leak.
- Control line or injection line leak.
- Gas lift string leak.

7.2 DESIGN CONSIDERATIONS

7.2.1 Casing Strings

When first brought on production, all new wells with liquid packed annuli will normally exhibit a pressure increase because of heating and the subsequent thermal expansion of the fluids. This annular pressure buildup is referred to as thermal casing pressure. Since all of the casing strings with the exception of liners or the production casing of a dual bore production riser system tied back from a liner will be sealed in the subsea wellhead, design of the casing should consider the possibility of trapped annuli and the thermal effects associated with producing the well. When practical, the casing strings should be designed to withstand all

potential thermal pressure, or incorporate thermal pressure mitigation systems. Typical mitigation systems include the following: an open casing shoe (uncemented) below the affected annulus, nitrogen blankets, syntactic foam material applied to the outside of the affected casing string, pressure rupture disks or a relief valve. Annular pressure mitigation should be analyzed during the design process.

When practical, the production casing string should be designed to withstand the calculated thermal pressures in “A” annulus, or the design should allow the thermal pressure to be bled off or incorporate a pressure buffer such as a nitrogen cap. However, if the potential exists for casing collapse, then bleeding off the thermal casing pressure should be carefully evaluated. If pressure is left on the casing, it should be monitored for changes and to ensure that it is not masking SCP.

7.2.2 Production String

The production string is the primary conduit for produced (or injected) fluids and it should be designed to withstand the maximum anticipated pressures, temperatures and composition of fluids that it is expected to handle. The production string is normally considered to be the primary well barrier preventing uncontrolled flow from the producing formation. In many wells, the production string consists primarily of the production tubing. In other wells, the production string is more elaborate, with multiple potential leak paths such as control lines and mandrels. The production string is often the source of SCP in the “A” annulus because of connection leaks, erosion and corrosion of the connection or pipe body, or pipe body failure, such as collapse.

Additional considerations for the design of the production tubing within the production riser section include the following items:

- Dynamic loading caused by the motions of the surface facility and the production riser system should be taken into account during the design phase to ensure adequate fatigue life.
- Centralization of the tubing to prevent buckling between the constraints of the surface tubing hanger and the tubing hanger/packoff deployed below the mudline, if used.
- Adequate protection of the control lines for critical functions such as the SCSSV and chemical injection lines.

7.2.3 Production Riser Design

As a part of the production riser design, consideration should be given to vortex-induced vibration (VIV) and vortex-induced motions (VIM) and the resulting metal fatigue. Hybrid wells have the additional failure mode of production riser failure caused by VIV and/or VIM. In the event that SCP is detected on the “A” or “B” production riser annulus, the production riser fatigue life should be re-evaluated to determine if loss of pressure containment is possible because of production riser failure. Should a significant environmental event occur, such as a hurricane or loop current, the production risers should be re-evaluated for production riser fatigue.

7.2.4 Quality Control

Because of the dynamic loading environment of the hybrid well systems and the criticality of the barriers, equipment reliability must be ensured in the design, manufacturing, transportation, installation and operation of hybrid well systems.

This level of reliability can be achieved by project specific analysis, inspection and training programs.

7.3 METHODS AND FREQUENCY OF MONITORING ANNULAR CASING AND PRODUCTION RISER PRESSURE

The following sections apply to producing wells, injection wells, shut-in wells and temporarily abandoned wells. They do not apply to newly drilled wells that have been temporarily plugged pending the installation of production facilities, pipelines, etc.

Since all of the casing strings except for the production string are sealed in the subsea wellhead, the only casing annulus available for monitoring is the “A” annulus, unless the casing tieback of a dual bore production riser is tied back from a liner; then the “B” annulus can be monitored from the subsea wellhead to the tieback. If the inner production riser of a dual bore production riser system is tied back from the subsea wellhead only, then the “B” annulus can only be monitored above the subsea wellhead. The “A” annulus should be equipped so that it can be monitored continuously. Methods of monitoring pressure below a mudline packoff may include monitoring via a gas lift tubing short string, electric annulus pressure gauge, or installation of a monitoring line. Consideration should be given to providing a redundant method of monitoring either continuously or intermittently in case the primary method fails.

If mudline packoffs are used, the pressure within the production riser “A” annulus should be equipped to be measured continuously above the packoffs in addition to the “A” casing annulus as described above. Unless the mudline packoffs leak, the production riser section will be isolated from the rest of the wellbore above the mudline packoffs.

For dual bore production risers, the outer production riser annulus, “B” annulus, should be equipped so that it can be monitored continuously.

In some cases, the annular fluid may be displaced with nitrogen or an insulating gel in either the production riser “A” annulus and/or in the “B” annulus for thermal management and to assist in detecting small changes in pressure. Alarms that indicate when pressure is sensed or when a change in pressure of a set magnitude occurs can also be installed.

Although the pressure is monitored continuously, at a minimum, one pressure point should be recorded and documented daily for each annulus available for monitoring.

All monitoring should be documented in accordance with Section 9.

7.4 DETECTION OF PRESSURE

7.4.1 New Wells—Thermal Casing Pressure

All new wells will exhibit thermal casing pressure, which may be bled down from the “A” and/or “B” annuli as the well is initially brought on production. Any pressure remaining in an annulus should be monitored for changes and to ensure that it is not masking SCP.

7.4.2 Operator-Imposed Pressures

In some cases, the operator may deliberately apply pressure to the “A” annulus for gas lift, minimizing differential pressure across equipment, or simply for positive monitoring pressure. In the production riser section, the operator may apply nitrogen or insulating gel in the “A” or “B” annulus. When the operator is using nitrogen for insulation, the production riser fluids are displaced by nitrogen. A positive pressure will be necessary to monitor the production riser for change. Operator-applied pressures greater than 100 psig should be monitored for change and periodically evaluated to ensure that they are not masking SCP. Diagnostic testing will be necessary to ensure that the applied pressure is not masking SCP. Wells that have nitrogen gas pressure applied for thermal casing insulation should be evaluated as described in 7.5.4.

7.4.3 Potential Sustained Casing Pressure (SCP)

When annular pressure has been initially detected in an annulus (after the initial thermal casing pressure has been bled off, or if the pressure was not completely bled off, a change in pressure), there is the potential for SCP. After the existence of annular pressure (change in pressure, decrease or increase in pressure) has been verified, records and well history should be gathered and reviewed to assist in determining the potential cause or source of the pressure.

- Review previous monitoring records for any changes in pressure.
- Review well history for changes in production rate (oil, gas or water), or changes in flowing tubing pressure, and or changes in choke sizes and note any changes that have occurred since the last documented monitoring record.

Pressure greater than 100 psi on the hybrid production riser system should be investigated very carefully to determine its source and effect on the production riser system. Serious consideration should be given to shutting in the well, depending on the pressure magnitude, the location of a leak and the pressure source. The operator’s philosophy should be included in his annular casing pressure management procedure.

In addition, the MAWOP as discussed in Section 4 for each annulus should be calculated if it has not been previously established.

7.5 ANNULAR PRESSURE EVALUATION TESTS

For new wells, the observed annular pressure may be thermal casing pressure, SCP or a combination of the above. Wells with pressure on any annulus greater than 100 psig should be evaluated promptly. The operator should determine if the pressure is thermal casing pressure by using one of the testing techniques described in 7.5.1.

7.5.1 Pressure Bleed-down/Build-up Tests

If the observed casing pressure is believed to be SCP, a pressure bleed-down test followed by a build-up test may be necessary. Since a hybrid well is a subsea well brought to the surface with production risers, pressure bleed-down and build-up testing should not be performed until careful consideration has been given to the possibility of casing or production riser collapse. This test is done to determine if the pressure can be bled completely off and to determine if the pressure will build back up and the rate at which it builds. The operator should establish a procedure for conducting the bleed-down/build-up test appropriate for the well, considering well characteristics, hardware availability, previous bleed-down tests, and suspected source of pressure. In developing the procedure, the operator should consider the following:

- Annular pressure evaluation tests should be performed on any well with 100 psig or greater pressure on any annular space.
- All bleed-down/build-up tests should be documented in accordance with Section 9.
- The flowing tubing pressure (FTP) and shut-in tubing pressure (SITP) should be monitored and documented during the test. Should either the FTP or SITP not be observed during the test, then the most recently observed pressure should suffice.
- The adjacent casing annulus (“A” or “B”) should be monitored and documented during the test.
- Any applied pressures should be monitored and documented during the test.
- The SCSSV should be open during the test.
- Pressure should either be continuously recorded or recorded at a set time interval such as a minimum of every hour.
- Bleed-down should be conducted in a safe manner through an appropriately sized valve (a 1/2-in. needle valve is typically used).
- If liquid fluids are recovered during the bleed-down, the type and total volume recovered should be documented. Careful consideration should be given to the amount of fluid allowed to be bled from an annulus. Liquid volume bled should be kept to a minimum since fluid removal reduces hydrostatic pressure, if high density fluids are removed and influx fluids are low density. This may lead to increased leakage and consequently increased pressure at the surface. If a liquid sample is recovered, the contents should be analyzed to determine the potential source.
- Establish when to stop the bleed-down part of the test, such as when the pressure reaches zero psig or other minimum pressure at the surface, a maximum amount of liquid fluid is recovered, and/or a set period of time (maximum of 24 cumulative hours is typically used) has elapsed.
- Immediately following the bleed-down test, the rate of buildup should be monitored and documented for a set period of time (typically a maximum of 24 consecutive hours) and/or until the pressure has stabilized.
- Both bleed-down and buildup should be recorded.
- The operator may consider replacing any gas or liquids bled off during the test with an appropriate fluid. Items to consider when evaluating replacement of the fluids bled include need for corrosion inhibitors and/or oxygen scavengers, filtration, casing/tubing collapse and burst properties, differential across the packer, and thermal expansion of the re-injected fluids.

7.5.2 Analysis of the Bleed-down/Build-up Test

7.5.2.1 Thermal Casing Pressure

If the pressure bleeds to zero psig and does not build back up within 24 consecutive hours, then the annulus does not have SCP. The pressure was either thermally induced or from a very low rate leak. The barriers for pressure containment are very effective.

7.5.2.2 Pressure Bleeds to Zero psig

If the pressure bleeds to zero psig through a 1/2-in. needle valve at a low differential pressure and builds back up to original pressure within 24 consecutive hours, then the annulus has a small leak. The leak rate is considered acceptable and the barriers for pressure containment are considered adequate. This annulus will need to be monitored for changing conditions. An increase in the annular pressure is not necessarily an indication of an increase in leak rate. This annulus will need to be re-evaluated periodically to determine if the pressure containment barriers are still acceptable.

If the pressure bleeds to zero psig through a 1/2-in. needle valve at a low differential pressure and builds back up to a lower pressure within 24 consecutive hours, then the annulus in question has a small leak. The leak rate is considered acceptable and the barriers to pressure containment are considered adequate. The annulus will need to be evaluated periodically to determine if the

pressure containment barriers are still acceptable. The reasons for the pressure not building to its original pressure within 24 consecutive hours may include the following:

- The leak rate is very small.
- There is a gas cap at the top of the annulus.
- A portion of the original pressure was caused by thermal effects.
- The initial pressure buildup after the bleed-down has a full column of fluid, and higher pressure will develop later as small gas bubbles slowly migrate to the top of the annulus.

7.5.2.3 Pressure Does Not Bleed to Zero psig

If the pressure doesn't bleed to zero psig within 24 cumulative hours through a 1/2-in. needle valve, then the barrier to pressure containment and leak rate may be considered unacceptable. This condition may indicate that the leak rate is greater than what may pass through the orifice of a 1/2-in. needle valve at a low differential pressure. If this is on the "A" annulus or the "A" production riser or "B" production riser, further investigation is needed to determine if a leak is present and to determine the leak source. Repair plans may also need to be developed. It is not possible to determine if the condition exists on the outer casing annuli because of the design and construction of the subsea wellhead used on hybrid wells.

7.5.2.4 Thermal Casing Pressure Evaluation Methods

If the observed pressure is believed to be thermal casing pressure, the operator should establish a testing protocol for demonstrating that the pressure is thermally induced and is not SCP. Typical testing protocols for determining that the observed pressure is thermal in nature are as follows:

- Shut in the well and monitor the annulus. Document if the pressure falls to a reasonable pressure within a reasonable period of time. Thermally induced pressure may take several days to fall completely to zero psig.
- While producing at a constant rate, bleed 15 – 20 percent of the annular pressure and monitor the annulus and document that the annular pressure remains stable for 24 consecutive hours; or
- Change the production rate and monitor the annulus and document that the annular pressure change in accordance to the production rate change. The pressure must be shown to stabilize and stay stable for a 24 consecutive hour period; or
- While producing at a constant rate, increase the annular pressure by 10 – 15 percent and monitor the annulus and document that the annular pressure remains stable for 24 consecutive hours.
- Observe the flowing tubing pressure and the "A" production riser annulus pressure while producing at a constant rate. If the flowing tubing pressure and the production riser annulus pressure are significantly different, then tubing and annulus communication likely does not exist.

Alternatively, the operator may use predictive models or predictive models combined with a limited shut-in time, bleed-down or other techniques to demonstrate that the pressure is thermally induced and not sustained. Except for bleeding the pressure increase to zero psig or near zero psig, the other diagnostic test methods may not determine if an annulus has sustained pressure masked by a thermal component. In all cases, the pressure analysis method is to be documented in accordance with Section 9.

7.5.3 Analysis of the Thermal Casing Test

7.5.3.1 Well is Shut In

If the pressure on the annulus falls to zero psig or near to zero psig when the well is shut in, this is an indication that the pressure on the annulus is thermal casing pressure and not SCP.

If the pressure on the "A" annulus increases when the well is shut-in, then significant communication exists between the production string and the "A" annulus. If the pressure on the "A" annulus first decreases and then later increases to a level higher than the pre-shut-in annulus pressure, then communications exists between the production string and the "A" annulus.

If the pressure on the annulus goes to zero psig (or near zero psig) when the well is shut in, but returns to a higher pressure when the well is returned to production at the same production rate as before the shut-in, this is an indication that there is a small fluid leak into the annulus as the well cools down. The leak rate is small and all pressure containment barriers are still considered acceptable.

If the pressure on the annulus stabilizes at a pressure greater than zero psig when the well is shut in, this is an indication that either communication exists between a pressure source and the annulus or that there is operator-applied pressure on the annulus. This condition does not give an indication of leak rate or size; it only indicates that a leak may exist.

7.5.3.2 Changing Production Rate

If the well has been produced at a constant rate with a stabilized annular pressure, the operator can increase or decrease the production rate. Following the change in production rate, if the annular pressure changes and becomes stable at the new level, this is an indication of thermal casing pressure, not SCP. The assumption is, that if a leak exists, the pressure in the annulus is in equilibrium with the pressure source; it will try to return to its equilibrium after a production rate change if the pressure is caused by a leak.

A decrease in production rate should result in a decrease in annular pressure because of thermal effects and an increase in flowing tubing pressure. If the annular pressure increases instead of decreasing, then there is significant communication between the production string and the “A” annulus.

An increase in production rate should result in an increase in annular pressure because of thermal casing effects and a decrease in the flowing tubing pressure. If the annular pressure decreases instead of increasing, then there is significant communication between the production string and the “A” annulus.

If the well has been produced at a constant rate with a stabilized annular pressure, the operator can increase or decrease the production rate. Following the change in production rate, if the annular pressure changes, but slowly moves in the direction of the annular pressure prior to the rate change, but does not reach this pressure within 24 consecutive hours, this indicates that there is communication between the annulus and a pressure source and that the leak size is possibly small. Additional investigation to determine the leak path may be needed.

If the well has been produced at a constant rate with a stabilized annular pressure, the operator can increase or decrease the production rate. Following the change in production rate, if the annular pressure changes, but quickly returns to the annular pressure prior to the rate change, this is an indication of communication between the annulus and a pressure source and that the leak size is possible large. Additional investigation to determine the leak path and to determine if it is an acceptable risk may be needed.

If the well has been produced at a constant rate with a stabilized annulus pressure, the operator can increase or decrease the production rate. Following the change in production rate, if the annulus pressure does not change, this is an indication that there may be communication between the annulus and a pressure source and that the leak size is large. This may also indicate that the leak source is independent of the producing interval. Additional investigation to determine the leak path and to determine if it is an acceptable risk may be needed.

7.5.3.3 Constant Production Rate

If the well has been produced at a constant rate, the operator can bleed off 15 – 20 percent of the annular pressure. Following the change in annular pressure, if the pressure stays stable at the new lower level for a 24 consecutive hour period, this indicates that the pressure is thermal casing pressure and not caused by a leak. If a leak exists, the pressure in the annulus is in equilibrium with the pressure source. If the annular pressure is decreased while the well is producing at a constant rate and if a leak path is present, then the annular pressure will increase to its equilibrium pressure.

If the well has been produced at a constant rate, the operator can bleed off 15 – 20 percent of the annular pressure. Following the change in annular pressure, if the pressure increases during the following 24 consecutive hour period, but to a lower pressure than the original pressure, this indicates that there is a communication between the annulus and pressure source and that the leak size is possibly small. Additional investigation to determine the leak path may be needed.

If the well has been produced at a constant rate, the operator can bleed off 15 – 20 percent of the annular pressure. Following the change in annular pressure, if the pressure increases back to the original pressure within 24 consecutive hours, this indicates that there is communication between the annulus and a pressure source and the leak size is possibly large. Additional investigation may be needed to determine the leak path and to determine if this is an acceptable risk.

If the well has been produced at a constant rate, the operator can increase the annular pressure by 10 – 15 percent. Following the change in annular pressure, if the pressure stays stable at the new increased level for a 24 consecutive hour period, this indicates that the pressure is thermal casing pressure and not due to a leak. If the annular pressure is increased while the well is producing at

a constant rate and if a leak path is present, then the annular pressure will decrease to its equilibrium pressure. This conclusion assumes that the pressure in the annulus is in equilibrium with the pressure source.

If the well has been produced at a constant rate, the operator can increase the annular pressure by 10 – 15 percent. Following the change in annular pressure, if the pressure decreases during the following 24 consecutive hour period, but does not return to its original pressure, this condition indicates communication between the annulus and a pressure source with a small leak size. Additional investigation to determine the leak path may be necessary.

While producing at a constant rate, observe the flowing tubing pressure and the “A” annulus pressure. After the well has been producing at a stabilized rate, if the flowing tubing pressure and the “A” annulus pressure are significantly different, then tubing-to-annulus communication likely does not exist. If the flowing tubing and the “A” annulus pressure are nearly equal (new or old well), then communication may exist and another method should be used to evaluate for possible communication.

7.5.4 Operator-Applied Pressure in the Production Riser Annulus

The operator may displace the production riser fluids with nitrogen or other products for thermal insulation, heat management, or for other purposes. The nitrogen or other products may be applied to the “A” or “B” annulus either above or below the mudline. Should nitrogen or other products replace the production riser fluids, it is not recommended that the production risers be bled to zero psig to evaluate for SCP. Periodically, these production risers may need to be evaluated to determine if the applied pressure is masking SCP. If well conditions require a diagnostic check, the operator may consider the following procedures.

- While producing at a constant rate, bleed 15 – 20 percent of the casing pressure, monitor the annulus, and document that the casing pressure remains stable for a 24 consecutive hour period.
- Change the production rate, monitor the annulus, and document that the casing pressure changes in accordance to the production rate change. The pressure must be shown to stabilize and stay stable for a 24 consecutive hour period; or
- While producing at a constant rate, increase the casing pressure by 10 – 15 percent and monitor the annulus, and document that the casing pressure remains stable for a 24 consecutive hour period.
- Observe the annular pressure on the “A” annulus and compare it to the flowing or shut-in tubing pressure. If the annular pressure is significantly different from both of these pressures, then communication is unlikely.

7.5.5 Production Riser Pressure Above Mudline Packoff

SCP above mudline packoffs in the “A” annulus may be an indication of a production string leak above the packoffs. The method of determining if SCP is present above the mudline packoff may vary depending on the type of fluid in the production riser annulus above the mudline packoff. The behavior of nitrogen will be different than if gel or brine-based packer fluids are used. The operator should consider the type of fluids in the production riser when determining the operational and diagnostic procedures.

7.5.6 Diagnostic Actions Following Bleed-down/Build-up Tests

7.5.6.1 Analysis of Recovered Liquids

Any fluids recovered during the bleed-down test may be analyzed for their content. If the fluid is similar to the production fluids, a tubing leak may be indicated. If the fluid is different from the production fluid and from the original fluids left in the annulus, a casing leak or fluid migration from a different formation may be indicated. Any gases recovered may also be analyzed for the presence of hydrocarbons, CO₂ and H₂S, if applicable. Correlation of the recovered fluid’s chemical analysis with relevant drilling records, such as logs or chemical analysis of hydrocarbons in mud samples, may assist with the identification of the location the recovered fluid’s source formation.

7.5.6.2 Location of Tubing Leak

If a tubing leak is suspected, the SCSSV can be closed and the tubing pressure bled off above the SCSSV and the casing pressure monitored. If the annular pressure declines, this indicates that the leak is above the SCSSV. The location of a tubing leak below the SCSSV may be determined by setting wire line plugs at various depths and pressure testing the tubing. Note that thermal effects may dominate early annular pressure response, and sufficient time will need to be allowed to get past the thermal effects.

7.5.7 Subsequent Annular Pressure Evaluation Tests

Additional annular pressure evaluation tests should be performed at a frequency consistent with the operator's annular pressure management plan. The initial condition that resulted in annular casing pressure is not a static condition. Because of erosion, corrosion, subsidence, thermal cycling, etc., the communication with a pressure source may increase or worsen with time. The annular casing pressure should be re-evaluated periodically to determine if the leakage rate is still within acceptable limits. All subsequent annular pressure evaluation tests should be conducted only after carefully considering all of the potential consequences to the well. Each time an annulus with SCP is bled, original annulus fluid is being removed and replaced with a different fluid, possibly production fluids. This process may increase the pressures seen in the annulus and may rapidly escalate the seriousness of the problem. The annular cement sealing integrity may be damaged by pressure cycling if an excessive number of pressure bleed-down/build-up tests are conducted. These tests may cause tensile stress cracking in the cement. These stress-induced cracks may substantially increase the flow rate and volume of formation fluids feeding SCP in the annulus. Safe pressure cycling conditions for the specific type and design of the cement in the annulus should be considered.

All annular pressure evaluation tests should be carefully planned and should have the goal of increasing the understanding by the operator of the situation.

Subsequent annular evaluation tests should be conducted in the following situations:

- If the annulus or production riser pressure is greater than 20 percent of the MIYP for the casing or production riser, it should be re-evaluated at a minimum once every two years. This includes annuli that have SCP, thermal casing pressure and/or operator-imposed pressure.
- After the well is worked over, side tracked or acid stimulated.
- When the "A" or "B" annulus below a mudline packer increases by 200 psig, or in accordance with the operator's annular casing pressure management program.
- When the "A" or "B" production riser pressure increases by 100 psig, or in accordance with the operator's annular casing pressure management program.
- In accordance with regulatory requirements.

8 Mudline Suspension Wells

8.1 SYSTEM OVERVIEW

8.1.1 Typical Mudline Suspension Well Schematic

As defined in 1.3, a mudline suspension well is characterized as having a surface wellhead that allows a well to be drilled by using a surface BOP. Mud-line suspension wells are typically drilled in shallow water by using a jack up drilling rig. The mudline suspension equipment is designed to support the weight of each subsequent 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. Each casing string may be disconnected at the mudline. These wells may be temporarily abandoned with only a casing stub at the seafloor, pending the installation of a platform over the well or the completion of the well as a subsea well.

The mudline suspension well may be completed at the surface or subsea. For surface completions, the well uses a surface wellhead and christmas tree with multiple casing strings run from the mudline suspension equipment and tied back to the surface. It is possible to tie back each casing string from the production to the surface casing. Normally, all the casings are not tied back to the surface. Therefore, a single casing annular space above the mudline may be in communication with multiple annuli below the mudline.

For subsea completions, the well uses a subsea tubing head and a subsea tree. One or two casing strings are run from the mudline suspension equipment and tied back to the subsea tubing head. The tubing head uses the conductor casing for added structural support. Unlike the true subsea wellhead, where all of the casing annuli are sealed in the high pressure housing except for the "A" annulus, in a mudline conversion subsea well the casing annuli that are not tied back to the tubing head are open to the seafloor and do not have pressure containment. The mudline conversion subsea well is described completely in API Specification 17D.

The number of annuli available for monitoring depends on the type of completion and number of casing strings tied back. For subsea completions, the "A" annulus is available for monitoring, and in some cases the "B" annulus is also available for monitoring. The remaining casing strings are terminated at the mudline suspension equipment and are not available for monitoring, nor

are they capable of containing pressure. For subsea wells, monitoring is typically conducted via the annulus monitoring line provided in the umbilical. The appropriate annular valve is opened and the pressure is observed on the annulus monitoring line. If required, pressure is also bled off through this line because these wells are generally not equipped with a cross-over valve from the “A” annulus to the flowline. It is not recommended that annulus pressure be bled into the annulus monitoring line unless absolutely necessary because of the risk of plugging with hydrates, oil, emulsion or debris.

