

Deepwater Well Design and Construction

API RECOMMENDED PRACTICE 96
FIRST EDITION, MARCH 2013



AMERICAN PETROLEUM INSTITUTE

Special Notes

API publications necessarily address problems of a general nature. With respect to particular circumstances, local, state, and federal laws and regulations should be reviewed.

Neither API nor any of API's employees, subcontractors, consultants, committees, or other assignees make any warranty or representation, either express or implied, with respect to the accuracy, completeness, or usefulness of the information contained herein, or assume any liability or responsibility for any use, or the results of such use, of any information or process disclosed in this publication. Neither API nor any of API's employees, subcontractors, consultants, or other assignees represent that use of this publication would not infringe upon privately owned rights.

API publications may be used by anyone desiring to do so. Every effort has been made by the Institute to assure the accuracy and reliability of the data contained in them; however, the Institute makes no representation, warranty, or guarantee in connection with this publication and hereby expressly disclaims any liability or responsibility for loss or damage resulting from its use or for the violation of any authorities having jurisdiction with which this publication may conflict.

API publications are published to facilitate the broad availability of proven, sound engineering and operating practices. These publications are not intended to obviate the need for applying sound engineering judgment regarding when and where these publications should be utilized. The formulation and publication of API publications is not intended in any way to inhibit anyone from using any other practices.

Any manufacturer marking equipment or materials in conformance with the marking requirements of an API standard is solely responsible for complying with all the applicable requirements of that standard. API does not represent, warrant, or guarantee that such products do in fact conform to the applicable API standard.

Users of this Recommended Practice should not rely exclusively on the information contained in this document. Sound business, scientific, engineering, and safety judgment should be used in employing the information contained herein.

All rights reserved. No part of this work may be reproduced, translated, stored in a retrieval system, or transmitted by any means, electronic, mechanical, photocopying, recording, or otherwise, without prior written permission from the publisher. Contact the Publisher, API Publishing Services, 1220 L Street, NW, Washington, DC 20005.

Copyright © 2013 American Petroleum Institute

Foreword

Life cycle well integrity is an important objective in the design and execution of a deepwater (DW) well program. Technical, operational, and organizational solutions are to be employed such that the risk of an unintended release of formation fluids is minimized during drilling, completion, operational, and abandonment phases of the well. This document describes established well design practices and operational procedures that engineers, well planners, and operators consider when planning and executing a DW well project. It is not intended to prohibit the development and application of new technology.

The verbal forms used to express the provisions in this recommended practice are as follows:

- the term “shall” denotes a minimum requirement in order to conform to the recommended practice;
- the term “should” denotes a recommendation or that which is advised but not required in order to conform to the recommended practice;
- the term “may” is used to express permission or a provision that is optional;
- the term “can” is used to express possibility or capability.

Nothing contained in any API publication is to be construed as granting any right, by implication or otherwise, for the manufacture, sale, or use of any method, apparatus, or product covered by letters patent. Neither should anything contained in the publication be construed as insuring anyone against liability for infringement of letters patent.

This document was produced under API standardization procedures that ensure appropriate notification and participation in the developmental process and is designated as an API standard. Questions concerning the interpretation of the content of this publication or comments and questions concerning the procedures under which this publication was developed should be directed in writing to the Director of Standards, American Petroleum Institute, 1220 L Street, NW, Washington, DC 20005. Requests for permission to reproduce or translate all or any part of the material published herein should also be addressed to the director.

Generally, API standards are reviewed and revised, reaffirmed, or withdrawn at least every five years. A one-time extension of up to two years may be added to this review cycle. Status of the publication can be ascertained from the API Standards Department, telephone (202) 682-8000. A catalog of API publications and materials is published annually by API, 1220 L Street, NW, Washington, DC 20005.

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

Contents

	Page
1 Scope	1
2 Normative References	2
3 Terms, Definitions, and Abbreviations	2
3.1 Terms and Definitions	2
3.2 Abbreviations	10
4 Deepwater Rig Systems and Subsea Configurations	11
4.1 General	11
4.2 Rig Options	12
4.3 Stationkeeping System	12
4.4 Marine Drilling Riser System	14
4.5 BOP System	14
4.6 BOP Control System	16
4.7 Emergency Functions	18
4.8 Subsea Wellhead and Production Tree Configurations	20
4.9 Remotely Operated Vehicle Systems	20
5 Well Design Considerations	21
5.1 General	21
5.2 Deepwater Well Architecture	21
5.3 Barrier Philosophy	29
5.4 Load Cases Drilling and Completion Conditions	37
5.5 Tubing Design	41
6 Special Considerations for Drilling	43
6.1 Wellheads	43
6.2 Casing Hanger/Seal Assembly Lockdown to Subsea Wellhead Systems	46
6.3 Structural Casing	49
6.4 Riserless Mudline Hangers and Submudline Hangers	50
6.5 Cemented Shoe Track System	51
6.6 Subsidence/Compaction	52
6.7 Salt Loading	52
6.8 Pore Pressure Prediction	54
6.9 Shallow Hazards Considerations	56
6.10 Gas Hydrate Formation	58
6.11 Liner Hangers	58
6.12 Expandable Tubular Goods	60
6.13 Alloys in a Cracking or Corrosive Environment	61
6.14 Downhole Threaded Connections	61
6.15 Casing Landing Strings	62
6.16 Tension Leg Platforms/Spar Considerations	63
6.17 Annular Pressure Build-up Considerations	64
6.18 Annular Abandonment Considerations	67

Contents

	Page
7 Special Considerations for Completions	67
7.1 Completion Fluids	67
7.2 Materials	68
7.3 Tubing/Work String Connections	69
7.4 Flow Assurance	70
7.5 Wellbore Considerations	71
7.6 Deepwater Sandface Completion Techniques	73
7.7 Intelligent Wells	74
7.8 Fishability of Tubing and Work String Components	74
7.9 Injector Well Considerations	75
8 Drilling Operations Considerations	75
8.1 Riserless Operations	75
8.2 Operations with Subsea BOP and Riser Installed	76
9 Completion Operations Considerations	86
9.1 Completion Operation Phases	86
9.2 Well Testing and Unloading Considerations	90
9.3 Preproduction Start-up Review	96
10 Management of Change	97
10.1 Unexpected Events	97
10.2 Well Contingency Plans	98
10.3 Stakeholder Interface	98
10.4 Stop Work Authority	98
Annex A (informative) Examples of Barriers Employed During Operations	100
Annex B (informative) Example Barrier Definitions	124
Annex C (informative) Examples of Inflow Testing	149
Bibliography	156
Figures	
1 Marine Drilling Riser System Example	15
2 BOP Controls	18
3 Well Architecture Examples	23
4 Normal-clearance Deepwater Casing Schematic with 30-in. Structural Casing	24
5 Tight-clearance/Long-string Intermediate Casing Schematic with 36-in. Structural Casing	25
6 Representation of Barrier Verification Categories	33
7 Example of Hydrate Stability Envelope	57
8 Subsea Tree with Tubing Head and “A,” “B,” and “C” Annuli	66
9 Subsea Test Tree	93
10 Surface Flow Head	94
11 Coil Tubing and Lift Frame	95
A.1 Drilling Ahead	101
A.2 Emergency Evacuation/Disconnect/LMRP Repair	106
A.3 Abandonment After Drilling out the Shoe Track (Full BOP Removal)	110

Contents

	Page
A.4 Abandonment without Drilling the Shoe track (Full BOP Removal)	111
A.5 Tripping After Tubing-conveyed Perforating	115
A.6 Flowback Through Production Tubing to Rig	120