For surface completions, the “A” annulus and the “B” annulus are available for monitoring. Other annuli may also be available for monitoring. For the surface tieback, it is possible to tie back all the casing annuli to a surface wellhead; therefore, it may be possible to have “C” and “D” annuli, but this is not a common configuration. The “B” or “C” annulus at the surface may be connected to two or more casing annuli at the mudline. There are no isolation seals used in the mudline suspension equipment at the mudline. Isolation seals may be in either the subsea tubing head or surface wellhead. Typical wellbore schematics are shown in Appendix C.

8.1.2 Key Component Overview

The mudline suspension equipment used for surface or subsea wells is designed in accordance with API Specification 17D.

The mudline suspension equipment consists of several components for each casing string run in the well:

- Casing load rings that suspend the casing weight below the seafloor.
- Running string connectors, which connect and seal the casing above the mudline suspension equipment (to the surface) to the top of its corresponding mudline casing hanger during drilling operations. The connection allows for easy recovery of the tie-back strings, which connect and seal the completion casing strings to the mudline casing hangers during well completion operations. The connection allows for installation of the tie-back casing string.
- Tie-back connector.
- Mudline casing hanger temporary abandonment caps, installed when the mudline well is being temporarily abandoned.

No seals are used between any of the casing hangers in the mudline suspension equipment. However, seal assemblies are used to isolate one or more casing annuli when either the temporary abandonment caps or the tie-back casing strings are installed.

The casing tie-back connector forms a structural and pressure-containing connection appropriate for the casing string’s load and pressure capacities.

Above the tie-back connector is the production riser (or conductor pipe) section. Surface production risers extend from the seafloor all the way to a specified height above the water. Subsea production risers extend only to a predetermined point above the seafloor. The upper end of the production riser is terminated with either:

- Surface wellhead and a tubing head, providing hang-off points for the production riser and production strings and providing the structural and pressure-containing attachment point for the surface christmas tree; or
- Subsea tubing head, providing hang-off points for the casing tieback and production strings and provides the structural and pressure containing attachment point for the subsea tree.

8.1.3 Potential Leak Paths

The potential leak paths into the “A” annulus include the following:

8.1.3.1 Leak sources from the top of the highest production packer to the mudline suspension tie-back connector

- A cement seal integrity failure in the “B” annulus combined with a casing leak in the production casing.
- Uncemented section in the “B” annulus combined with a casing leak in the production casing, provided that the “B” annulus is contained within a tieback. There are numerous mudline conversion subsea wells with only a single casing tieback. In this case, an uncemented pressure source in the “B” annulus would be able to flow freely to the seafloor.
- Production packer leak.
- Production tubing connection leak.
- Hole in production tubing or parting of the production tubing.
- Leak in chemical, gas lift and control lines and mandrels.
- Production packer seal leak.

- Production liner top pressure integrity failure.

8.1.3.2 Leak sources from two or more production risers (or conductor pipes) that run from the top of the mudline suspension system tie-back connectors that thread and seal into the mudline suspension system to the surface casing head(s).

- Connection leaks.
- Hole in production riser.
- Production tubing connection leak.
- Hole in production tubing or parting of the production tubing.
- Leak in surface casing head.
- Since it is possible for two or three casing annuli to be tied back within the “B” production riser, pressure from the “B” production riser annulus could leak into the “A” annulus above the mudline tie-back if communication exists. The source of this pressure could be from one or two intermediate casing annuli below the mudline or the surface casing annuli below the mudline.

8.1.3.3 Surface casing heads and tubing heads

- Production casing hanger leak.
- Tubing hanger leak.

8.1.3.4 Surface tubing hanger and Christmas tree

- Tubing hanger leak.

8.1.3.5 Subsea tubing hanger and Christmas tree

- Tubing hanger leak.

8.2 DESIGN CONSIDERATIONS

8.2.1 Casing Strings

When first brought on production, all new wells with liquid-packed annuli will normally exhibit a pressure increase because of heating and the subsequent thermal expansion of the fluids. This annular pressure build-up is referred to as thermal casing pressure. When the mudline suspension system wells are drilled, casing design is typical of any fixed platform well. While being drilled, all casing strings are tied back to the surface. When finally completed, a mudline suspension well with a surface wellhead may not have all of its casing strings tied back at the mudline. In the event of SCP, the production riser annulus that contains two or more casing tops not tied back may be exposed to more pressure than this production riser (casing) was designed for during drilling operations. Annular pressure mitigation should be analyzed during the design process.

A mudline suspension well may be tied back to a subsea tree. These wells currently exist with only single and dual casing tie-backs. The casing strings that are not tied back for the subsea well are open at the seafloor without any pressure containment. Consideration may need to be given to the placement of cement tops in these annular spaces. Annular pressure mitigation should be analyzed during the design process.

When practical, the production casing should be designed for thermal casing pressure such that the thermal casing pressure can be bled off, be designed to withstand all potential thermal casing pressure or incorporate a pressure buffer such as a nitrogen cap. If pressure is left on the casing, it should be monitored for changes and evaluated to ensure that it is not masking SCP.

8.2.2 Production String

The production string is the primary conduit for produced (or injected) fluids and it should be designed to withstand the maximum anticipated pressures, temperatures and composition of fluids that it is expected to handle. The production string is normally considered to be the primary well barrier preventing uncontrolled flow from the producing formation. In many wells, the production string consists primarily of the production tubing. In other wells, the production string is more elaborate, with multiple potential leak paths such as control lines and mandrels. The production string is often the source of SCP in the “A” annulus because of connection leaks, erosion and corrosion of the connection or pipe body, or pipe body failure, such as collapse.

8.2.3 Umbilical Line

For mudline suspension subsea wells, the well is controlled by a control umbilical line. Typically, the control system will be direct hydraulics. The tubes within the umbilical may be either stainless steel or have a thermoplastic core. The tubes used to monitor the annulus pressure are typically very small, ranging in size from approximately $\frac{3}{8}$ in. to 1 in. If the annulus monitoring line has a thermoplastic core, it should be recognized that these types of lines grow radially (similar to a ballooning effect) as internal pressure increases until they are constrained by the confines of the umbilical line. So, low pressure situations may be undetectable until the change in pressure exceeds the ballooning pressure.

The annulus monitoring line may be used to monitor the pressure within the “A” annulus (and “B” annulus, where equipped). The annulus monitoring line is also used to bleed off pressure, if required. Bleeding off pressure through this line should only be done when absolutely necessary because of potential plugging of the line with emulsions, paraffin or hydrates.

8.3 MONITORING, PRESSURE DETECTION, ANNULAR PRESSURE EVALUATION TESTING AND ANALYSIS

Mudline suspension wells converted to subsea wells should follow the monitoring, pressure detection, annular pressure evaluation testing and analysis methods outlined for subsea wells in Chapter 6.

Mudline suspension wells tied back as surface wells should follow the monitoring, pressure detection, annular pressure evaluation testing and analysis methods and procedures for fixed platform wells outlined in Chapter 5.

9 Documentation

9.1 ANNULAR PRESSURE MANAGEMENT PLAN

Each operator should establish a written plan, policy or procedure for handling annular pressure in offshore wells. Consideration should be given to including the following elements in the plan, as applicable:

- personnel responsibilities,
- monitoring frequency,
- monitoring methods,
- MAWOP calculations,
- diagnostic test methods,
- diagnostic test frequency,
- documentation methods,
- record retention period,
- regulatory agency requirements.

Other items or issues, as applicable, that operators may also want to consider including in their plan are as follows:

- Designation of a properly qualified individual to manage the delivery of well integrity and assurance throughout the complete life cycle of the well.
- Well operating procedures, including well startup and shutdown procedures, special operating circumstances.
- Well handover procedures.
- Wellhead movement parameters.
- Scale control procedures.
- Corrosion/Erosion management procedures.
- Hydrate prevention procedures.
- Well intervention procedures.
- Well service operating procedures.
- Contingency plans.
- Christmas tree/wellhead inspection, maintenance and testing program.

9.2 MONITORING RECORDS

Written records of all annular pressure monitoring should be maintained either on the platform or at the nearest field office for a period of time consistent with the operator’s corporate policy or for a minimum of two years. Written records include hand-written records, records kept on a computer database, and records from an automatic recording device. For wells that are required to

be continuously monitored, at least one point each day should be captured or recorded. For subsea wells, records should indicate if the pressure recorded is at the wellhead or at the platform and any corrections made to account for hydrostatic pressure. All monitoring records should meet the minimum requirements of the applicable regulatory agency.

At a minimum, written monitoring records should include the following information:

- date;
- facility identification;
- well name;
- annulus identification;
- annulus pressure;
- identification of person recording the information;
- well status (flowing, gas lift, shut-in, etc.);
- well schematic;

Optional additional information that may be helpful includes:

- lease name;
- lease number;
- well API number;
- previous monitored pressure;
- tubing pressure (flowing, shut-in);
- flowline or wellhead temperature;
- production rate (oil, gas, water);
- gas lift or injection (volume, pressure);
- applied pressure information (type or reason, rate, pressure);
- casing and tubing data (size, weight and grade);
- date of last bleed-down/build-up test;
- monitoring frequency;
- any additional comments.

An operator may find it helpful to develop a monitoring report form or database to be used by field personnel.

9.3 DIAGNOSTIC TEST RECORDS

Written records of all diagnostic tests should be maintained on either the platform or at the nearest field office consistent with the operator's corporate policy or for a minimum of two years. Written records should meet the minimum requirements of the applicable regulatory agency. An operator may find it helpful to develop a report form to be utilized by field personnel.

At a minimum, the following information should be documented for following diagnostic tests:

9.3.1 Bleed-down/Build-up Tests

Test procedure (may reference a standard procedure for the type of test being conducted, or if a specific procedure was developed for this particular test, it should be documented)

- date;
- identification of person conducting the test;
- facility identification;
- well name;
- well status (flowing, gas lift, shut-in, etc.);
- well type (fixed platform, subsea, hybrid, mud-line suspension);
- identification of casing being evaluated (size, weight and grade);
- type of pressure being evaluated (scp, thermal casing, operator-imposed);
- applied pressure information (type or reason, rate, pressure);
- start and end time for bleed-off;
- start and end time for buildup;
- pressure for casing being evaluated and for adjacent tubing and/or casing (including any applied pressures) prior to the bleed-down and recorded hourly during the bleed-down (maximum bleed-down time is 24 cumulative hours);

- pressure for casing being evaluated during the pressure buildup in one hour increments for 24 consecutive hours;
- confirm SCSSV was fully open during the test;
- type fluid encountered (oil, water, mud, etc.);
- volume and type of fluids injected to replace fluid bled;
- shut-in tubing pressure (from last shut-in);
- flowing tubing pressure;
- production rate (oil, gas and water);
- wellbore schematic (may reference the well file or include the actual schematic);
- water depth (subsea or hybrid);

Optional additional information that may be helpful includes the following:

- lease name;
- lease number;
- well API number;
- gas lift or injection (volume, pressure);
- pressure charts;
- reason for conducting the test;
- casing and tubing data (size, weight, grade, MIYP, collapse pressure);
- Maximum allowable annulus wellhead pressure;
- Date last bleed-down test conducted.

9.3.2 Shut in the Well and Monitor Pressure Drop

- test procedure (may reference a standard procedure or an individual well procedure);
- date;
- identification of person conducting the test;
- facility identification;
- well name;
- well type (fixed platform, subsea, hybrid, mud-line suspension);
- water depth (subsea and hybrid wells);
- wellbore schematic (optional, may reference a file copy);
- identification of casing being evaluated (size, weight and grade);
- pre-shut-in production rate (oil, gas, water);
- applied pressure information (type or reason, rate, pressure);
- time well is shut-in;
- time well is opened up for flow;
- pressure in the annulus being evaluated in one-hour increments beginning at the time the well is shut-in until the pressure either falls to zero psig or the well is opened up for flow;
- pressure at the end of the shut-in period;
- post-shut-in production rate (oil, gas, water);
- post-shut-in pressure in the annulus being evaluated in one-hour increments for a 24-hour period or until the pressure stabilizes;
- shut-in tubing pressure at the end of the shut-in period;
- flowing tubing pressure before the well is shut-in and the stabilized flowing tubing pressure after the well is returned to production.

9.3.3 Constant Production Rate and Decrease the Annular Pressure

- test procedure (may reference a standard procedure or an individual well procedure);
- date;
- identification of person conducting the test;
- facility identification;
- well name;
- well status (flowing, gas lift, shut-in, etc.);
- well type (fixed platform, subsea, hybrid, mud-line suspension);
- water depth (subsea wells or hybrid);

- wellbore schematic (optional, may reference a file copy);
- identification of casing being evaluated (size, weight and grade);
- production rate (oil, gas, water);
- applied pressure information (type or reason, rate, pressure);
- pressure in annulus being evaluated prior to bleed-down;
- amount of and type of wellbore fluids bled off;
- pressure in annulus being evaluated after the bleed-down in one-hour increments for 24 consecutive hours;
- shut-in tubing pressure (from last shut-in);
- flowing tubing pressure.

9.3.4 Constant Production Rate and Increase the Annular Pressure

- test procedure (may reference a standard procedure or an individual well procedure);
- date;
- identification of person conducting the test;
- facility identification;
- well name;
- well status (flowing, gas lift, shut-in, etc.);
- well type (fixed platform, subsea, hybrid, mud-line suspension);
- water depth (subsea or hybrid wells);
- wellbore schematic (optional, may reference a file copy);
- identification of casing being evaluated (size, weight and grade);
- production rate (oil, gas, water);
- applied pressure information (type or reason, rate, pressure);
- pressure in annulus being evaluated prior to raising the pressure;
- amount and type of fluid injected in annulus to raise the pressure;
- pressure in annulus being evaluated after the injection of fluid in one-hour increments for 24 consecutive hours;
- shut-in tubing pressure (from last shut-in);
- flowing tubing pressure.

9.3.5 Change the Production Rate

- test procedure (may reference a standard procedure or an individual well procedure);
- date;
- identification of person conducting the test;
- facility identification;
- well name;
- well status (flowing, gas lift, etc.);
- well type (fixed platform, subsea, hybrid, mud-line suspension);
- water depth (subsea or hybrid wells);
- wellbore schematic (optional, may reference a file copy);
- identification of annulus being evaluated;
- production rate prior to the test (oil, gas, water);
- applied pressure information (type or reason, rate, pressure);
- pressure in annulus being evaluated prior to changing the production rate;
- production rate after increase or decrease (oil, gas, water);
- pressure in annulus being evaluated after the production rate change in one-hour increments for 24 consecutive hours;
- flowing tubing pressure prior to production rate change;
- flowing tubing pressure after the production rate change;
- shut-in tubing pressure (from last shut-in);

9.4 MAWOP

The MAWOP for each annulus and the following input data used to calculate the MAWOP should be documented and maintained on either the platform or at the nearest field office consistent with the operator's corporate policy. Written records should meet the

minimum requirements of the applicable regulatory agency. An operator may find it helpful to develop a report form to be used by field personnel.

- date;
- identification of person calculating the MAWOP;
- well name;
- identification of annulus being evaluated;
- identification and minimum collapse pressure of the inner tubular (based on the minimum weight and grade present in the tubular string);
- identification and MIYP of the casing being evaluated (based on the minimum weight and grade present in the casing string);
- identification and MIYP of the next outer casing from the casing being evaluated (based on the minimum weight and grade present in the casing string);
- identification of any de-rating factors used for known casing wear, corrosion, etc.;
- calculated MAWOP.

10 Risk Analysis Considerations

Offshore wells that do not meet the criteria for managing annulus pressure using the criteria established in Section 3 of this Recommended Practice need to be handled on a case-by-case basis. As a part of the detailed evaluation of the annulus pressure, a risk assessment may be conducted in evaluating the potential for an undesirable event such as the loss of well control either at the surface or subsurface because of annular pressure. Risk analysis is the process of understanding (1) what undesirable things can happen, (2) how likely they are to happen, and (3) how severe the consequences may be. Risk assessment involves the process by which the results from risk analysis are considered against pre-determined acceptance criteria. In all cases, the risk assessment should consider the potential risk to personnel, property and the environment as a consequence of maintaining and/or mitigating annular pressure.

10.1 RISK ASSESSMENT TECHNIQUES

There are numerous risk assessment techniques that an operator may use in the evaluation of annular pressure. Risk assessment techniques may be either qualitative or quantitative and may be very basic or very detailed. The risk evaluation process can use any combination of basic, detailed or comparative assessments and as many iterations as necessary, provided that the analysts believe that such combination of techniques will support a conclusion.

The operator should choose an appropriate technique based on the following considerations:

- Data available for the assessment.
- Operator's familiarity with various techniques.
- The establishment of acceptance criteria (qualitative or quantitative).

If the risk assessment is to be provided to a governmental agency as part of the annular pressure management program, then the risk methodology and acceptance criteria need to be acceptable to the governmental agency.

Examples of qualitative risk assessment methods include the following:

- Hazard Identification (HAZID);
- Hazard and Operability (HAZOP);
- what-if;
- Failure Mode and Effects Analysis (FMEA).

Examples of quantitative risk assessment methods include the following:

- fault tree analysis;
- event tree analysis.

The acceptance criteria should be compatible with the chosen risk analysis technique. In many cases, a risk assessment matrix is established and used. In other cases, quantitative measures are established. Alternatively, comparative risk assessments may also be used to compare one situation with an alternative. For annular pressure, comparative risk assessment may be particularly useful

in determining if the risk of mitigating the pressure through a particular action such as a well intervention has more or less risk than maintaining the pressure at its current level.

10.2 HAZARD SCENARIOS

Risk considers, in part, the identification of various events that could occur and the likelihood of an event occurring. For annular pressure, the main event of concern is the loss of well control either to the environment or subsurface. The loss of well control could be either as a direct result of the annular pressure such as burst casing caused by the annular pressure, or could be from a secondary cause such as a mudslide severing a casing string under annular pressure. If mitigating annular pressure is being evaluated, events related to the mitigation work, such as pulling the completion string, should be considered. After the events have been identified, the likelihood of the event occurring must be determined. This may be either qualitative (i.e., high, medium or low) or quantitative (i.e., 3×10^{-6}), depending of the type of hazard assessment being conducted. The hazard scenarios need to be considered on a case-by-case basis for the well and annulus involved.

10.3 CONSEQUENCE CONSIDERATIONS

Risk considers, in part, the consequence should an event identified in 10.2 occur, regardless of the likelihood of the event occurring. Consequences to personnel, the environment and property should all be evaluated. These need to be considered on a case-by-case basis for the well being evaluated.

10.3.1 Risk to Personnel Considerations

Subsea wells and wells located on unmanned platforms generally are considered to have a relatively low risk to personnel, since personnel are not typically located near the wells on an ongoing basis. For subsea wells, the location of the well relative to a manned structure should be considered. For wells on unmanned platforms, the frequency personnel visit the platform should be considered.

On manned platforms, the following should be considered:

- number of personnel on the platform (availability of personnel to be injured);
- oil and gas flow rate and pressure (potential for fire);
- H₂S release;
- Simultaneous operations.

In the event a well intervention to mitigate annular pressure is being evaluated, the following should be considered:

- number of personnel at the location (availability of personnel to be injured);
- oil and gas flow rate and pressure (potential for fire);
- H₂S release;
- Simultaneous operations;
- Safety of personnel for operations related to the well intervention, but not directly related to annular pressure;
- Loss of well control related to the well intervention, but not directly related to annular pressure.

10.3.2 Environmental Impact Considerations

The factors discussed below influence the potential environmental impact in the event of a release to the environment.

- oil, gas or injection well;
- characteristics of the product released (dispersion capability, evaporation, etc.);
- capacity of the well to flow;
- expected flow rate decrease caused by collapsing formation or depletion of reserves in the event of loss of well control;
- near environmentally sensitive live reef areas, resort beaches, oyster beds, etc.

10.3.3 Property Damage Considerations

The following factors discussed below should be considered:

- Damage to structure caused by fire.
- Damage to structure caused by release at the seafloor (erosion, subsidence, etc.).

- Loss/deferred production from well with annular pressure.
- Loss/deferred production from wells in the vicinity.
- Reservoir damage.
- Charging up of formations in the vicinity.

10.4 RISK REFERENCES

There are many good references on risk assessment methodology. A few examples are given below:

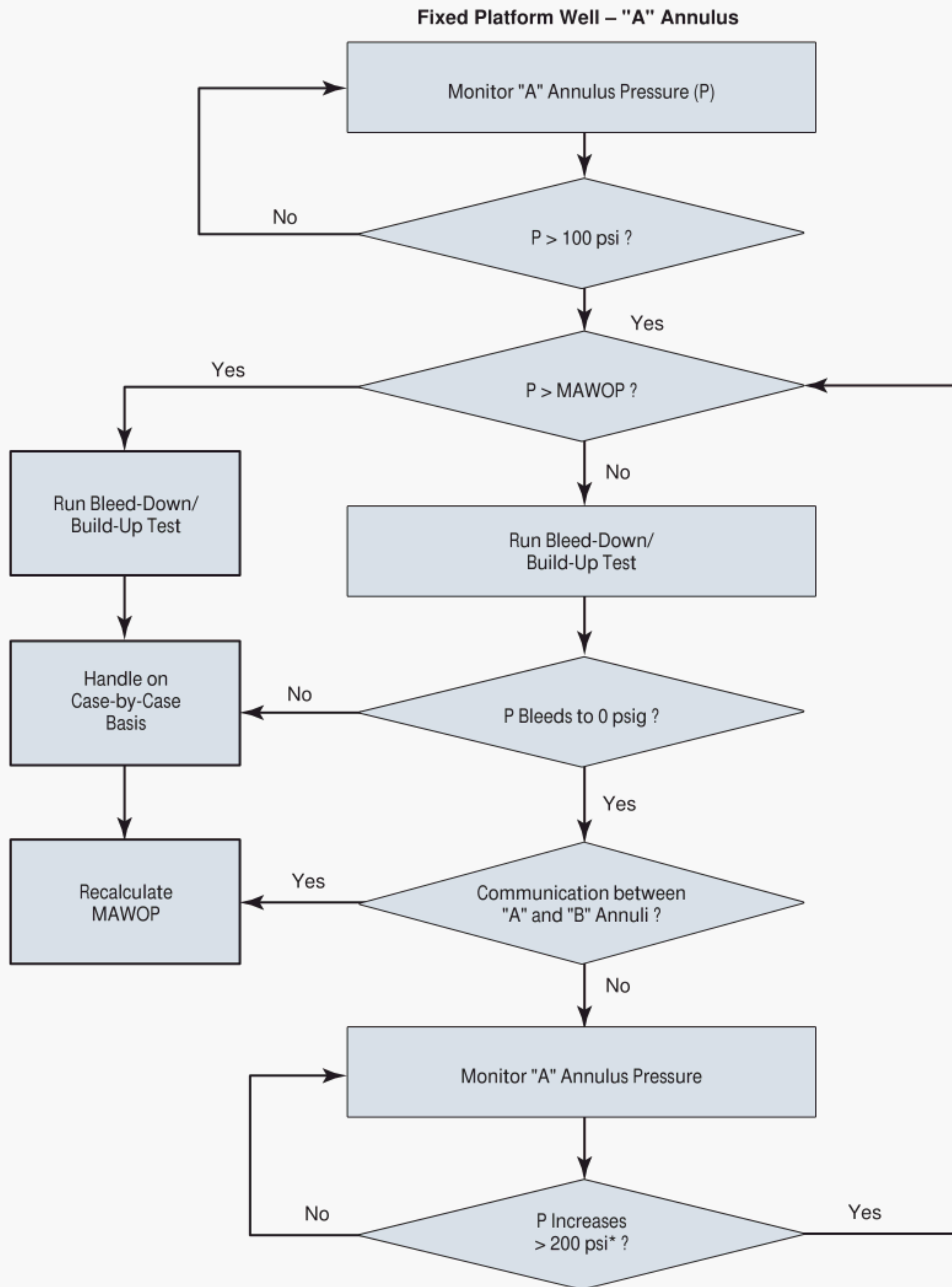
- API RP 14J, *Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities*, American Petroleum Institute
- *Guidance Notes on Risk Assessment Application for Marine and Offshore Oil and Gas Industries*, American Bureau of Shipping, 2003.
- *Guidance Notes on Review and Approval of Novel Concepts*, American Bureau of Shipping, 2003.
- *Classification Based on Performance Criteria Determined From Risk Assessment Methodology*, DNV, 2000

11 Appendix A—Annular Pressure Management Flowcharts And Examples

11.1 FIXED PLATFORM WELLS

11.1.1 Evaluation of the “A” Annulus, No Thermal Pressure or Operator–Imposed Pressure

11.1.1.1 Flow Chart



*Based on the Operator's Management Plan or Regulator Requirements.

11.1.1.2 Examples

1. Use the MAWOP Calculations in 12.2.1, Well #1

		Measured Pressure	MAWOP
		PSIG	PSIG
Prod Tubing	3.5", 12.9#, L-80	NA	NA
"A" Annulus	7 ⁵ / ₈ ", 39#, Q-125	59	7,088
"B" Annulus	10 ³ / ₄ ", 55.5#, P-110	0	2,760
"C" Annulus	13 ³ / ₈ ", 68#, K-55	0	1,725
"D" Annulus	18 ⁵ / ₈ ", 87.5#, K-55	0	675

Action Required: The "A" annulus pressure is less than 100 psig. Continue to monitor pressures in all annuli.

2. Use the MAWOP Calculations in 12.1.1, Well #1

		Measured Pressure	MAWOP
		PSIG	PSIG
Prod Tubing	3.5", 12.9#, L-80	NA	NA
"A" Annulus	7 ⁵ / ₈ ", 39#, Q-125	240	7,088
"B" Annulus	10 ³ / ₄ ", 55.5#, P-110	0	2,760
"C" Annulus	13 ³ / ₈ ", 68#, K-55	0	1,725
"D" Annulus	18 ⁵ / ₈ ", 87.5#, K-55	0	675

Required Action: The "A" annulus pressure is less than MAWOP. Run bleed down/build up test on "A" annulus while monitoring other annuli. "A" annulus bleeds to 0 psi with no pressure response in the other annuli. Continue to monitor pressures in all annuli.

3. Use the MAWOP Calculations in 12.1.1, Well #1

		Measured Pressure	MAWOP
		PSIG	PSIG
Prod Tubing	3.5", 12.9#, L-80	NA	NA
"A" Annulus	7 ⁵ / ₈ ", 39#, Q-125	8,000	7,088
"B" Annulus	10 ³ / ₄ ", 55.5#, P-110	0	2,760
"C" Annulus	13 ³ / ₈ ", 68#, K-55	0	1,725
"D" Annulus	18 ⁵ / ₈ ", 87.5#, K-55	0	675

Required Action: The "A" annulus pressure is greater than MAWOP. Run bleed-down/build-up test on "A" annulus while monitoring other annuli. Handle on a case-by-case basis.

4. Use the MAWOP Calculations in 12.1.1, Well #1

		Measured Pressure	MAWOP
		PSIG	PSIG
Prod Tubing	3.5", 12.9#, L-80	NA	NA
"A" Annulus	7 ⁵ / ₈ ", 39#, Q-125	5,000	7,088
"B" Annulus	10 ³ / ₄ ", 55.5#, P-110	0	2,760
"C" Annulus	13 ³ / ₈ ", 68#, K-55	0	1,725
"D" Annulus	18 ⁵ / ₈ ", 87.5#, K-55	0	675

Required Action: The "A" annulus pressure is less than MAWOP. Run bleed-down/build-up test on "A" annulus while monitoring other annuli. "A" annulus bleeds to 500 psi with no pressure response in other annuli. Handle on a case-by-case basis.

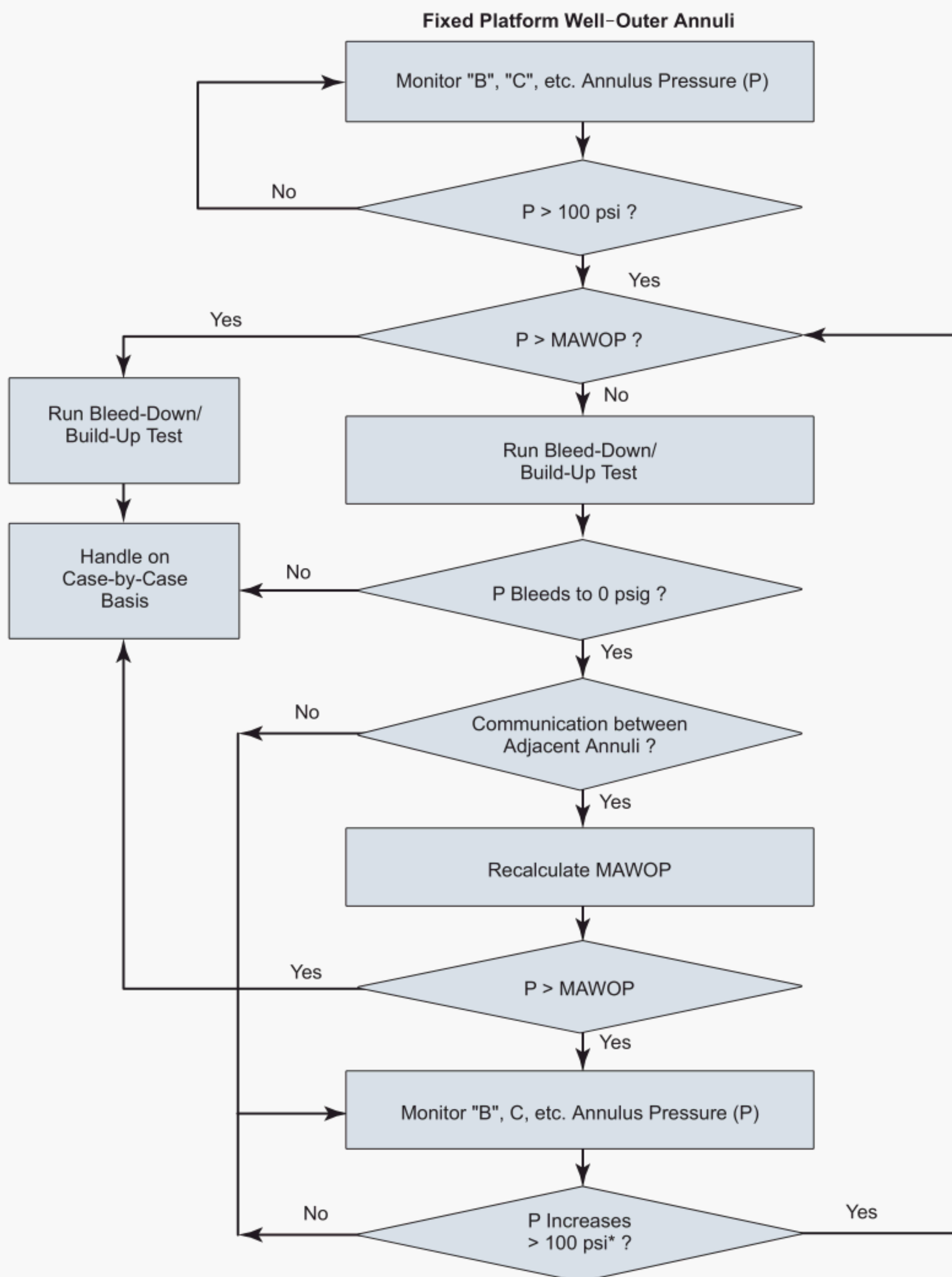
5. Use the MAWOP Calculations in 12.2.2, Well #2

		Measured Pressure	MAWOP
		PSIG	PSIG
Prod Tubing	3.5", 12.9#, L-80	NA	N/A
"A" Annulus	7 ⁵ / ₈ ", 39#, Q-125	2,000	2,760
"B" Annulus	10 ³ / ₄ ", 55.5#, P-110	1,000	2,760
"C" Annulus	13 ³ / ₈ ", 68#, K-55	0	1,725
"D" Annulus	18 ⁵ / ₈ ", 87.5#, K-55	0	675

Required Action: The "A" and "B" annulus pressures are less than the original MAWOP. Run bleed-down/build-up test on "A" annulus while monitoring the other annuli. "A" annulus bleeds to 0 psi and "B" annulus decreases to 750 psi indicating communication between the "A" and "B" annuli. Run bleed-down/build-up test on "B" annulus. Recalculate MAWOP based on the communication between the "A" and "B" annuli. Handle on a case-by-case basis.

11.1.2 Evaluation of the Outer Annulus (B, C, D, etc.), No Thermal Pressure or Operator-Imposed Pressure

11.1.2.1 Flow Chart



*Based on the Operator's Management Plan or Regulator Requirements.

11.1.2.2 Examples

1. Use the MAWOP Calculations in Section 12.2.1, Well #1

		Measured Pressure	MAWOP
		PSIG	PSIG
Prod Tubing	3.5", 12.9#, L-80	NA	NA
"A" Annulus	7 ⁵ / ₈ ", 39#, Q-125	0	7,088
"B" Annulus	10 ³ / ₄ ", 55.5#, P-110	0	2,760
"C" Annulus	13 ³ / ₈ ", 68#, K-55	49	1,725
"D" Annulus	18 ⁵ / ₈ ", 87.5#, K-55	0	675

Required Action: The "B", "C", and "D" annulus pressure are all less than 100 psig. Continue to monitor pressure in all annuli.

2. Use the MAWOP Calculations in 12.2.1, Well #1

		Measured Pressure	MAWOP
		PSIG	PSIG
Prod Tubing	3.5", 12.9#, L-80	NA	NA
"A" Annulus	7 ⁵ / ₈ ", 39#, Q-125	0	7,088
"B" Annulus	10 ³ / ₄ ", 55.5#, P-110	0	2,760
"C" Annulus	13 ³ / ₈ ", 68#, K-55	0	1,725
"D" Annulus	18 ⁵ / ₈ ", 87.5#, K-55	500	675

Required Action: The "D" annulus pressure is less than MAWOP. Run bleed-down/build-up test in "D" annulus while monitoring for pressure response in other annuli. "D" annulus pressure bleeds to 0 psig and no pressure response is observed in the other annuli. Continue to monitor all annuli.

3. Use the MAWOP Calculations in 12.1.1, Well #1

		Measured Pressure	MAWOP
		PSIG	PSIG
Prod Tubing	3.5", 12.9#, L-80	NA	N/A
"A" Annulus	7 ⁵ / ₈ ", 39#, Q-125	0	7,088
"B" Annulus	10 ³ / ₄ ", 55.5#, P-110	0	2,760
"C" Annulus	13 ³ / ₈ ", 68#, K-55	1,000	1,725
"D" Annulus	18 ⁵ / ₈ ", 87.5#, K-55	0	675

Required Action: The "C" annulus pressure is less than MAWOP. Run bleed-down/build-up test on "C" annulus while monitoring the other annuli. "C" annulus bleeds to 0 psi and no pressure response is observed in other annuli. Continue to monitor all annuli.

4. Use the MAWOP Calculations in 12.1.1, Well #1

		Measured Pressure	MAWOP
		PSIG	PSIG
Prod Tubing	3.5", 12.9#, L-80	NA	NA
"A" Annulus	7 ⁵ / ₈ ", 39#, Q-125	0	7,088
"B" Annulus	10 ³ / ₄ ", 55.5#, P-110	0	2,760
"C" Annulus	13 ³ / ₈ ", 68#, K-55	1,000	1,725
"D" Annulus	18 ⁵ / ₈ ", 87.5#, K-55	0	675

Required Action: The "C" annulus pressure is less than MAWOP. Run bleed-down/build-up test on "C" annulus while monitoring the other annuli. "C" annulus bleeds to 400 psi and no pressure response is observed in other annuli. Handle on a case-by-case basis.

5. Use the MAWOP Calculations in 12.2.3, Well #1

		Measured Pressure	MAWOP	Recalculated MAWOP
		PSIG	PSIG	PSIG
Prod Tubing	3.5", 12.9#, L-80	NA	NA	NA
"A" Annulus	7 ⁵ / ₈ ", 39#, Q-125	0	7,088	2,760
"B" Annulus	10 ³ / ₄ ", 55.5#, P-110	1,000	2,760	1,312
"C" Annulus	13 ³ / ₈ ", 68#, K-55	1,000	1,725	1,312
"D" Annulus	18 ⁵ / ₈ ", 87.5#, K-55	300	675	492

Required Action: The "B", "C" and "D" annulus pressures are less than the original MAWOP. Run bleed-down/build-up test on "B" annulus while monitoring the other annuli. "B" annulus bleeds to 0 psig and the "C" annulus decreases to 500 psig indicating communication between the "B" and "C" annuli. The "C" annulus bleeds to 0 psig. The "D" annulus bleeds to 0 psig. Recalculate MAWOP based on the communication between the "B" and "C" annuli. The "B", "C" and "D" annulus pressures are less than the recalculated MAWOP. Continue to monitor the "B", "C" and "D" annuli pressures.

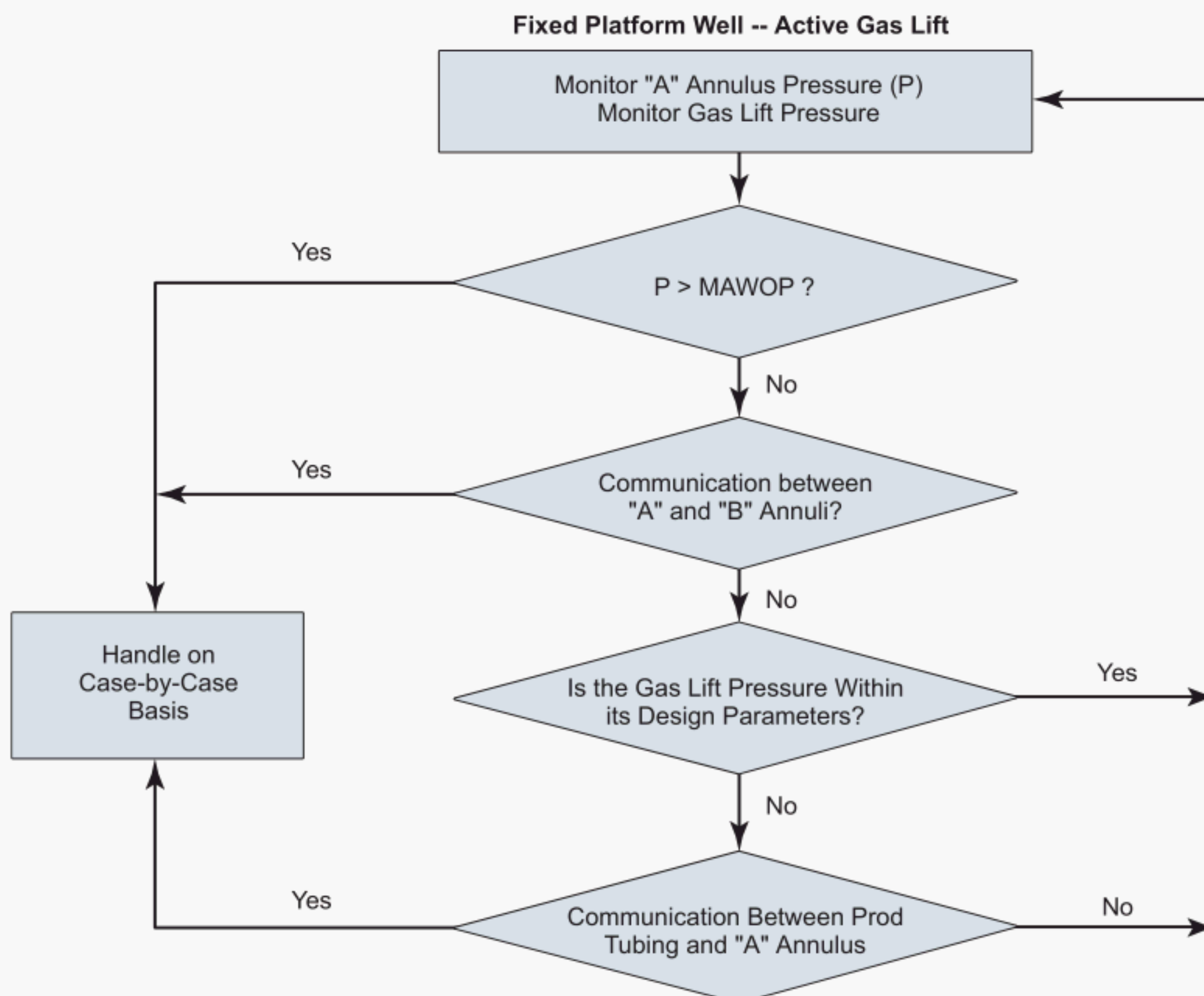
6. Use the MAWOP Calculations in 12.2.3, Well #1

		Measured Pressure	MAWOP	Recalculated MAWOP
		PSIG	PSIG	PSIG
Prod Tubing	3.5", 12.9#, L-80	NA	NA	NA
"A" Annulus	7 ⁵ / ₈ ", 39#, Q-125	0	7,088	2,760
"B" Annulus	10 ³ / ₄ ", 55.5#, P-110	1,500	2,760	1,312
"C" Annulus	13 ³ / ₈ ", 68#, K-55	1,500	1,725	1,312
"D" Annulus	18 ⁵ / ₈ ", 87.5#, K-55	300	675	492

Required Action: The "B", "C" and "D" annulus pressures are less than the original MAWOP. Run bleed-down/build-up test on "B" annulus while monitoring the other annuli. "B" annulus bleeds to 0 psig and the "C" annulus decreases to 500 psig indicating communication between the "B" and "C" annuli. The "C" annulus bleeds to 0 psig. The "D" annulus bleeds to 0 psig. Recalculate MAWOP based on the communication between the "B" and "C" annuli. The "B", "C" and "D" annulus pressures are greater than the recalculated MAWOP. Handle on a case-by-case basis.

11.1.3 Active Gas Lift, Evaluation of the “A” Annulus

11.1.3.1 Flow Chart



If the gas lift well is shut-in for an extended period of time or the gas lift gas is shut-off, this flow chart is not applicable. See Chart 11.1.1.1.

11.1.3.2 Examples

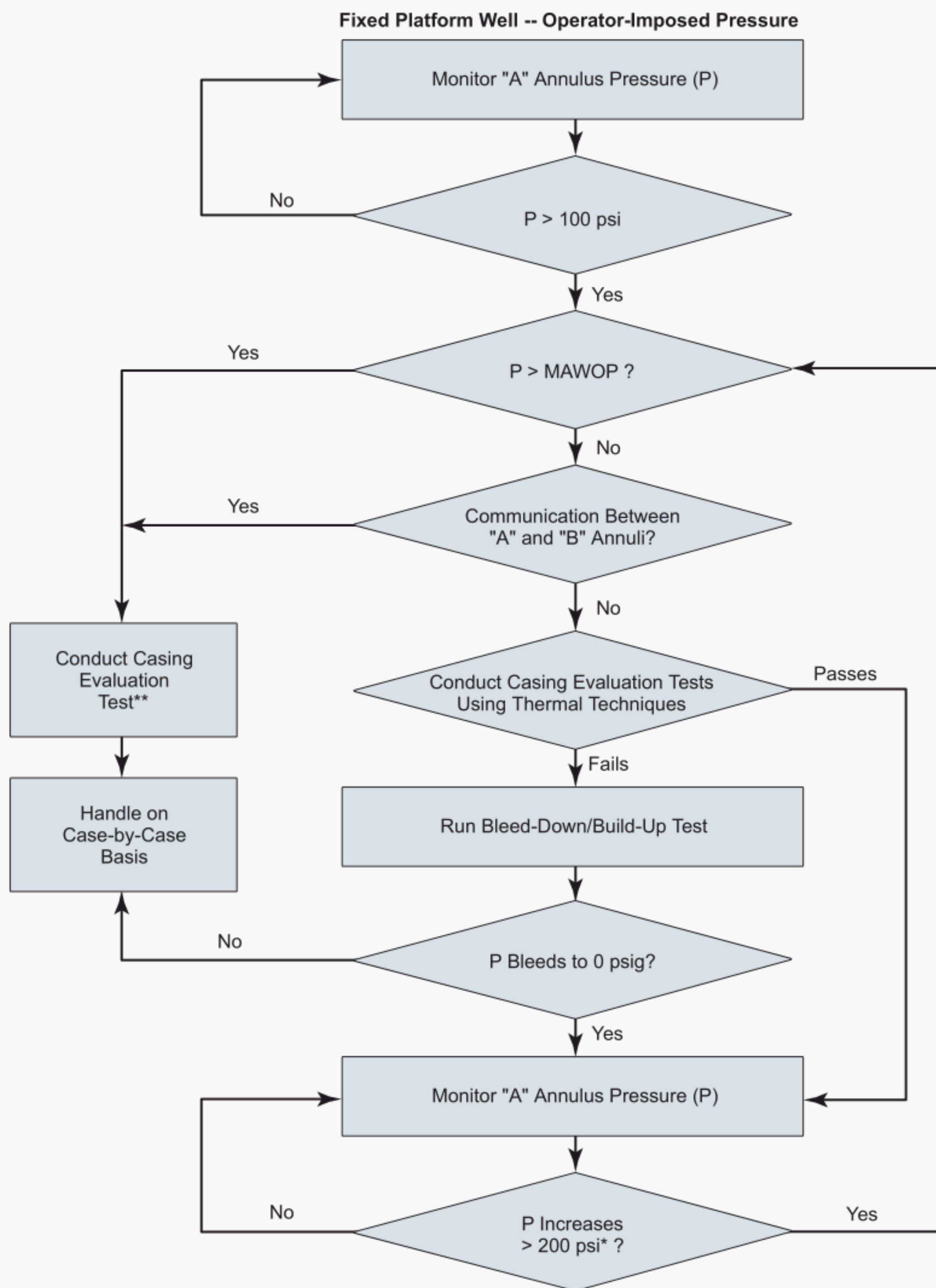
1. Use the MAWOP Calculations in 12.2.1, Well #1, the pressure in the “A” annulus is gas lift pressure.

		Measured Pressure	MAWOP
		PSIG	PSIG
Prod Tubing	3.5", 12.9#, L-80	NA	NA
“A” Annulus	7 ⁵ / ₈ ", 39#, Q-125	1,500	7,088
“B” Annulus	10 ³ / ₄ ", 55.5#, P-110	0	2,760
“C” Annulus	13 ³ / ₈ ", 68#, K-55	1,000	1,725
“D” Annulus	18 ⁵ / ₈ ", 87.5#, K-55	0	675

Required Action: The “A” annulus is less than MAWOP. There is no communication between the “A” and “B” annuli because the “B” annulus pressure is 0 psig. Confirm gas lift pressure is within its design parameters. If true, continue to monitor all annuli. If gas lift pressure is not within its design parameters, check for communication between the production tubing and “A” annulus. If communication exists, handle on a case-by-case basis. Evaluate the “C” annulus pressure using flow chart 11.1.2.1, “Fixed Platform Well-Outer Annuli”. Should the well become shut-in or the gas lift gas is shut-off, then the “A” annulus pressure will need to be evaluated using flow chart 11.1.1.1, “Fixed Platform Well-“A” Annulus.

11.1.4 Operator-Imposed Pressure, Evaluation of the "A" Annulus

11.1.4.1 Flow Chart



*Based on Operator's Management Plan or Regulatory Requirements.

**The casing evaluation test may use thermal techniques or a bleed-down/build-up test, whichever is appropriate.

11.1.4.2 Examples

1. Use the MAWOP Calculations in 12.2.1, Well #1, pressure on the “A” annulus is operator-imposed pressure.

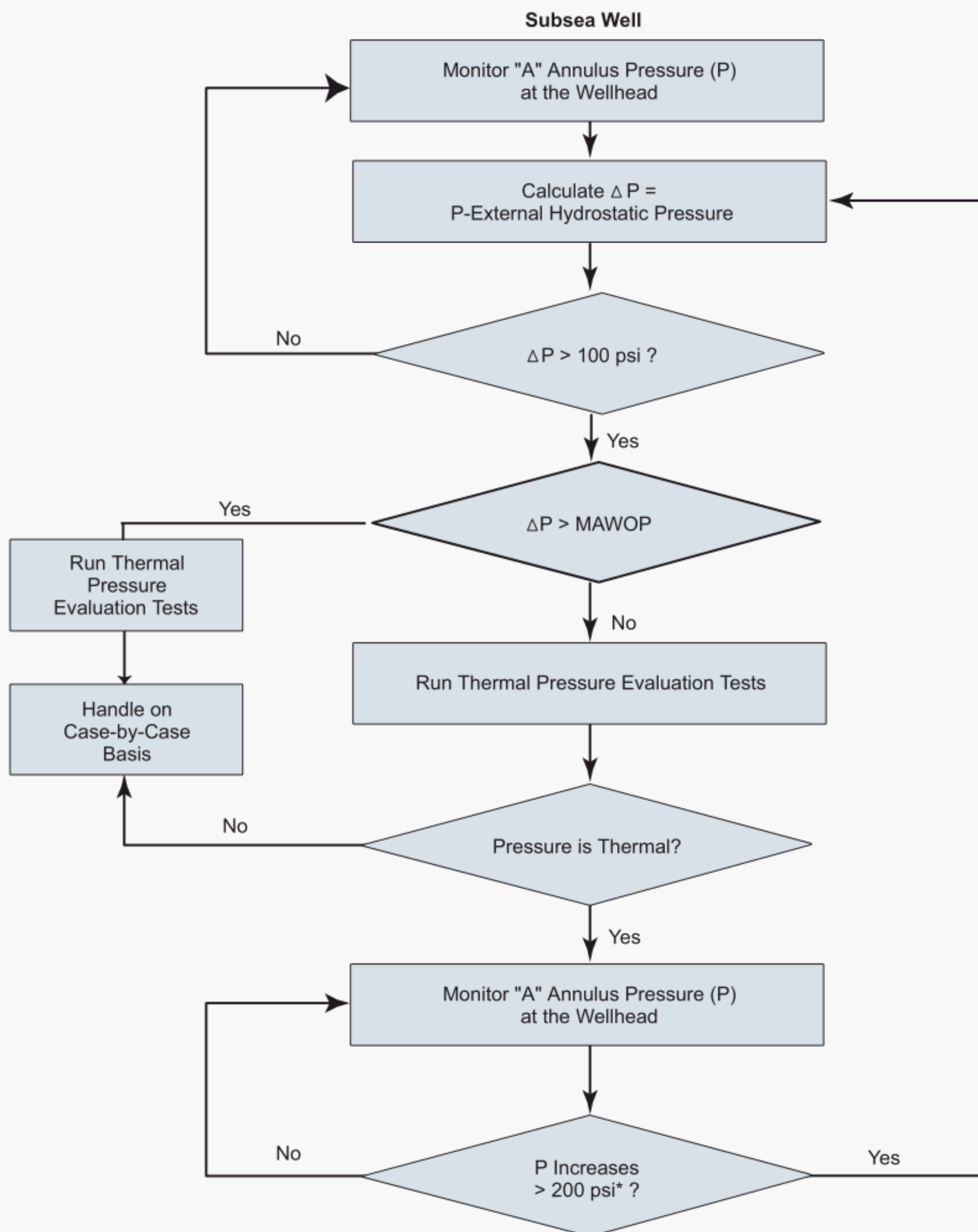
		Measured Pressure	MAWOP
		PSIG	PSIG
Prod Tubing	3.5", 12.9#, L-80	NA	NA
“A” Annulus	7 ⁵ / ₈ ", 39#, Q-125	1500	7,088
“B” Annulus	10 ³ / ₄ ", 55.5#, P-110	0	2,760
“C” Annulus	13 ³ / ₈ ", 68#, K-55	0	1,725
“D” Annulus	18 ⁵ / ₈ ", 87.5#, K-55	0	675

Required Action: The “A” annulus pressure is less than MAWOP. Communication does not exist between the “A” and “B” annuli because the “B” annulus pressure is 0 psig. Evaluate the “A” annulus with one of the techniques for evaluating thermal pressure. If the thermal evaluation test is passed, then continue to monitor the annulus pressure. If the thermal evaluation test is failed, indicating that the pressure may not be solely operator-imposed, then run a bleed-down/build-up test. If the pressure bleeds to 0 psig, then continue monitoring the annulus pressure. If the pressure does not bleed to 0 psig, this indicates that there is a communication problem and the pressure was not solely operator-imposed. Handle on a case-by-case basis.

11.2 SUBSEA WELL

11.2.1 Evaluation of the 'A' Annulus

11.2.1.1 Flow Chart



*Based on Operator's Management Plan or Regulatory Requirements.

11.2.1.2 Examples

1. Use the MAWOP calculations in 12.3.1, Subsea Well #1

		Measured Pressure	External Hydrostatic	ΔP	MAWOP
		PSIG	PSIG	PSIG	PSIG
Prod Tubing	3.5", 12.9#, L-80	NA	NA	NA	NA
"A" Annulus	7 ⁵ / ₈ ", 39#, Q-125	7500	2500	5000*	5,450
"B" Annulus	10 ³ / ₄ ", 55.5#, P-110	NA	NA	NA	NA
"C" Annulus	13 ³ / ₈ ", 68#, K-55	NA	NA	NA	NA

* Pressure is the difference between the measured pressure and the external hydrostatic pressure.

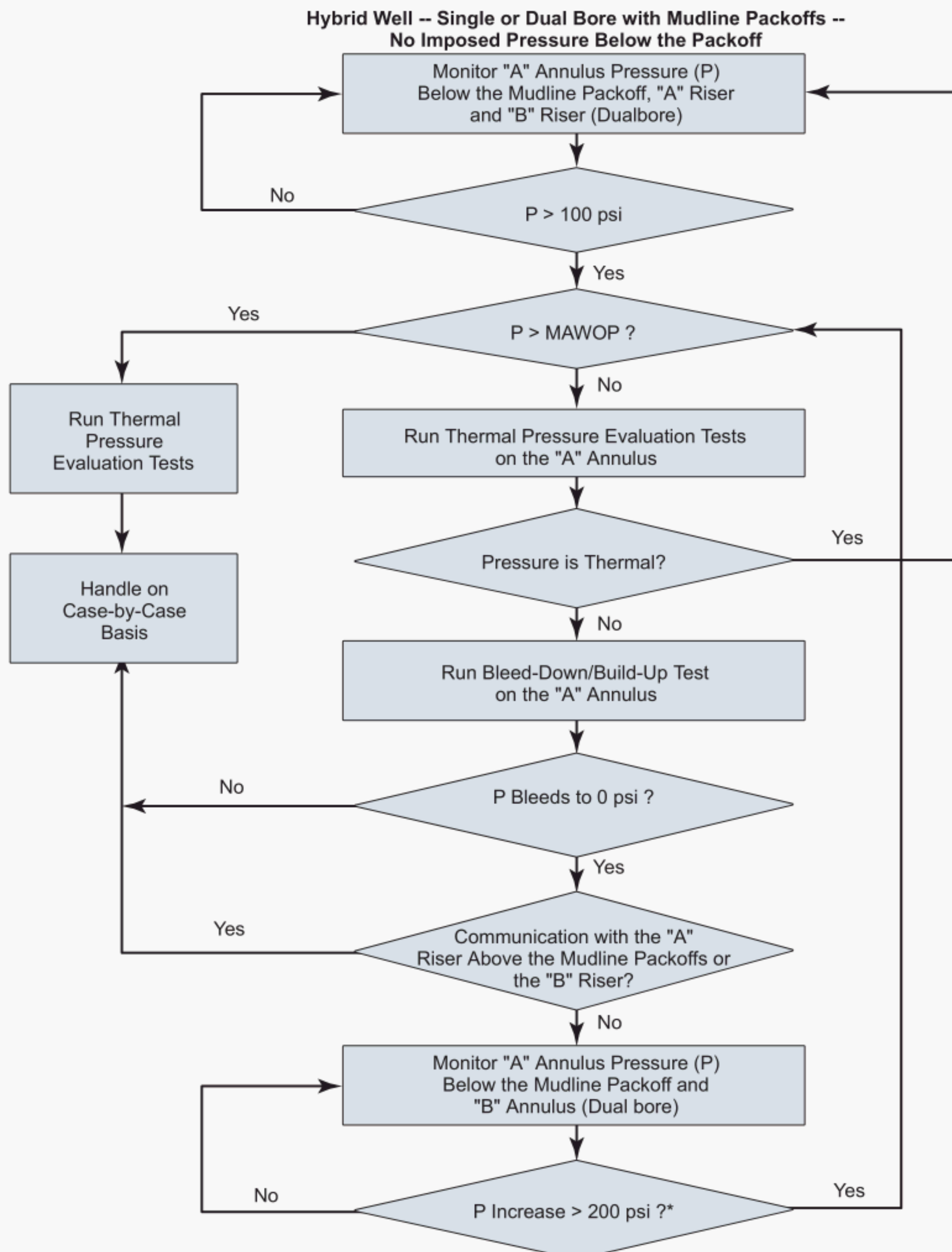
Required Action: The pressure difference between the external hydrostatic pressure and the measured pressure in the "A" annulus is less than MAWOP. Evaluate the "A" annulus using one of the thermal evaluation tests. If the pressure is thermal, continue to monitor the annulus. If the test is failed (pressure is not entirely thermal), handle on a case-by-case basis.

11.3 HYBRID WELL

11.3.1 Single or Dual Bore with "A" Annulus Mudline Packoff (Packer)-No Imposed Pressure Below the Packoff, Evaluation of the "A" and "B" Annulus Pressure Below the Mudline Packoff.

11.3.1.1 Flow Chart

The "A" and "B" riser evaluation should follow Flow Chart 11.3.2.1 or 11.3.3.1 later in this Appendix. In this example, the "A" riser is completely isolated from the "A" annulus below the mudline. The "B" riser may or may not be in direct communication with the "B" annulus below the mudline, depending on the well construction. The pressure measurements are made on the "A" riser, the "A" annulus and the "B" riser.



*Based on Operator's Management Plan or Regulatory Requirements.

11.3.1.2 Examples

1. Use MAWOP calculations in 12.4.1, Hybrid Well #1, 150 psig of operator-imposed pressure in the “A” riser and in the “B” riser/annulus. The construction of this well has the “B” riser in direct communication with the “B” annulus. The “B” annulus pressure was not actually measured; it was set equal to the “B” riser pressure.

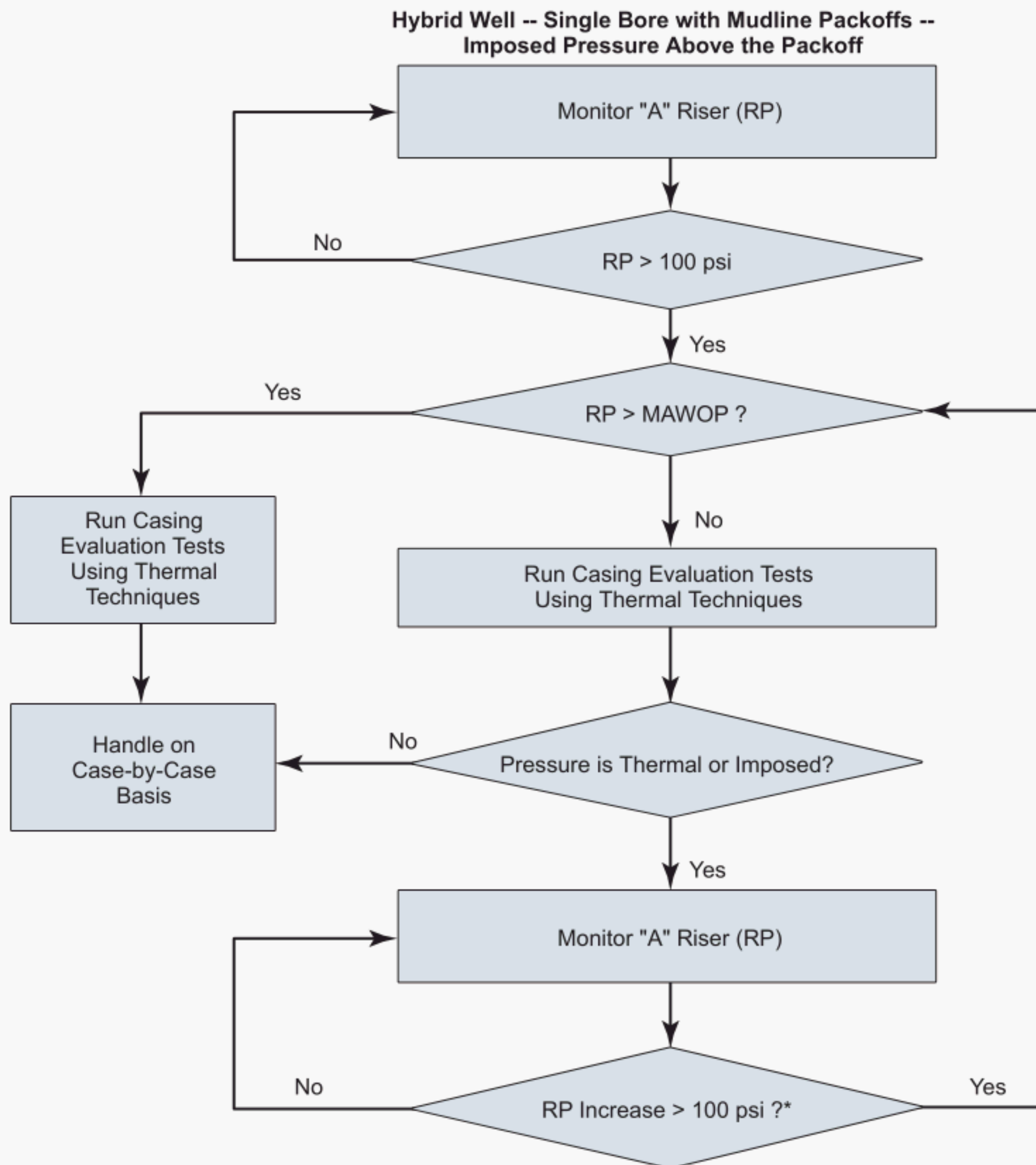
		Measured Pressure	MAWOP
		PSIG	PSIG
Prod Tubing	4.5", 12.6#, P-110		NA
“A” Riser	9 ⁷ / ₈ ", 62.8#, P-110	150	4,304
“B” Riser	13 ³ / ₈ ", 72#, X-80	150	1,614
“A” Annulus	9 ⁷ / ₈ ", 62.8#, Q-125	1000	6,908
“B” Annulus	13 ⁵ / ₈ ", 88.2#, Q-125	150	1,614
“C” Annulus	20", 169#, K-55	NA	NA

Required Action: The “A” annulus, “A” riser and “B” riser pressures are all below MAWOP. Evaluate the “A” annulus and “B” riser/annuli using thermal evaluation techniques. If the “A” annulus pressure is thermal and no communication exists between the “A” annulus and “A” riser or the “B” riser/annulus, continue to monitor the annuli. If the pressure is either not entirely thermal or communication with the “A” riser or the “B” riser/annulus exists, handle on a case-by-case basis. If the pressure is either not entirely thermal or communication with the “A” riser or the “B” riser/annulus exists, handle on a case-by-case basis. Evaluate the “A” and “B” riser pressures using Flow Chart 11.3.3.1.

11.3.2 Single Bore with Mudline Packoff (Packer)- Imposed Pressure Above the Packoff, Evaluation of the "A" Riser Pressure

11.3.2.1 Flow Chart

In this example, the "A" riser is completely isolated from the "A" annulus below the packoff. There is not a "B" riser and the "B" annulus below the mudline is isolated in the high pressure housing. The only annular pressure measurement points are on the "A" riser and the "A" annulus below the mudline packoff.



*Based on Operator's Management Plan or Regulatory Requirements.

11.3.2.2 Examples

1. Use MAWOP calculations from 12.4.4, Hybrid Well #4, pressure in the “A” riser is operator-imposed.

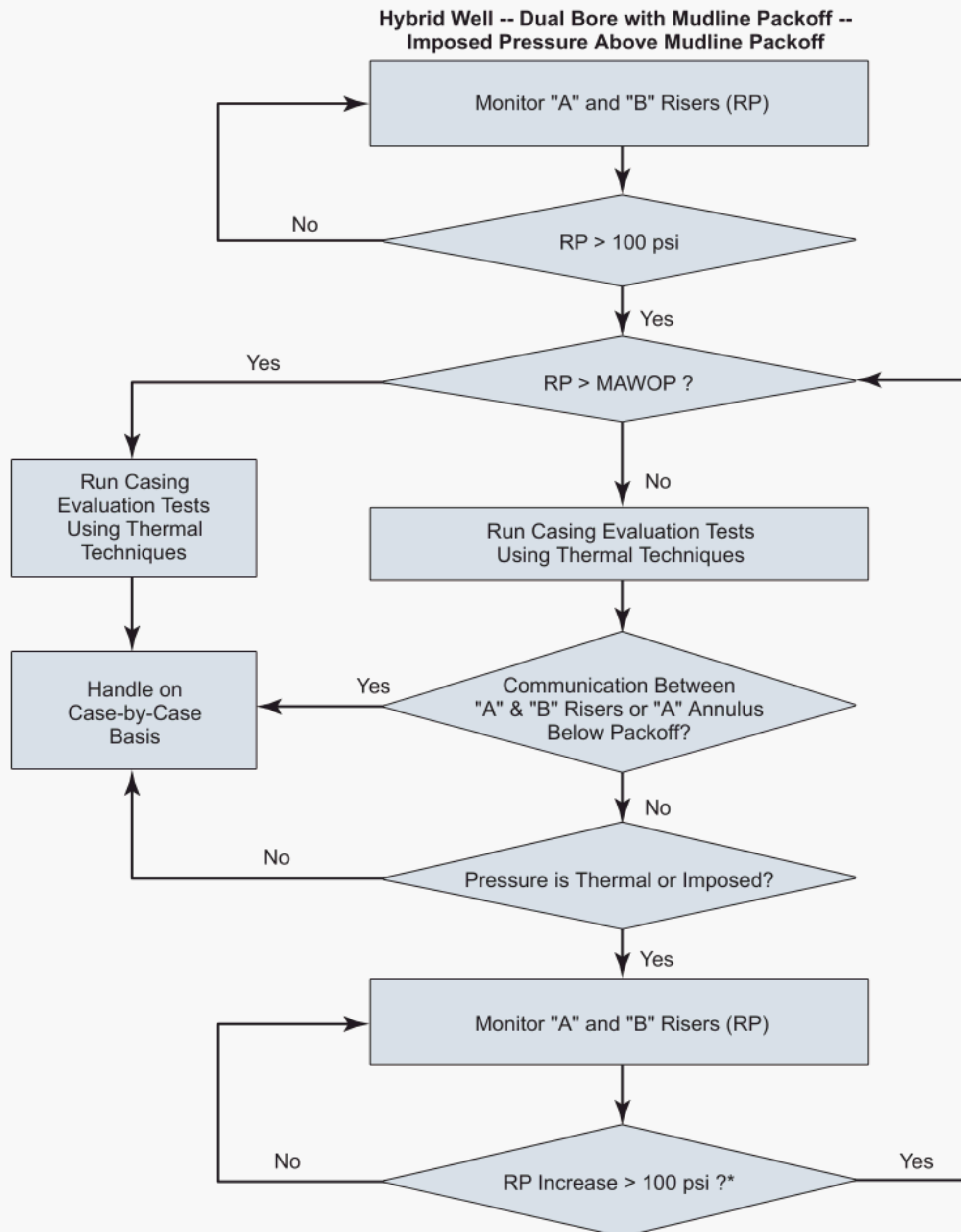
		Measured Pressure	MAWOP
		PSIG	PSIG
Prod Tubing	4.5", 12.6#, P-110		NA
“A” Riser	9 ⁷ / ₈ ", 62.8#, P-110	150	3,654
“A” Annulus	9 ⁷ / ₈ ", 62.8#, Q-125	1,500	6,920
“B” Annulus	13 ⁵ / ₈ ", 88.2#, Q-125	NA	NA
“C” Annulus	20", 169#, K-55		NA

Required Action: The “A” riser pressure is less than MAWOP. Run casing evaluation test on the “A” riser using thermal pressure techniques to demonstrate that all of the pressure is either operator-imposed or thermal pressure. If the test shows that the pressure is either operator-imposed or thermal (or a combination of the two), then continue to monitor the annulus. If the test shows that the pressure is not all thermal or operator-imposed, then handle on a case-by-case basis. Evaluate the “A” annulus pressure below the packoff using Flow Chart 11.3.1.1.

11.3.3 Dual Bore with Mudline Packoff (Packer)- Imposed Pressure on the “A” and “B” Risers, Evaluation of the “A” and “B” Risers.

11.3.3.1 Flow Chart

In this example, the “A” riser is completely isolated from the “A” annulus below the mudline. The “B” riser may or may not be in direct communication with the “B” annulus below the mudline, depending on well construction. The pressure measurements are made on the “A” riser, the “A” annulus and the “B” riser.



*Based on Operator's Management Plan or Regulatory Requirements.

11.3.3.2 Examples

1. Use MAWOP calculations from 12.4.2, Hybrid Well #2

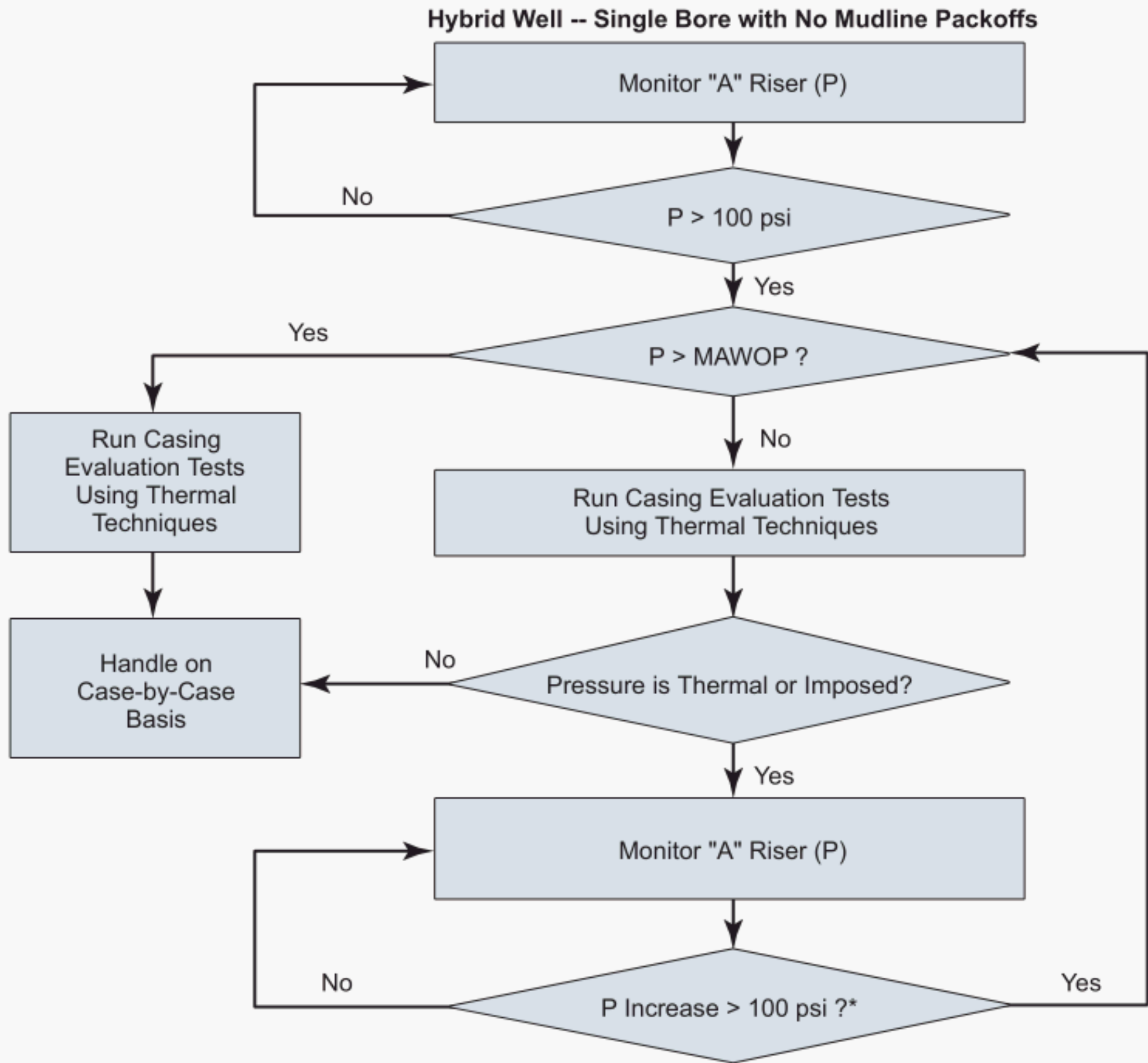
		Measured Pressure	MAWOP
		PSIG	PSIG
Prod Tubing	4.5", 12.6#, P-110		NA
"A" Riser	9 ⁷ / ₈ ", 62.8#, P-110	150	4,304
"B" Riser	13 ³ / ₈ ", 72#, X-80	150	1,614
"A" Annulus	9 ⁷ / ₈ ", 62.8#, Q-125	1,500	6,908
"B" Annulus	13 ⁵ / ₈ ", 88.2#, Q-125	NA	NA
"C" Annulus	20", 169#, K-55		NA

Required Action: The "A" and "B" riser pressures are less than MAWOP. Evaluate the "A" and "B" risers using thermal pressure evaluation techniques to determine if the pressure is all operator-imposed or thermal while monitoring the annulus not being tested. Check for pressure response indicating communication between risers or the "A" annulus below the packoff. If the pressure is all operator-imposed or thermal (or a combination of the two), continue to monitor the annuli. If the pressure is not all operator-imposed or thermal, or there is communication between the risers or the "A" annulus below the packoff, then handle on a case-by-case basis. Evaluate the "A" annulus pressure using Flow Chart 11.3.1.1.

11.3.4 Single Bore with No Mudline Packoff (Packer), Evaluation of the “A” Riser/Annulus

11.3.4.1 Flow Chart

In this example, the “A” riser is in direct communication with the “A” annulus below the mudline. There is not a “B” riser and the “B” annulus below the mudline is isolated in the high pressure housing. The only annular pressure measurement point is on the “A” riser.



*Based on Operator's Management Plan or Regulatory Requirements.

11.3.4.2 Examples

1. Use MAWOP calculations in 12.4.5, Hybrid Well #5

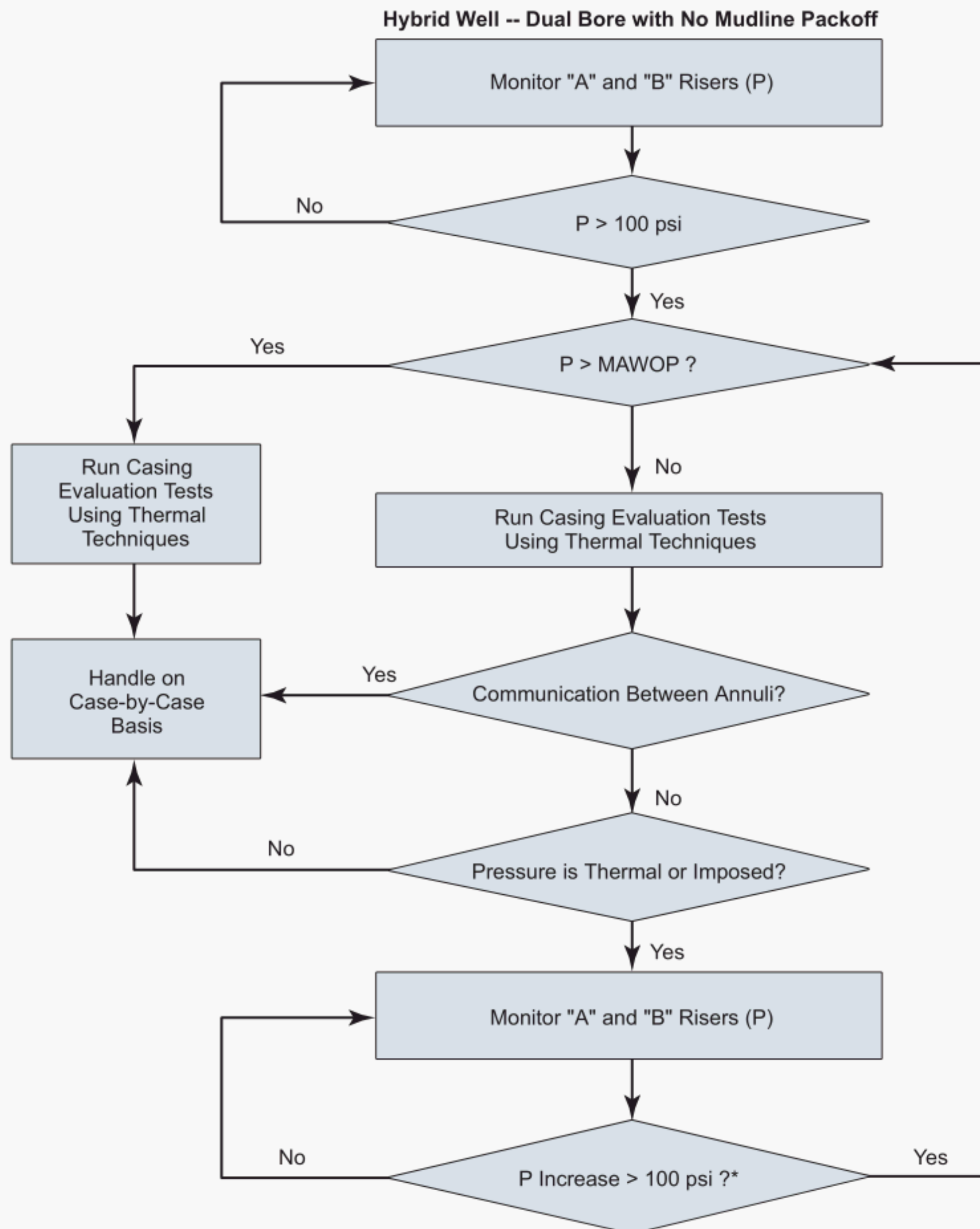
		Measured Pressure	MAWOP
		PSIG	PSIG
Prod Tubing	4.5", 12.6#, P-110		NA
"A" Riser	9 ⁷ / ₈ ", 62.8#, P-110	1,500	3,654
"A" Annulus	9 ⁷ / ₈ ", 62.8#, Q-125	1,500	3,654
"B" Annulus	13 ⁵ / ₈ ", 88.2#, Q-125	NA	NA
"C" Annulus	20", 169#, K-55	NA	NA

Required Action: The "A" riser/annulus pressure is less than MAWOP. Run casing evaluation test on the "A" riser/annulus using thermal pressure techniques. If the pressure is thermal or operator-imposed, continue to monitor the annulus. If the pressure is not entirely thermal or operator-imposed, handle on a case-by case basis.

11.3.5 Dual Bore with No Mudline Packoff (Packer), Evaluation of the “A” Riser/Annulus and the “B” Riser/Annulus

11.3.5.1 Flow Chart

In this example, the “A” riser is in direct communication with the “A” annulus below the mudline. The “B” riser may or may not be in direct communication with the “B” annulus below the mudline, depending on the well construction. The only annular pressure measurement points are on the “A” riser and the “B” riser.



*Based on Operator's Management Plan or Regulatory Requirements.

11.3.5.2 Examples

1. Use MAWOP calculations from 12.4.3, Hybrid Well #3

In this example, the “A” riser is in direct communication with the “A” annulus below the mudline. The “B” riser is in direct communication with the “B” annulus below the mudline. The only annular pressure measurement points are on the “A” riser and the “B” riser.

		Measured Pressure	MAWOP
		PSIG	PSIG
Prod Tubing	4.5", 12.6#, P-110		NA
“A” Riser	9 ⁷ / ₈ ", 62.8#, P-110	1,500	4,304
“B” Riser	13 ³ / ₈ ", 72#, X-80	1,000	1,614
“A” Annulus	9 ⁷ / ₈ ", 62.8#, Q-125	1,500*	4,304
“B” Annulus	13 ⁵ / ₈ ", 88.2#, Q-125	1,000*	1,614
“C” Annulus	20", 169#, K-55	NA	NA

* Pressure actually measured in the “A” and “B” risers at the surface.

Required Action: The “A” riser/annulus and “B” riser/annulus pressures are less than MAWOP. Evaluate the “A” riser/annulus and “B” riser/annulus using thermal pressure evaluation techniques. Check for pressure response in the annulus not being tested for communication. If the pressure is thermal or operator-imposed, continue monitoring the annuli. If the pressure is either not entirely thermal or operator-imposed, or if communication between the annuli exist, handle on a case-by-case basis.

11.3.6 Mudline Suspension Wells

The appropriate flow chart for either fixed platform wells or subsea wells should be utilized for mudline suspension wells. Example MAWOP calculations are given in 12.5.

12 Appendix B—Example MAWOP Calculations

12.1 DEFINITION:

The MAWOP for the annulus being evaluates is the lesser of the following:

- 50% of the MIYP of the pipe body for the casing or production riser string being evaluated (30% for the last casing or production string in the well); or
- 80% of the MIYP of the pipe body of the next outer casing or production riser string; or
- 75% of the MCP of the inner tubular pipe body

12.2 FIXED PLATFORM WELLS: MAWOP

12.2.1 Fixed Platform Well #1: No Communication Between Annuli

The MAWOP is controlled by 80% MIYP of the next outer casing for the “A” and “B” annuli.

		MIYP	Collapse	50% MIYP	30% MIYP	75% Collapse	80% MIYP	MAWOP	% MIYP
		PSIG	PSIG	PSIG	PSIG	PSIG	PSIG	PSIG	
Prod Tubing	3.5", 12.9#, L-80	15,000	15,310	NA	NA	11,483	NA	NA	NA
“A” Annulus	7 ⁵ / ₈ ", 39#, Q-125	14,340	12,060	7,170	NA	9,045	11,472	7,088	49%
“B” Annulus	10 ³ / ₄ ", 55.5#, P-110	8,860	5,950	4,430	NA	4,463	7,088	2,760	31%
“C” Annulus	13 ³ / ₈ ", 68#, K-55	3,450	1,950	1,725	NA	1,463	2,760	1,725	50%
“D” Annulus	18 ⁵ / ₈ ", 87.5#, K-55	2,250	630	1,125	675	473	1,800	675	30%

12.2.2 Fixed Platform Well #2: Communication Between “A” and “B” annuli

The MAWOP for the “A” annulus will be set at the MAWOP calculated for the “B” annulus since it is the first competent barrier moving outward from the “A” annulus.

		MIYP	Collapse	50% MIYP	30% MIYP	75% Collapse	80% MIYP	MAWOP	% MIYP
		PSIG	PSIG	PSIG	PSIG	PSIG	PSIG	PSIG	
Prod Tubing	3.5", 12.9#, L-80	15,000	15,310	NA	NA	11,483	NA	NA	NA
“A” Annulus	7 ⁵ / ₈ ", 39#, Q-125	14,340	12,060	7,170	NA	9,045	11,472	2,760	19%
“B” Annulus	10 ³ / ₄ ", 55.5#, P-110	8,860	5,950	4,430	NA	4,463	7,088	2,760	31%
“C” Annulus	13 ³ / ₈ ", 68#, K-55	3,450	1,950	1,725	NA	1,463	2,760	1,725	50%
“D” Annulus	18 ⁵ / ₈ ", 87.5#, K-55	2,250	630	1,125	675	473	1,800	675	30%

12.2.3 Fixed Platform Well #3: Communication Between “B” and “C” annuli

The MAWOP for the “B” annulus will be set at the MAWOP calculated for the “C” annulus since it is the first competent barrier outward from the “B” annulus. The MAWOP of the “A” annulus is also affected and is based on 80% of the MIYP of the “C” annulus, not the “B” annulus.

		MIYP	Collapse	50% MIYP	30% MIYP	75% Collapse	80% MIYP	MAWOP	% MIYP
		PSIG	PSIG	PSIG	PSIG	PSIG	PSIG	PSIG	
Prod Tubing	2 7/8", 4.7#, L-80	11,200	11,780	NA	NA	8,835	NA	NA	NA
“A” Annulus	7 ⁵ / ₈ ", 33.7#, P-110	10,860	7,870	5,430	NA	5,903	8,688	2,760	25%
“B” Annulus	10 ³ / ₄ ", 45.5#, K-55	3,580	2,090	1,790	NA	1,568	2,864	1,312	37%
“C” Annulus	13 ³ / ₈ ", 68#, K-55	3,450	1,950	1,725	NA	1,463	2,760	1,312	38%
“D” Annulus	16", 65#, H-40	1,640	630	820	492	473	1,312	492	30%

12.3 SUBSEA WELLS: MAWOP

12.3.1 Subsea Well #1: “A” Annulus Only

All annuli except the “A” annulus are sealed in the high pressure wellhead housing; therefore, only the “A” annulus has a MAWOP value.

		MIYP	Collapse	50% MIYP	30% MIYP	75% Collapse	80% MIYP	MAWOP	% MIYP
		PSIG	PSIG	PSIG	PSIG	PSIG	PSIG	PSIG	
Prod Tubing	3.5", 9.3#, L-80	10,160	10,530	NA	NA	7,898	NA	NA	NA
“A” Annulus	9 ⁵ / ₈ ", 53.5#, P-110	10,900	7,950	5,450	NA	5,963	8,720	5,450	50%
“B” Annulus	13 ³ / ₈ ", 72#, P-110	7,400	2,880	3,700	NA	2,160	5,920	NA	NA
“C” Annulus	20", 169#, K-55	3,910	2,500	1,955	1,173	1,875	3,128	NA	NA

12.4 HYBRID WELLS: MAWOP

12.4.1 Hybrid Well #1: Dual Bore Riser, Mudline Packoff in the “A” Annulus

The hybrid well has an “A” and “B” riser. The production casing runs through the subsea wellhead and is tied back below the mudline. A mudline packer isolates the “A” riser from the “A” annulus below the mudline. Therefore, there is a separate MAWOP for the “A” riser and the “A” annulus. Since the production casing runs through the subsea wellhead, the “B” riser is in direct communication with “B” annulus below the subsea wellhead. Therefore, the “B” riser and “B” annulus have the same MAWOP. All other annuli are isolated in the subsea wellhead and do not have a MAWOP.

		MIYP	Collapse	50% MIYP	30% MIYP	75% Collapse	80% MIYP	MAWOP	% MIYP
		PSIG	PSIG	PSIG	PSIG	PSIG	PSIG	PSIG	
Prod Tubing	4.5", 12.6#, P-110	11,590	9,210	NA	NA	6,908	NA	NA	NA
“A” Riser	9 ⁷ / ₈ ", 62.8#, P-110	12,180	10,290	6,090	NA	7,718	9,744	4,304	35%
“B” Riser	13 ³ / ₈ ", 72#, X-80	5,380	2,670	2,690	1,614	2,003	4,304	1,614	30%
“A” Annulus	9 ⁷ / ₈ ", 62.8#, Q-125	13,840	11,140	6,920	NA	8,355	11,072	6,908	50%
“B” Annulus	13 ⁵ / ₈ ", 88.2#, Q-125	10,030	4,800	5,015	NA	3,600	8,024	1,614	16%
“C” Annulus	20", 169#, K-55	3,910	2,500	1,955	1,173	1,875	3,128	NA	NA

12.4.2 Hybrid Well #2: Dual Bore Riser, Mudline Packoff in the “A” Annulus, No Communication Between the “B” Riser and “B” Annulus

The hybrid well has “A” and “B” risers which are attached to the subsea wellhead. A mudline packer isolates the “A” riser from the “A” annulus below the mudline. Therefore, there is a separate MAWOP for the “A” riser and the “A” annulus. Since the “B” riser is attached to the subsea wellhead, there is no communication between the “B” riser and “B” annulus and the “B” annulus is isolated in the subsea wellhead. Therefore, there is a MAWOP for the “B” riser, but not for the “B” annulus. All other annuli are isolated in the subsea wellhead and do not have a MAWOP.

		MIYP	Collapse	50% MIYP	30% MIYP	75% Collapse	80% MIYP	MAWOP	% MIYP
		PSIG	PSIG	PSIG	PSIG	PSIG	PSIG	PSIG	
Prod Tubing	4.5", 12.6#, P-110	11,590	9,210	NA	NA	6,908	NA	NA	NA
"A" Riser	9 ⁷ / ₈ ", 62.8#, P-110	12,180	10,290	6,090	NA	7,718	9,744	4,304	35%
"B" Riser	13 ³ / ₈ ", 72#, X-80	5,380	2,670	2,690	1,614	2,003	4,304	1,614	30%
"A" Annulus	9 ⁷ / ₈ ", 62.8#, Q-125	13,840	11,140	6,920	NA	8,355	11,072	6,908	50%
"B" Annulus	13 ⁵ / ₈ ", 88.2#, Q-125	10,030	4,800	5,015	NA	3,600	8,024	NA	NA%
"C" Annulus	20", 169#, K-55	3,910	2,500	1,955	1,173	1,875	3,128	NA	NA

12.4.3 Hybrid Well #3: Dual Bore Riser With No Isolation at the Mudline or at the Subsea Wellhead

The hybrid well has "A" and "B" risers which are attached to the subsea wellhead. The production casing runs through the subsea wellhead and is tied back below the mudline. No mudline packer isolates the "A" riser from the "A" annulus below the mudline. Therefore, the "A" riser and "A" annulus have the same MAWOP. Since the production casing runs through the subsea wellhead, the "B" riser is in direct communication with "B" annulus below the subsea wellhead. Therefore, the "B" riser and "B" annulus have the same MAWOP. All other annuli are isolated in the subsea wellhead and do not have a MAWOP.

		MIYP	Collapse	50% MIYP	30% MIYP	75% Collapse	80% MIYP	MAWOP	% MIYP
		PSIG	PSIG	PSIG	PSIG	PSIG	PSIG	PSIG	
Prod Tubing	4.5", 12.6#, P-110	11,590	9,210	NA	NA	6,908	NA	NA	NA
"A" Riser	9 ⁷ / ₈ ", 62.8#, P-110	12,180	10,290	6,090	NA	7,718	9,744	4,304	35%
"B" Riser	13 ³ / ₈ ", 72#, X-80	5,380	2,670	2,690	1,614	2,003	4,304	1,614	30%
"A" Annulus	9 ⁷ / ₈ ", 62.8#, Q-125	13,840	11,140	6,920	NA	8,355	11,072	4,304	31%
"B" Annulus	13 ⁵ / ₈ ", 88.2#, Q-125	10,030	4,800	5,015	NA	3,600	8,024	1,614	16%
"C" Annulus	20", 169#, K-55	3,910	2,500	1,955	1,173	1,875	3,128	NA	NA

12.4.4 Hybrid Well #4: Single Bore Riser With Mudline Packoff

The hybrid well has only an "A" riser. A mudline packer isolates the "A" riser from the "A" annulus below the mudline. Therefore, there is a separate MAWOP for the "A" riser and the "A" annulus. All other annuli are isolated in the subsea wellhead and do not have a MAWOP.

		MIYP	Collapse	50% MIYP	30% MIYP	75% Collapse	80% MIYP	MAWOP	% MIYP
		PSIG	PSIG	PSIG	PSIG	PSIG	PSIG	PSIG	
Prod Tubing	4.5", 12.6#, P-110	11,590	9,210	NA	NA	6,908	NA	NA	NA
"A" Riser	9 ⁷ / ₈ ", 62.8#, P-110	12,180	10,290	6,090	3,654	7,718	9,744	3,654	30%
"A" Annulus	9 ⁷ / ₈ ", 62.8#, Q-125	13,840	11,140	6,920	NA	8,355	11,072	6,920	50%
"B" Annulus	13 ⁵ / ₈ ", 88.2#, Q-125	10,030	4,800	5,015	NA	3,600	8,024	NA	NA
"C" Annulus	20", 169#, K-55	3,910	2,500	1,955	1,173	1,875	3,128	NA	NA

12.4.5 Hybrid Well #5: Single Bore Riser Without Mudline Packoff

The hybrid well has only an “A” riser with no isolation between the “A” riser and the “A” annulus. Therefore, the MAWOP is the same for the “A” riser and the “A” annulus. All other annuli are isolated in the subsea wellhead and do not have a MAWOP.

		MIYP	Collapse	50% MIYP	30% MIYP	75% Collapse	80% MIYP	MAWOP	% MIYP
		PSIG	PSIG	PSIG	PSIG	PSIG	PSIG	PSIG	
Prod Tubing	4.5", 12.6#, P-110	11,590	9,210	NA	NA	6,908	NA	NA	NA
“A” Riser	9 ⁷ / ₈ ", 62.8#, P-110	12,180	10,290	6,090	3,654	7,718	9,744	3,654	30%
“A” Annulus	9 ⁷ / ₈ ", 62.8#, Q-125	13,840	11,140	6,920	NA	8,355	11,072	3,654	26%
“B” Annulus	13 ⁵ / ₈ ", 88.2#, Q-125	10,030	4,800	5,015	NA	3,600	8,024	NA	NA
“C” Annulus	20", 169#, K-55	3,910	2,500	1,955	1,173	1,875	3,128	NA	NA

12.5 MUDLINE SUSPENSION WELLS

12.5.1 Mudline Suspension Well #1: Dry Tree Platform Well

The 7", 9⁵/₈" and 20" casing were tied back to a surface wellhead and tree. Therefore, the “A” and “B” annulus were tied back to the surface, but the “C” annulus at the surface contained the 13³/₈" and 16" open casing tops.

		MIYP	Collapse	50% MIYP	30% MIYP	75% Collapse	80% MIYP	MAWOP	% MIYP
		PSIG	PSIG	PSIG	PSIG	PSIG	PSIG	PSIG	
Prod Tubing	2 ⁷ / ₈ ", 7.9#, L-80	13,440	13,890	NA	NA	10,418	NA	NA	NA
“A” Annulus	7", 35#, S-95	11,830	11,650	5,915	NA	8,738	9,464	5,915	50%
“B” Annulus	9 ⁵ / ₈ ", 53.5#, S-95	9,410	8,850	4,705	NA	6,638	7,528	1,928	20%
	13 ³ / ₈ ", 72#, S-95	6,390	3,470	3,195	NA	2,603	5,112	NA	NA
	16", 109#, K-55	3,950	2,560	1,975	NA	1,920	3,160	NA	NA
“C” Annulus	20", 106#, K-55	2,410	770	1,205	723	578	1,928	723	30%

12.5.2 Mudline Suspension Well #2: Subsea Well

The 7" and 9⁵/₈" are tied back to a mudline conversion subsea tree. Therefore, the “A” and “B” annulus were tied back to the sub-sea wellhead and tree. All remaining annuli are open to the seafloor and therefore do not have a MAWOP.

		MIYP	Collapse	50% MIYP	30% MIYP	75% Collapse	80% MIYP	MAWOP	% MIYP
		PSIG	PSIG	PSIG	PSIG	PSIG	PSIG	PSIG	
Prod Tubing	2 ⁷ / ₈ ", 7.9#, L-80	13,440	13,890	NA	NA	10,418	NA	NA	NA
"A" Annulus	7", 35#, S-95	11,830	11,650	5,915	NA	8,738	9,464	5,915	50%
"B" Annulus	9 ⁵ / ₈ ", 53.5#, S-95	9,410	8,850	4,705	2,823	6,638	7,528	2,823	30%
	13 ³ / ₈ ", 72#, S-95	6,390	3,470	3,195	NA	2,603	5,112	NA	NA
	16", 109#, K-55	3,950	2,560	1,975	NA	1,920	3,160	NA	NA

12.5.3 Mudline Suspension Well #3: Subsea Well

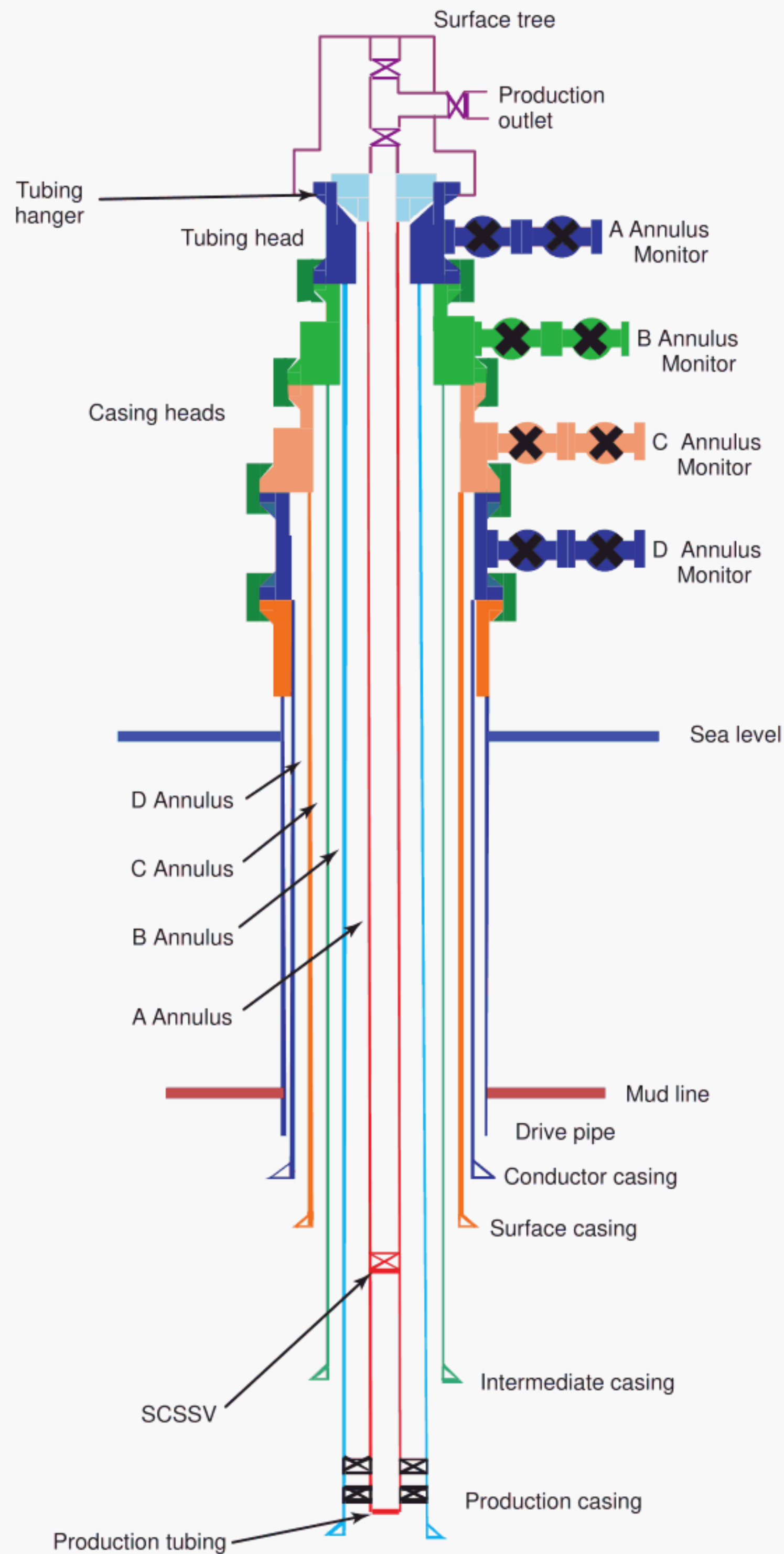
Only the 7" was tied back to a mudline conversion subsea tree. Therefore, the "A" annulus was tied back to the subsea wellhead and tree. All remaining annuli are open to the seafloor and therefore do not have a MAWOP.

		MIYP	Collapse	50% MIYP	30% MIYP	75% Collapse	80% MIYP	MAWOP	% MIYP
		PSIG	PSIG	PSIG	PSIG	PSIG	PSIG	PSIG	
Prod Tubing	2 ⁷ / ₈ ", 7.9#, L-80	13,440	13,890	NA	NA	10,418	NA	NA	NA
"A" Annulus	7", 35#, S-95	11,830	11,650	5,915	3,549	8,738	9,464	3,549	30%
	9 ⁵ / ₈ ", 53.5#, S-95	9,410	8,850	4,705	NA	6,638	7,528	NA	NA
	13 ³ / ₈ ", 72#, S-95	6,390	3,470	3,195	NA	2,603	5,112	NA	NA
	16", 109#, K-55	3,950	2,560	1,975	NA	1,920	3,160	NA	NA

13 Appendix C—Wellbore Sketches

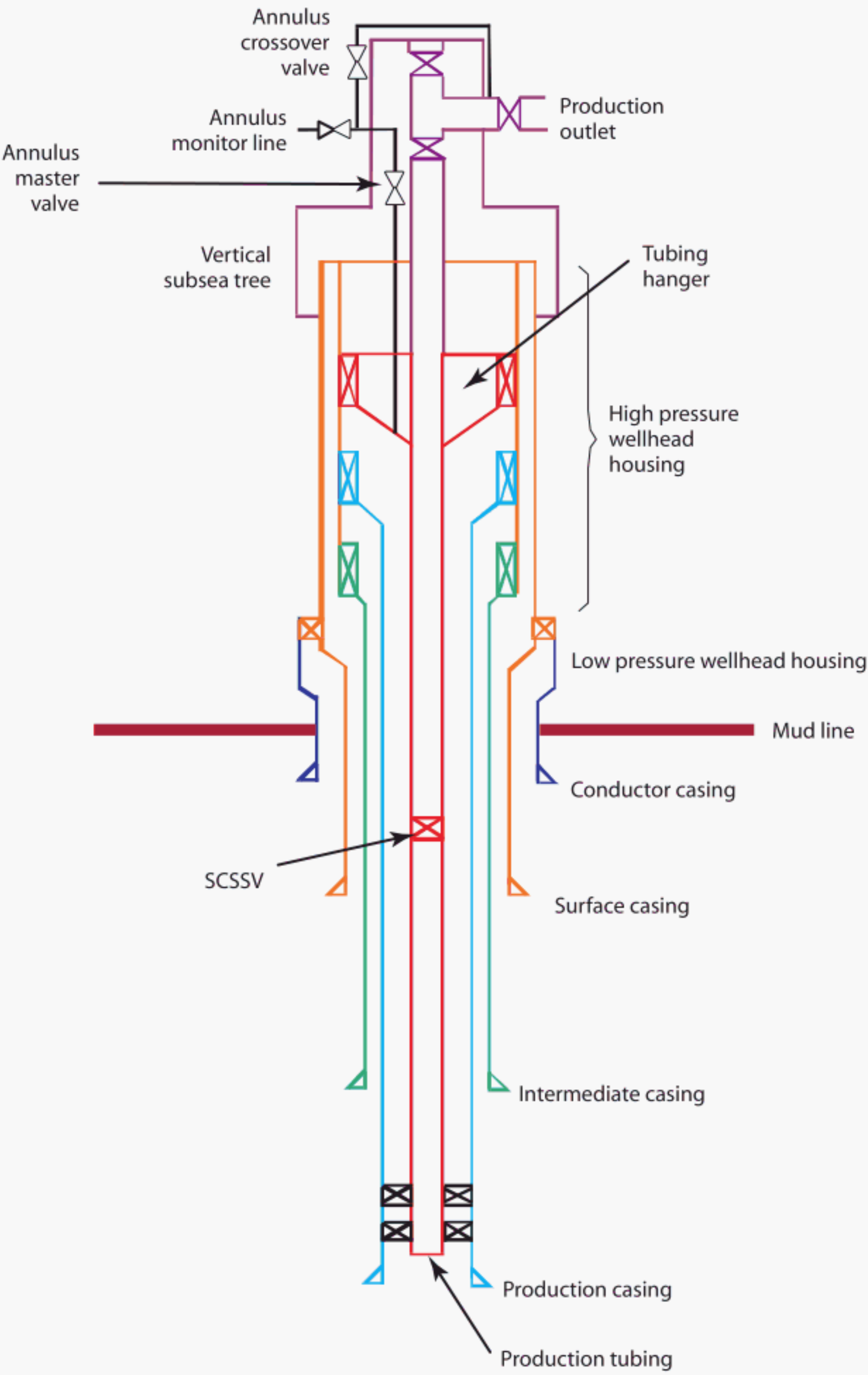
13.1 FIXED PLATFORM WELLS

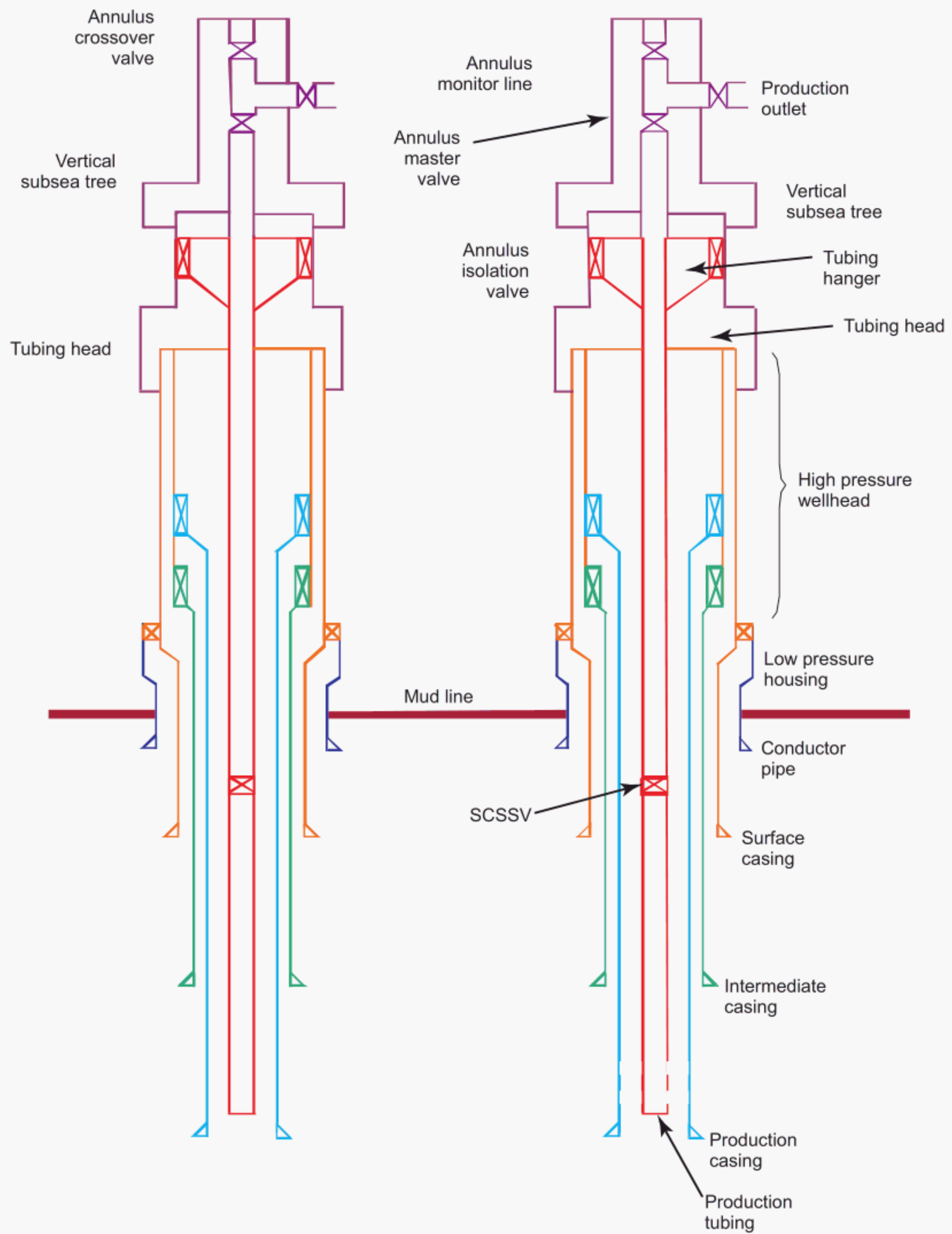
13.1.1 Four String Production Riser



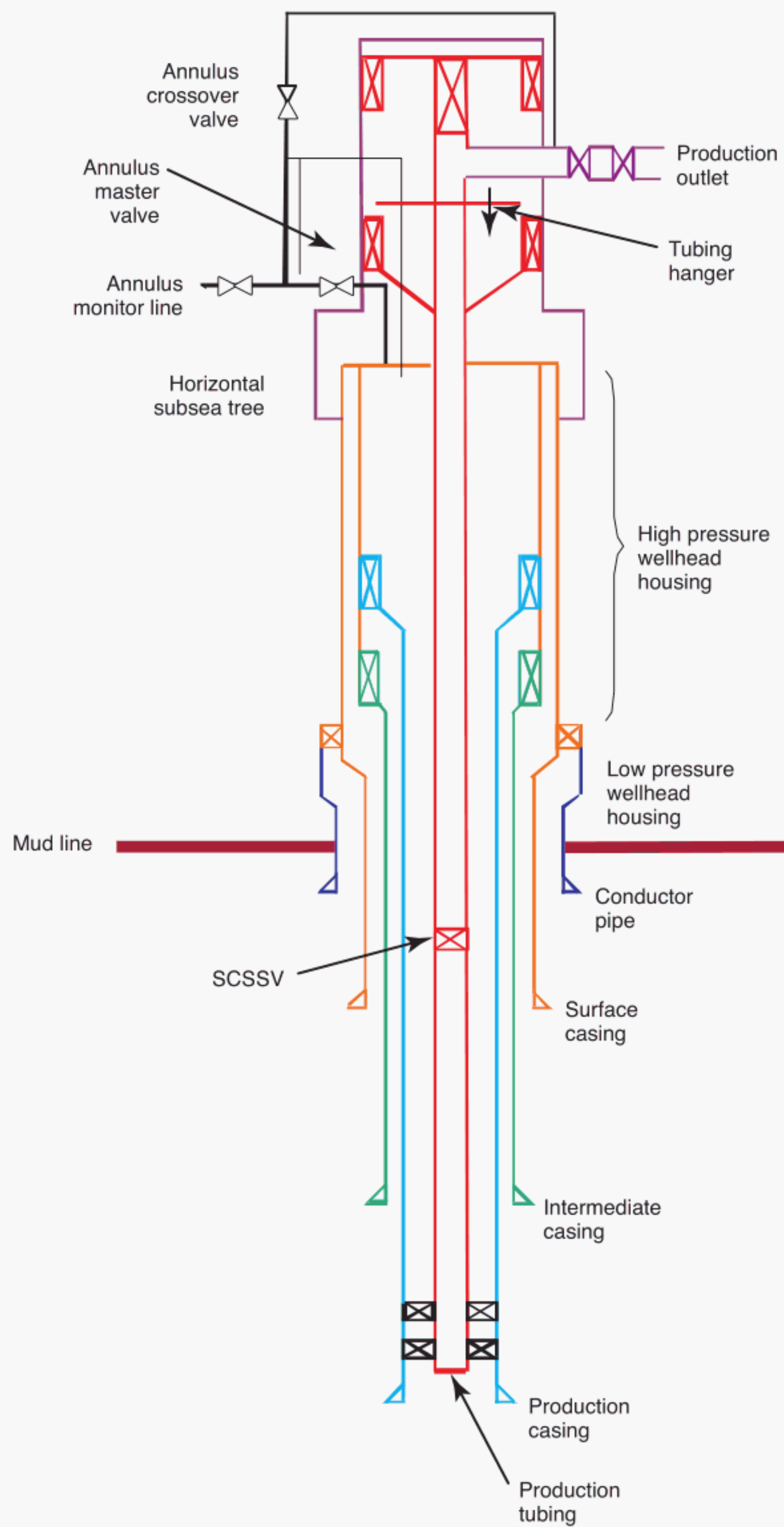
13.2 SUBSEA WELLS

13.2.1 Vertical Subsea Well With “A” Annulus Access And Upstream Crossover Without Tubing Head

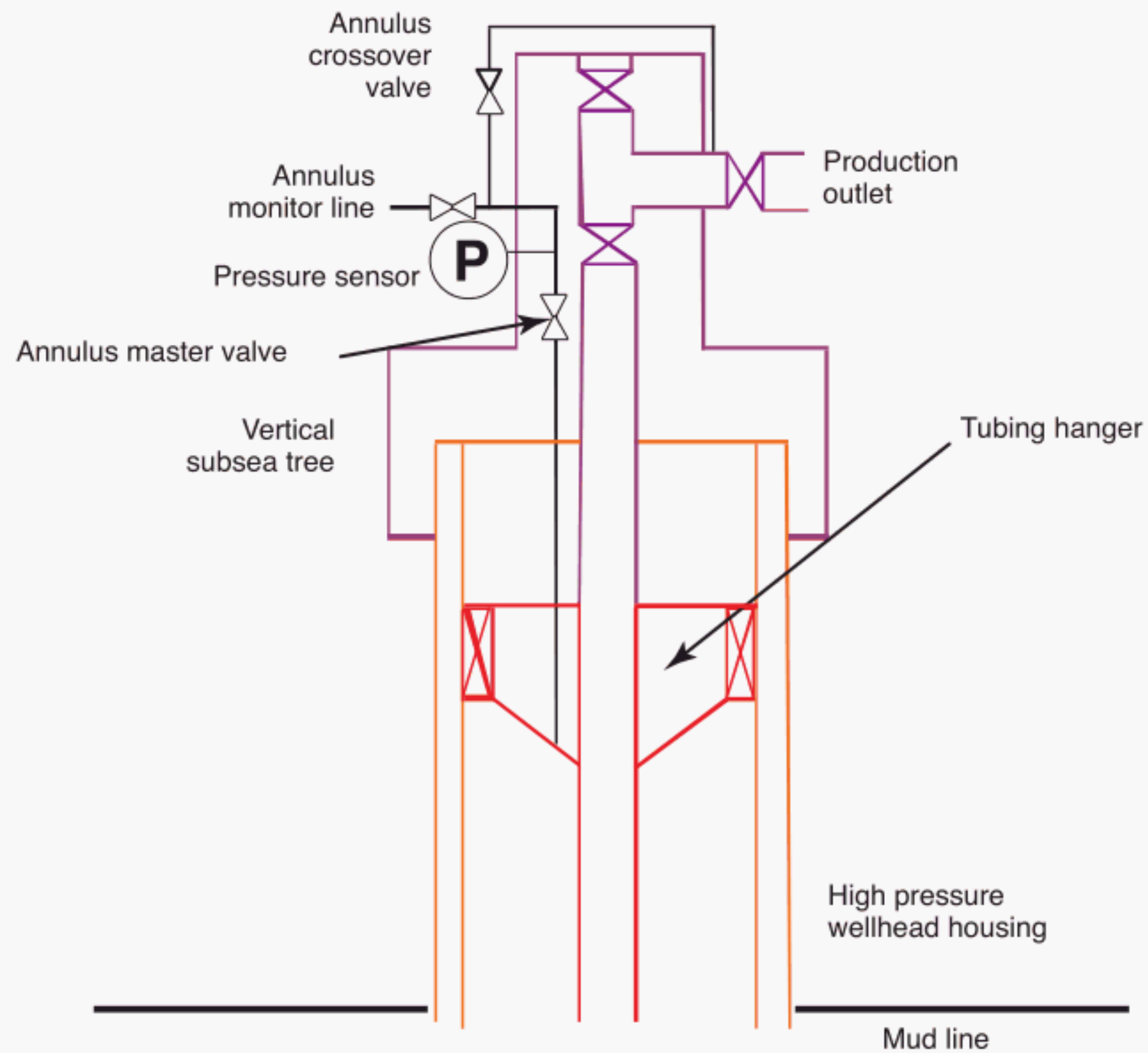


13.2.2 Vertical Subsea Well With A Tubing Head, "A" Annulus Access And Upstream Crossover

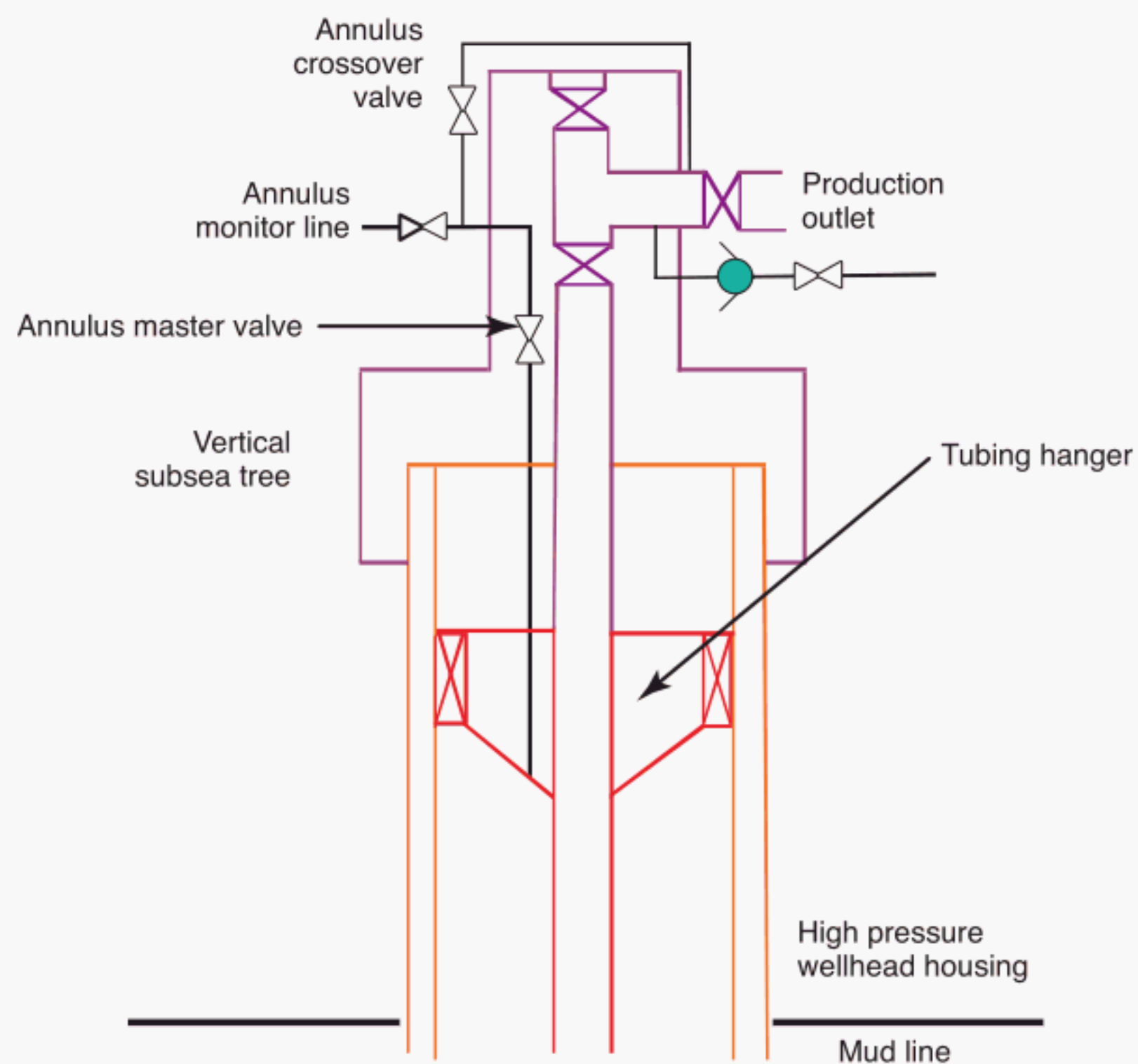
13.2.3 Horizontal Subsea Well With “A” Annulus Access and Upstream Crossover



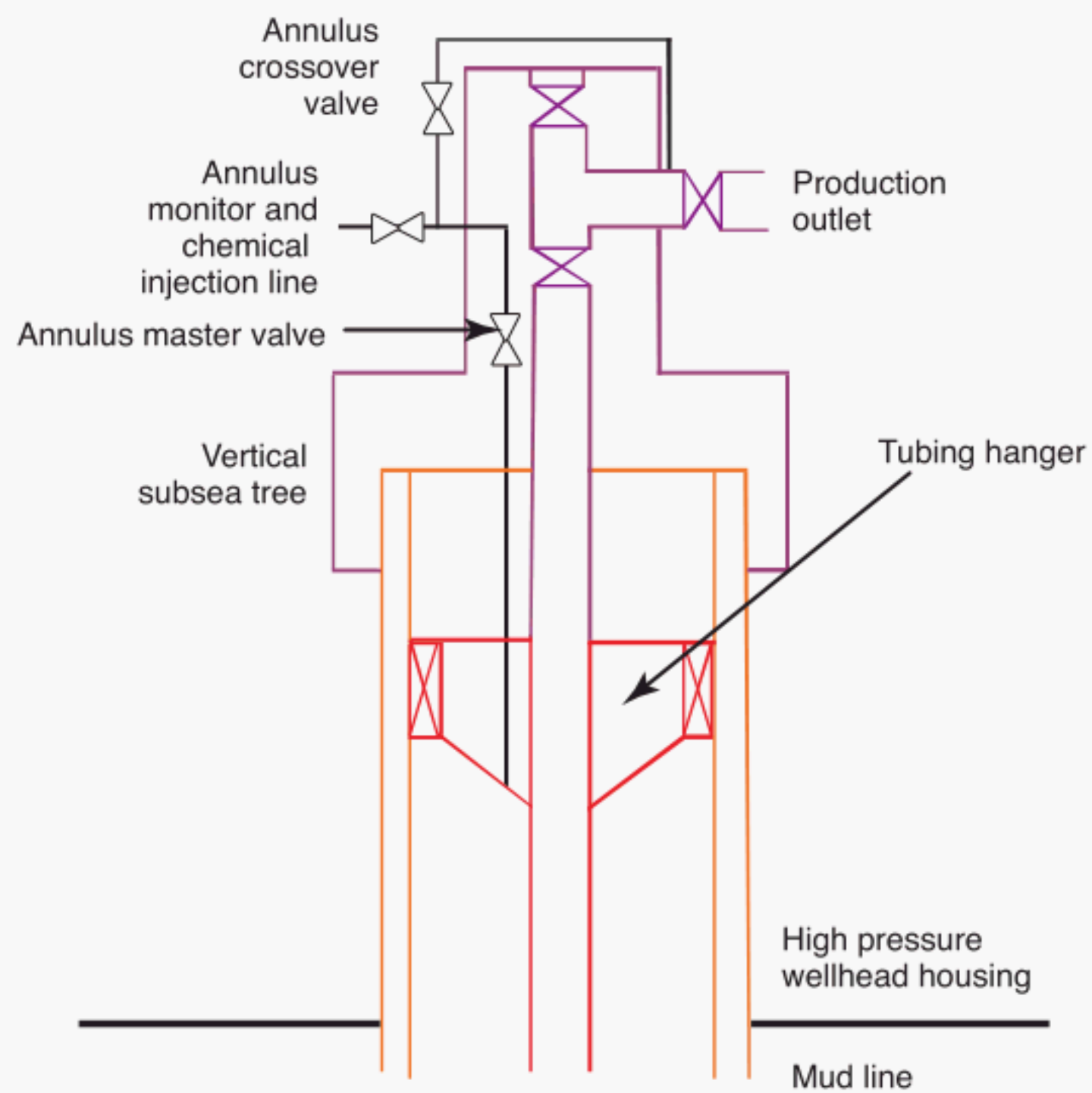
13.2.4 Vertical Subsea Well Using A Pressure Sensor To Monitor “A” Annulus Pressure



13.2.5 Vertical Subsea Well Using Equalized Pressure From a Separate Chemical Injection Line To Measure “A” Annulus Pressure Intermediately with the Well Shut In

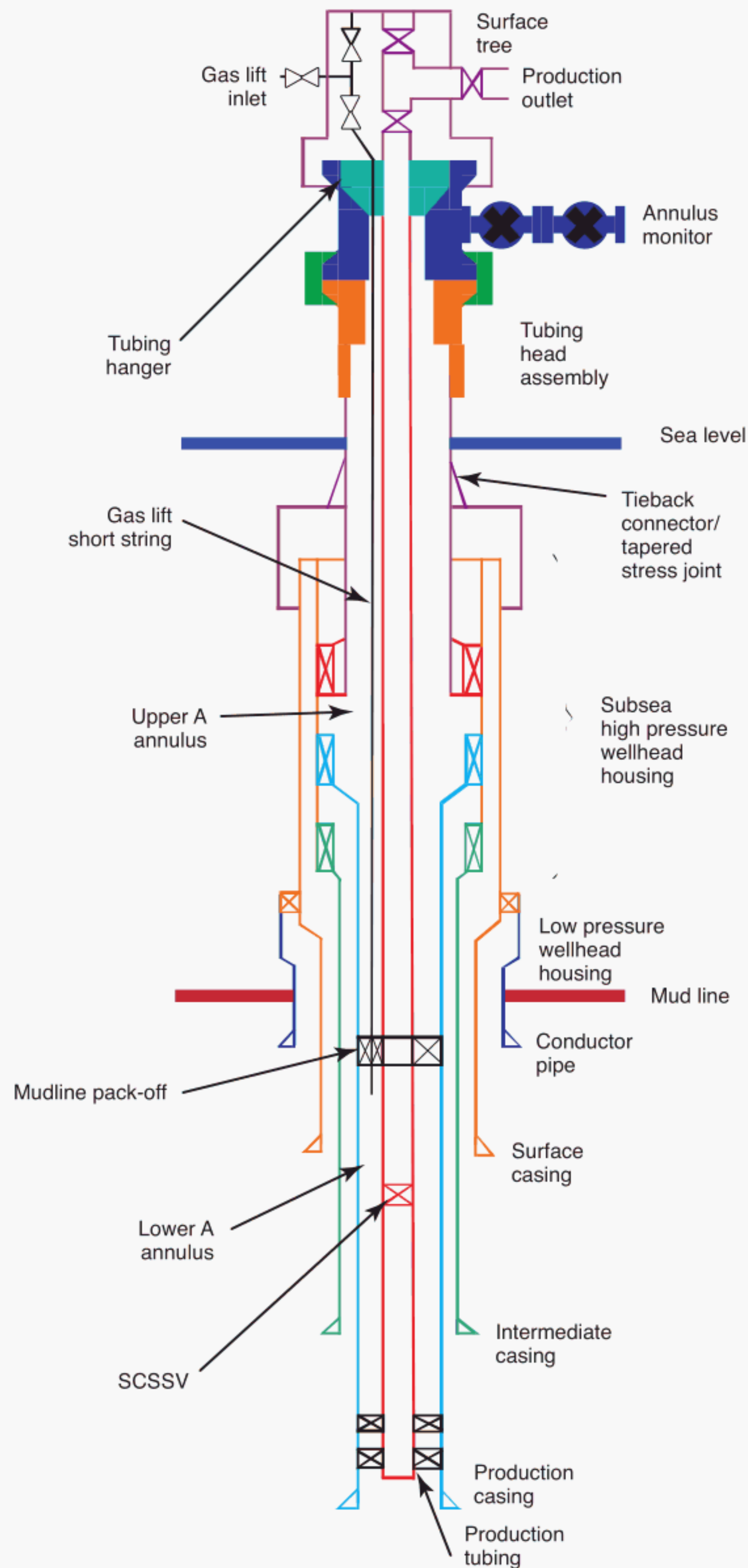


13.2.6 Vertical Subsea Well Using A Combination Annulus Monitor / Chemical Injection Line To Monitor “A” Annulus Pressure

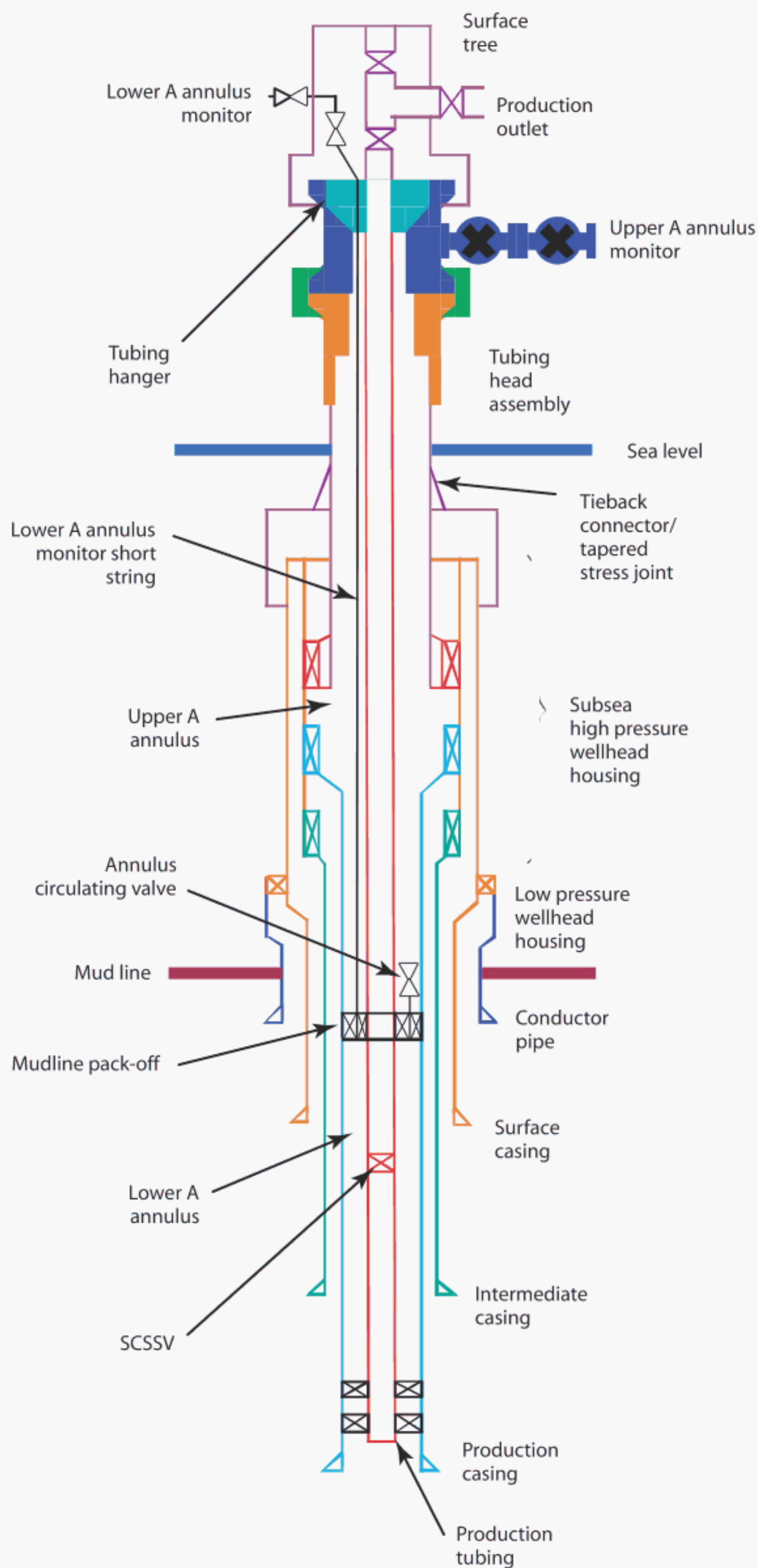


13.3 HYBRID WELLS

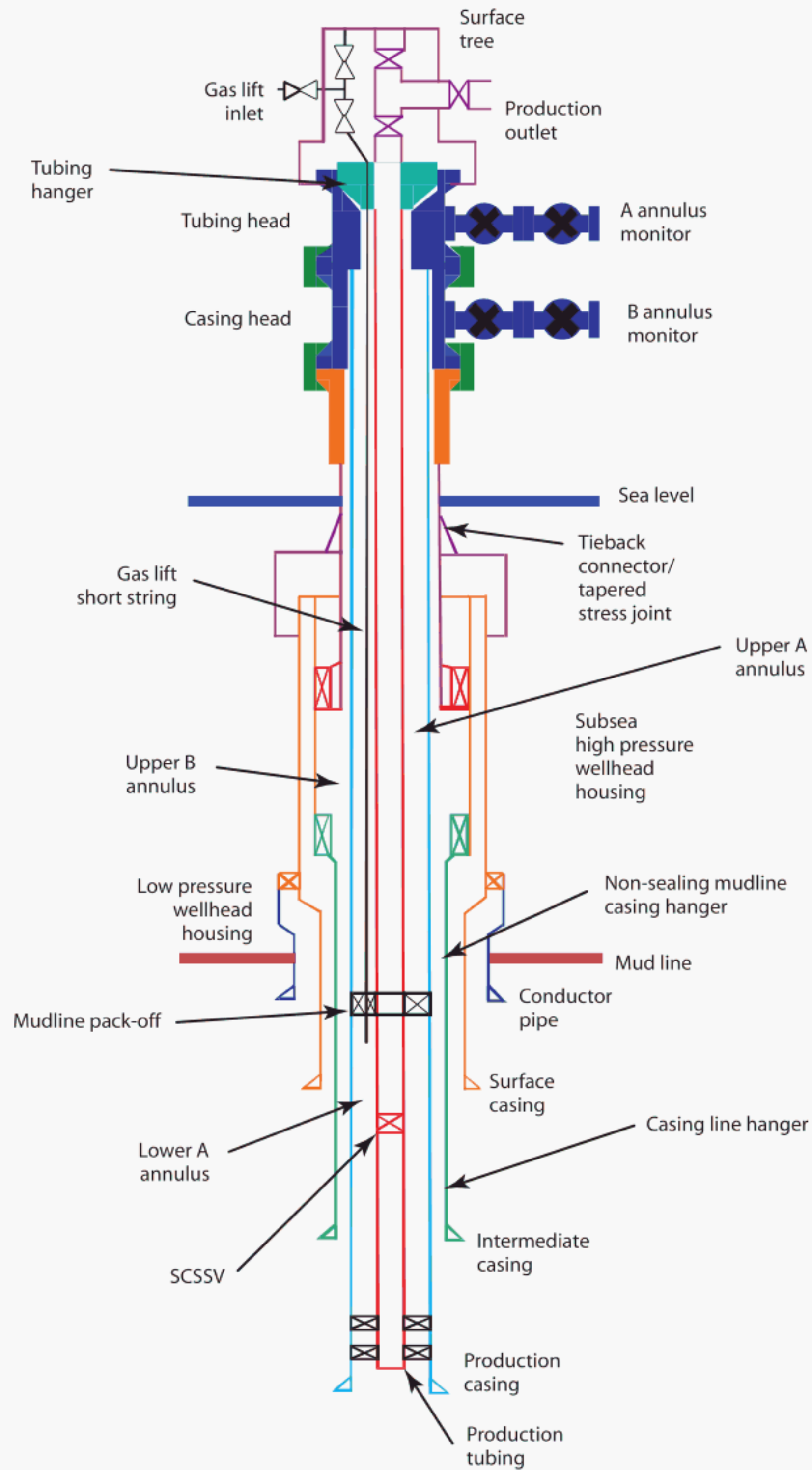
13.3.1 Single Bore Production Riser with Mudline Packoff, with Gas Lift



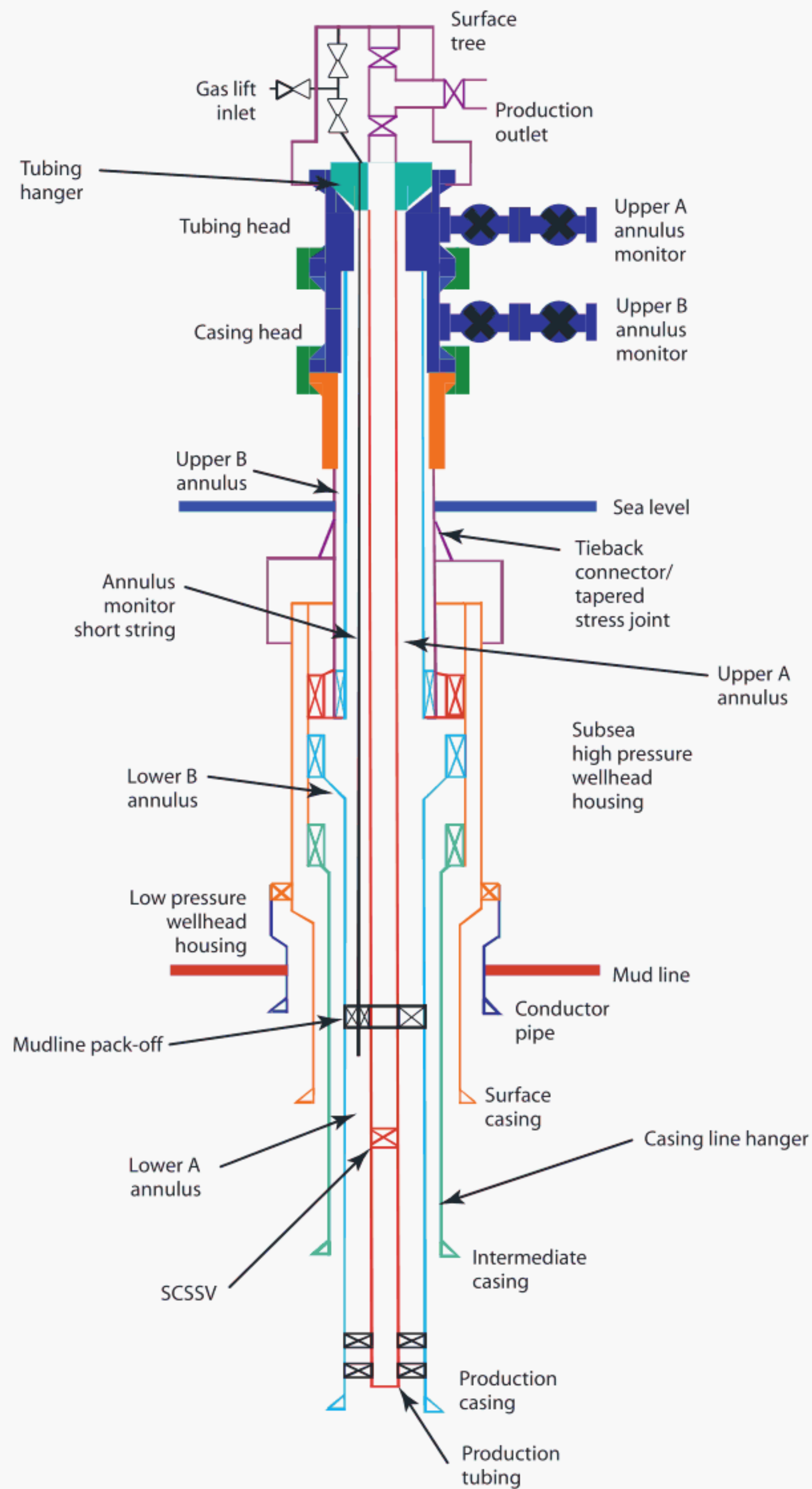
13.3.2 Single Bore Production Riser With Mudline Packoff, Without Gas Lift



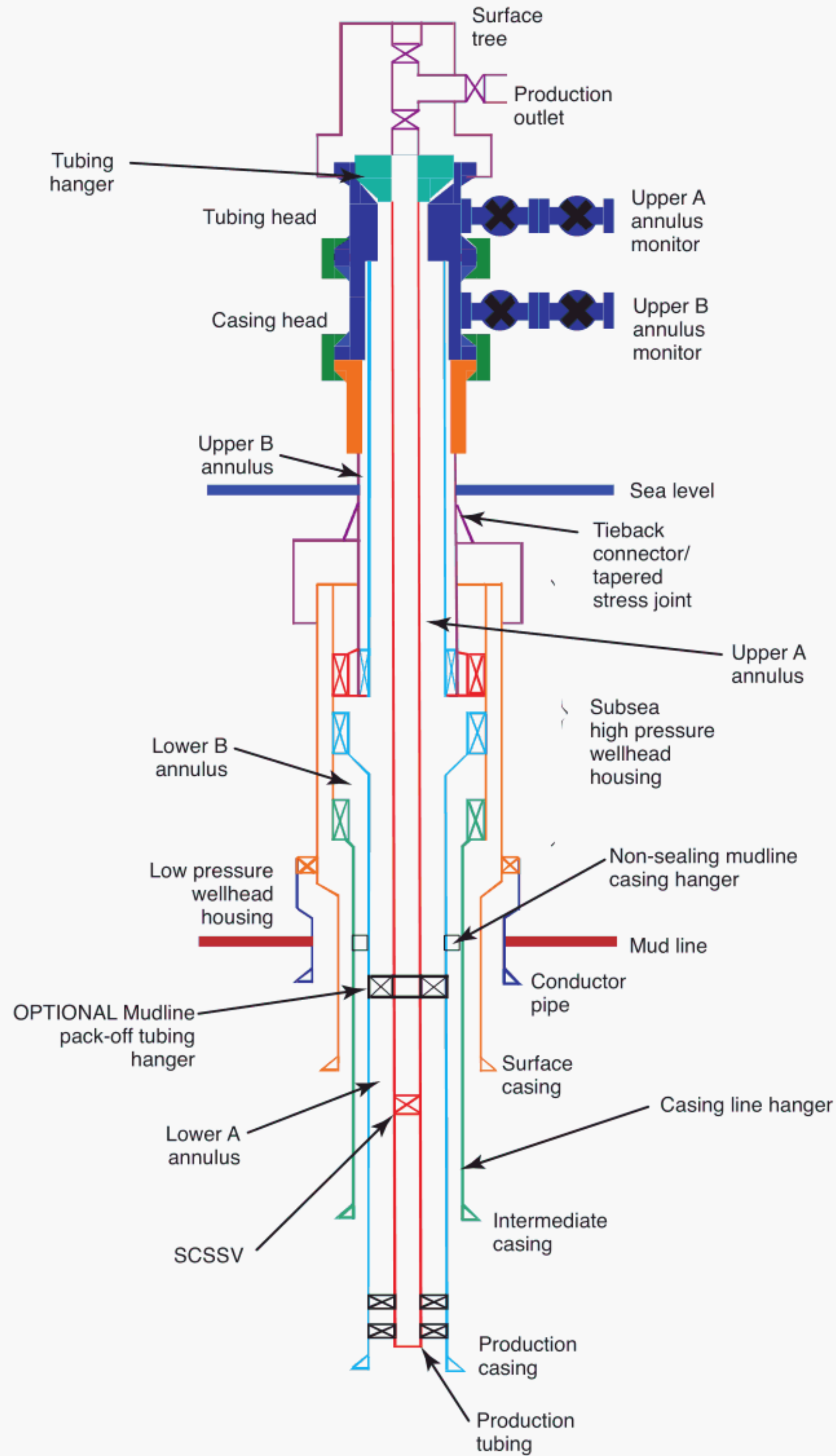
13.3.3 Dual Bore Production Riser With Mudline Packoff, With Gas Lift



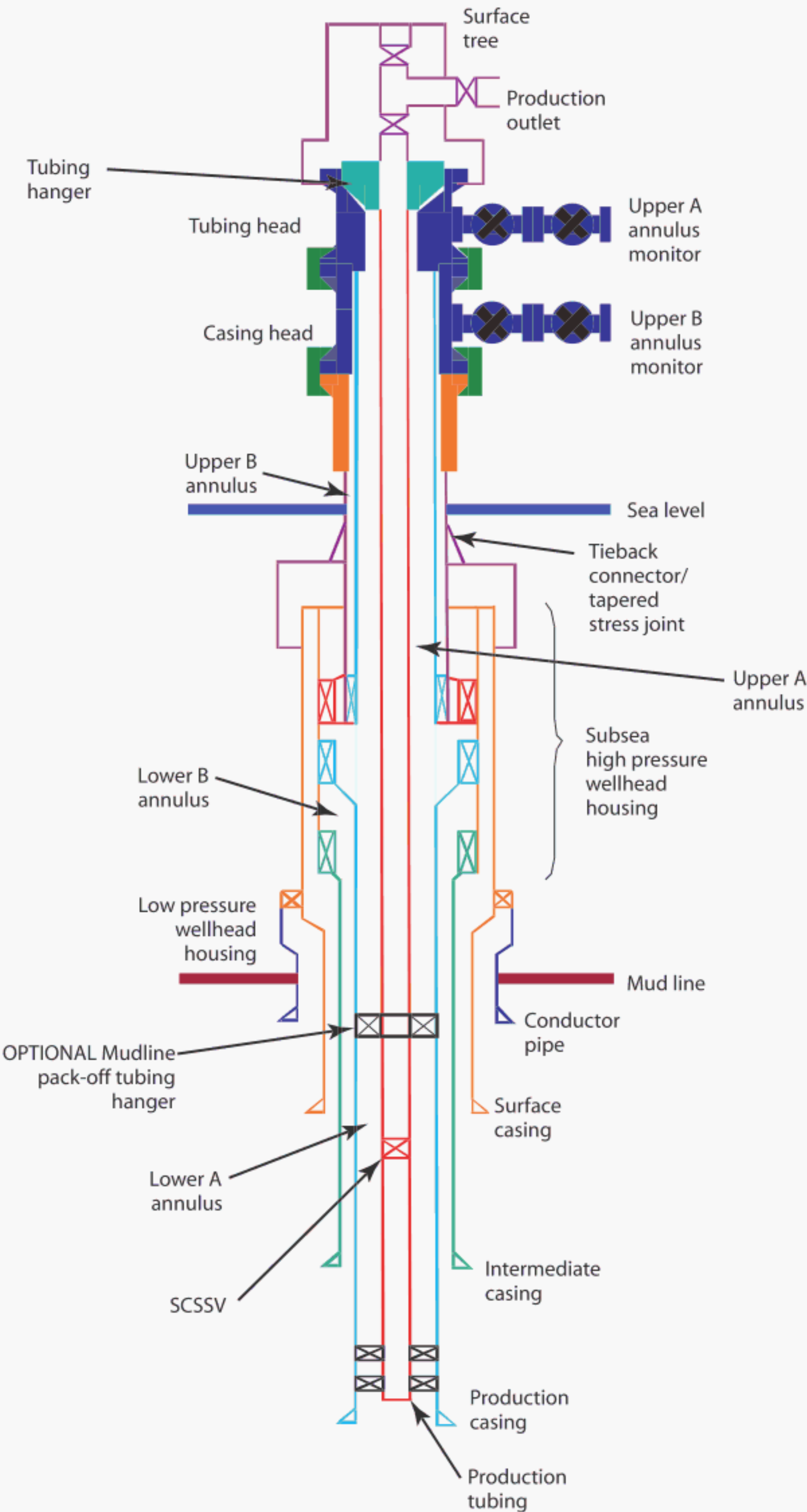
13.3.4 Dual Bore Production Riser Without Production Casing Tieback to the Production Liner, With Gas Lift



13.3.5 Dual Wall Production Riser Without Production Casing Tieback to the Production Liner, Without Gas Lift

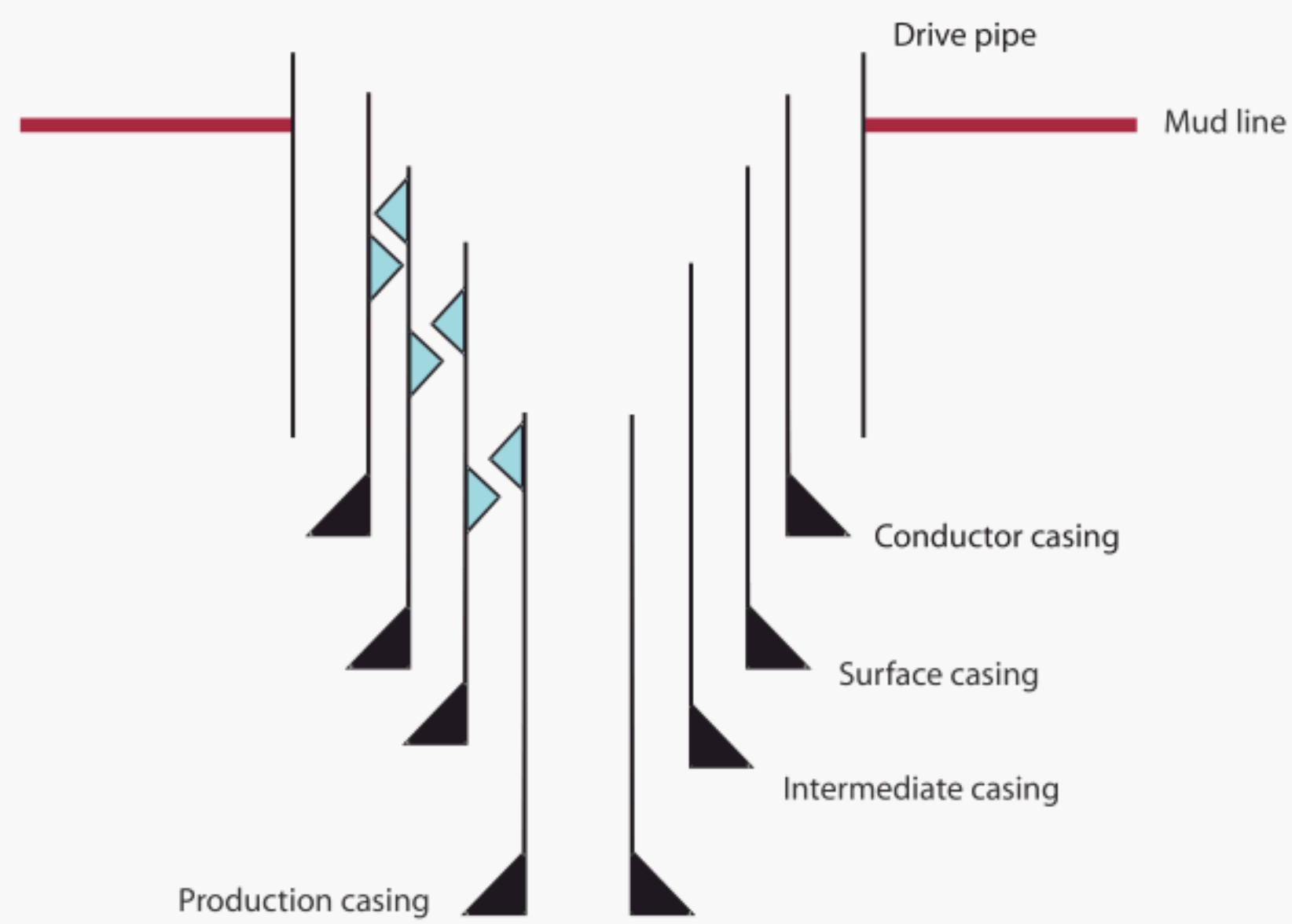


13.3.6 Dual Wall Production Riser Without Casing Tieback, Without Gas Lift

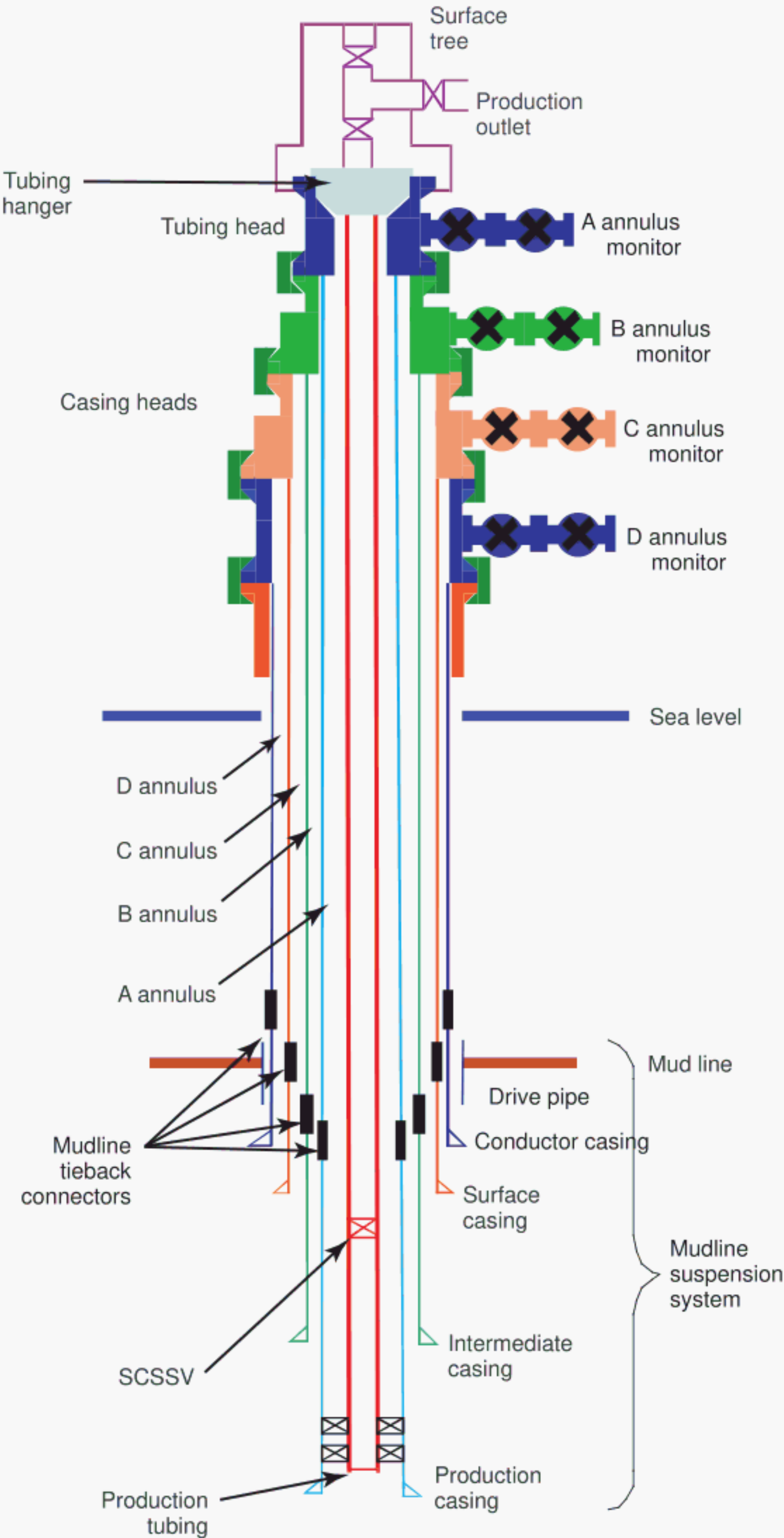


13.4 MUDLINE SUSPENSION WELLS

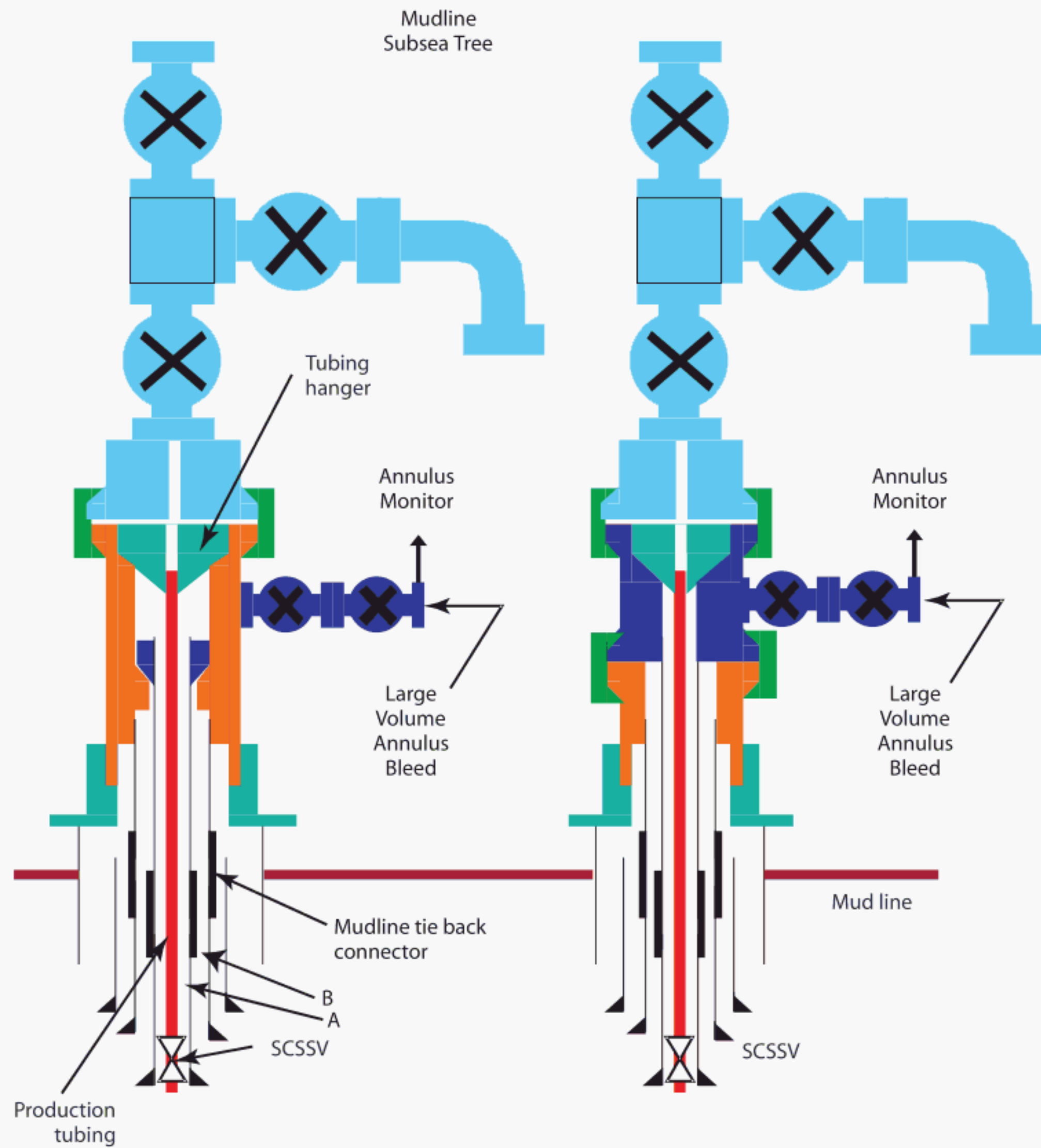
13.4.1 Mudline Suspension System with Production Risers Removed



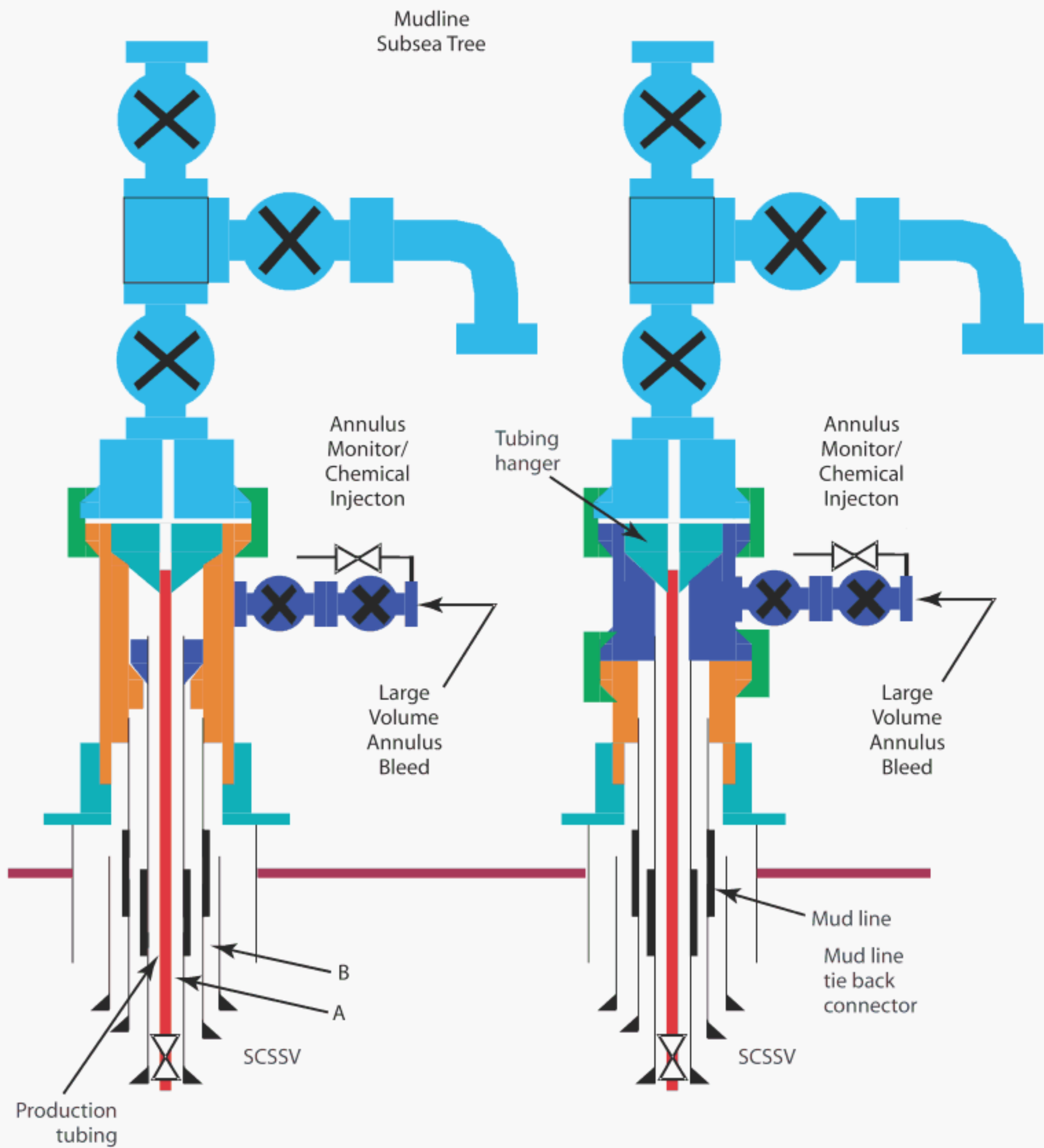
13.4.2 Four String Production Riser Tieback for a Mudline Suspension Well with Surface Tree



13.4.3 Subsea Mudline Tree Installed Illustrating “A” Annulus Monitor Ports



13.4.4 Subsea Mudline Tree Installed Illustrating Combined Chemical Injection / “A” Annulus Monitor Line Ports



14 Appendix D—Pressure Containment and Leak Path Considerations In Well Design

14.1 CASING AND CEMENT

As the drilling of an oil and gas well progresses, the walls of the hole are lined with steel pipe called casing which is normally cemented in place. The casing and cementing program is designed to provide the following benefits:

- Prevent wellbore instability from collapsing the hole.
- Provide a pressure barrier between formation pore pressure, formation fracture pressure, and drilling fluid hydrostatic pressure.
- Protect freshwater aquifers from contamination.
- Isolate water zones from the producing formation.
- Prevent communication between separate hydrocarbon-bearing zones and/or non-hydrocarbon bearing zones.
- Prevent the release of fluids through the wellbore into the environment.
- Provide a structural foundation for the well.
- Facilitate a pressure barrier for the casing strings above and outside which are not designed to handle the formation pressures being encountered.
- Facilitate installation of any required subsurface equipment.
- Provide a conduit to run production tubing and allow for the production of hydrocarbons.

API RP 65, Parts 1, 2 and 3 provide additional information on both mechanical and cement annular barriers for zone isolation including drilling and cementing operations best practices to help prevent or remediate SCP and thermally induced casing pressure.

Note: RP 65 Parts 2 and 3 are currently under development.

14.1.1 Casing Design

The total length of casing which is run in the well during a single operation is called a casing string. (Casing installed in wells on the US OCS must be manufactured in accordance with API Specification 5CT/ISO 11960 *Specification for Casing and Tubing* and API Bulletin 5C3/ISO 10400 *Bulletin on Formulas and Calculations for Casing, Tubing, Drill Pipe and Line Pipe Properties*). There are several principal types of casing strings, the classification being based on the primary function of the string. The drive pipe (and/or conductor pipe) supports unconsolidated deposits and provides hole stability for initial drilling operations. The surface string protects the shallow water sands or weaker formations and usually houses the wellhead. The intermediate or protection string has as its primary objectives the prevention of the surrounding formation from caving in or fracturing outward, and pressure integrity; thus, it facilitates drilling. The production casing (or liner) string is the section through which the well is drilled and completed to depth, produced and controlled. It subsequently protects the rest of the well from produced wellbore fluid pressures. Each string of casing in a well has at its upper end a wellhead, and cement near the bottom to isolate the formations (and previous casing strings) behind it. A completed well may contain several intermediate strings in addition to the surface string and the production string depending on the various formation zones encountered along the way to the well's final depth. In addition, wells may contain drilling or production liners. These are typically suspended at a depth deeper than the mudline. For the purpose of this Recommended Practice, a drilling or production liner is considered a part of the string into which it is installed.

Casing is classified by several primary properties as follows:

- outside and inside diameter;
- wall thickness;
- material grade (N-80, P-110, etc.);
- type of connection (mechanical, threaded, welded);
- length range.

The outside diameter and the wall thickness determine a sixth property, the unit weight. Casing is most frequently classified by its nominal weight, in which the weight is adjusted from the true unit weight to compensate for modified ends for the type of connection utilized. For purposes of this Recommended Practice, a section of a casing string is defined as a continuous length of casing.

A casing string consisting of more than one type of casing is called a combination casing string. A casing string that includes a separate smaller casing string suspended from the base of the previous string (liners) will also be classified as combination casing strings.

When casing is set in a hole, it is subjected to several significant forces. These forces result from external pressure, internal pressure, longitudinal or axial loading and bending. External pressure generates a collapse stress while internal pressure generates a burst stress. Axial loading can generate a tension or compression stress. Axial tension lowers the collapse resistance of the casing while excessive axial loading can result in parted casing. A primary goal of casing design is to select the most economical weights and grades of casing which will withstand the drilling and producing loads.

Well casing design includes the following considerations:

- Required depth to meet the functional requirements.
- Collapse pressure from external fluids.
- Internal pressure from produced or injected fluids.
- Production thermal effects.
- Tension and compression loads from pipe mass, pressure and thermal expansion and contraction.
- Connection integrity (leak proof).
- Utilization of appropriate safety factors.
- Casing wear if the string is to be subjected to rotating drill pipe.
- Stress caused by bending in a directional well.
- Potential exposure to Hydrogen Sulfide or Carbon Dioxide.

14.1.2 Production Casing

The production casing is designed to withstand at least the maximum pressure of the formations encountered. It should also be designed to withstand the equivalent load of an early life surface tubing leak, i.e. shut-in pressure at the surface over a full column of packer fluid. It should also be designed to withstand annular pressure due to the thermal effects of production. The production string is normally considered to be a component of the primary well barrier system and the production casing is normally considered a component of the secondary well barrier system. Since both the production casing and production string are designed to withstand the maximum surface pressures plus an additional safety factor, they serve as redundant pressure barriers. In the event that either the production string or the production casing fails, a redundant barrier system may no longer exist since the outer casing strings are typically designed for drilling loads only and not for production loads. For this reason, SCP on the “A” annulus is a concern since the desired redundant barrier system may have been compromised.

The source of SCP on the “A” annulus is often the producing formation due to leaks in the production string, packers, seals, etc. In other cases, the source may be a zone other than the producing zone and SCP occurs on the “A” due to a production casing leak.

Common causes of pressure in the “A” annulus due to production casing leaks include:

- production casing connection problems (design, make-up, inadequate sealing of connections, etc.);
- erosion/corrosion;
- stress cracking (sulfide or chlorine);
- wear from drilling or workover operations;
- mechanical rupture or parting;
- damage due to subsidence or fault movement.

14.1.3 Outer Casings

The outer casing strings, i.e., surface and intermediate (protective), are designed for the drilling of the well and are typically designed to withstand the maximum surface pressure while drilling. They are typically not designed to withstand the maximum pressure of the deepest producing formation. The top of cement in the “B” and “C” annuli should be set above the highest hydro-

carbon zone or the highest zone to be isolated. SCP on outer strings may be sourced to zones other than the primary producing zone. SCP on these strings may be related to channels or fractures through the cement allowing the migration of gas from porous zones or may be from porous formations not covered by cement.

14.1.4 Cementing Program

The cement column in each annulus may extend to the surface or to some lesser height. If cement does not completely displace the annulus, a drilling fluid column will exist above the cement, depending on the annulus being cemented, the presence or absence of hydrocarbon bearing zones and potential hazards.

Common cement problems that can contribute to SCP may include:

- Damage to cement from operational activities such as squeezing or fracturing.
- Thermal cycling.
- Micro-annulus channeling.
- Cracking/micro fractures due to stress loading conditions.
- Poor cement bonding to the casing and/or formation.
- Channeling due to poor mud displacement may result in a pressure conduit between different depths of the well.
- Lost circulation during cementing that prevents cement isolation or inadequate cement volume pumped.
- Gas channeling through the cement.
- Lack of casing centralization and hole/casing annular clearances.

14.1.5 Production (Completion) String Design

The production (completion) string is normally designed to be the primary well barrier system for containing and controlling produced (or injected) wellbore fluids entering the well. The production string should be designed to withstand similar stresses to which the production casing is subjected, plus resist the corrosive effects of the produced fluids and the dynamic loads in the hybrid well production riser. The production string may also contain additional components such as sliding sleeves, gas lift mandrels and valves, chemical injection mandrels and ports, various monitoring line connections, SCSSV, etc. Because of the high number of connections in offshore production strings, leaks are a major reason for pressure in the “A” annulus.

Common production string leaks and causes may include:

- tubing connection leaks;
- tubing integrity problems;
- erosion/corrosion;
- fatigue;
- stress cracking;
- gas lift mandrels and valves;
- chemical injection mandrels;
- SCSSV injection line and connections.

14.1.6 Production Packers, Packoffs and Seal Assemblies

Packers, packoffs or other sealing mechanisms are utilized to isolate portions of the wellbore. Packers refer to the sealing mechanism between the production tubing and the production casing, immediately above the perforations leading to the producing well formation. Packoffs refer to the sealing mechanism at the top of a casing string between two casing strings. The wellhead tubing hanger provides mechanical support for the production tubing suspended in the wellhead and seals between the tubing and the production casing/wellhead body. The tubing hanger may provide additional pressure controlled penetrations for other subsurface equipment functions. Both metal-to-metal seals and elastomer seals can be used as seal assemblies.

Potential causes of SCP from this equipment may include:

- Casing string connection leak at the casing hanger.
- Casing hanger seal degradation.
- Tubing hanger connection to the tubing (above or below) leaks into the “A” annulus.
- Tubing hanger annular seal degradation.
- Internal or external packer seal.
- Failures in other penetrations through the tubing hanger to support subsurface equipment, such as:
 - leakage around electrical line penetrations;
 - pressure or leakage from chemical injection lines;
 - pressure or leakage from hydraulic control lines used to operate SCSSV or other remote subsurface devices.

Common causes of packer, packoff and seal assembly leaks may include:

- damaged sealing surface;
- thermal cycling and/or high temperatures and low temperatures;
- improper installation;
- corrosion;
- incompatibility between the seal and packer fluids;
- cyclic loading;
- excessive tubing injection pressure.

14.1.7 Wellheads, Christmas Trees and Subsea Trees

The wellhead and tree must have a pressure rating greater than the maximum shut-in tubing pressure for the well. The wellhead and/or tree may be either located on the surface, subsea, or both (hybrid). Leaks within the sealing mechanisms within the wellhead and tree may occur.

Common leak paths may include:

- Cross communication between casing strings due to casing hanger connection or packoff seal degradation.
- Cross communication into the annulus due to tubing hanger seal, penetration or other penetration seal degradation.
- Cross communication between several leaking valves from the production flow path back into the annulus.
- Communication between the gas lift system and the production annulus due to a leaking casing valve.

14.1.8 Tools for Identifying Leak Paths

There are several diagnostic methods that may be used to attempt to identify the leak path and/or source in wells with SCP. These include:

- Analysis of bleed off/build up tests and comparison to previous diagnostic tests.
- Analysis of recovered fluids from a bleed off test and comparison to known formation gases/fluids.
- Production well logs and surveys.
 - noise, temperature and/or oxygen activation logs to show flow;
 - cement evaluation logs to map potential flow paths;
 - decay time logs to display gas accumulations;
 - downhole video cameras.
- Measuring fluid levels in the annulus with acoustic tests.
- Wellhead seal inspections.



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