Tables

1 Typical Rig and System Options	12
2 Typical Casing Types and Description	27
3 Example Basis of MASP Internal Load Cases	39
4 Tubing/Workstring Design Requirements	43
5 Completion Tubing String Loads	44
6 Completion Work String Loads	45
7 Salt Properties	53
8 Unloading the Well to the Rig during Completions	91
A.1 Drilling Ahead	102
A.2 Emergency Evacuation/Disconnect/LMRP Repair	107
A.3 Abandonment (Full BOP Removal)	112
A.4 Tripping After Tubing-conveyed Perforating	116
A.5 Flowback Through Production Tubing to Rig	121
B.1 Hydrostatic Fluid	125
B.2 Casing	127
B.3 Cement Behind Casing or Liner	129
B.4 Cemented Shoe Track	132
B.5 Cement Plugs	135
B.6 Subsea Wellhead	137
B.7 Subsea Blowout Prevention Equipment	138
B.8 Subsea Production Tree	140
B.9 Production Tubing String	141
B.10 Production Packer	143
B.11 Surface-Controlled Subsurface Safety Valve (SCSSV)	144
B.12 Vertical Tree Tubing Hanger Plug	146
B.13 Horizontal Tree Crown Plugs	147

Introduction

The safe construction and operation of a deepwater (DW) well requires proper well design and operational procedures. The complexity of DW operations demands an in-depth understanding of the DW environment (e.g., metocean, marine, and subsurface) as well as DW procedures and equipment. This combined understanding is used to provide the basis of design for DW subsea wells.

This recommended practice provides well design and operational considerations to assist an experienced well (drilling or completion) engineer to safely design and construct any DW well drilled with subsea blowout preventers (BOPs). This document also addresses riserless drilling considerations prior to the installation of the subsea BOPs.

Deepwater Well Design and Construction

1 Scope

The complexity of deepwater (DW) operations requires a thorough understanding of well design criteria and associated equipment. This recommended practice (RP) provides engineers a reference for DW well design as well as drilling and completion operations. This RP will also be useful to support internal reviews, internal approvals, contractor engagements, and regulatory approvals.

The scope of this RP is to discuss DW drilling and completion activities performed on wells that are constructed using subsea blowout preventers (BOPs) with a subsea wellhead. This document addresses the following.

- Identifies the appropriate barrier and load case considerations to maintain well control during DW well operations (drilling, suspension, completion, production, and abandonment).
- Supplements barrier documentation in API 65-2 with a more detailed description of barriers and discussion of the philosophy, number, type, testing, and management required to maintain well control. This document also supplements the barrier documentation in API 90 in regard to annular pressure buildup (APB). Abandonment barrier requirements are described for use when designing the well.
- Discusses load assumptions, resistance assumptions, and methodologies commonly used to achieve well designs with high reliability. The load case discussion includes less obvious events that can arise when unexpected circumstances are combined.
- Describes the risk assessment and mitigation practices commonly implemented during DW casing and equipment installation operations.

The purpose of this document is to enhance safety and minimize the likelihood of loss of well control or damage to the environment. These practices are generally intended to apply to subsea wells drilled with subsea BOPs in any water depth. Some of the descriptions of rig hardware and operations, such as remotely operated vehicles (ROVs), are less relevant in shallower water depths [e.g. less than 500 ft (152 m)]. In these shallower water depths the operator may substitute alternative hardware or operations that maintain safety and system reliability.

The following aspects of DW well design and construction are outside the scope of this document.

- Detailed casing design load case definitions (does not include specific casing designs or design factors). Individual companies combine differing severities of loads and resistances or differing calculation methods to achieve designs with similar high levels of reliability.
- Wells drilled and/or completed with a surface BOP and high pressure riser from a floating production system; however, considerations for wells predrilled with floating rigs to be completed to a floating production system are included.
- Well control procedures (refer to API 59 for well control information).
- Managed pressure drilling operations (including dual gradient drilling).
- Production operations and fluids handling downstream of the tree (subsea facilities/subsea architecture, and surface facilities/offloading hydrocarbons).
- Intervention operations.
- Quality assurance (QA) programs.

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document applies (including any addenda/errata).

API Recommended Practice 17H, *Remotely Operated Vehicle (ROV) Interfaces on Subsea Production Systems*

API Recommended Practice 53, *Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells*

3 Terms, Definitions, and Abbreviations

3.1 Terms and Definitions

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

3.1.1

“A” annulus

Annulus between the production tubing and production casing.

3.1.2

accumulator

A pressure vessel charged with inert gas and used to store hydraulic fluid under pressure

3.1.3

annular blowout preventer

Blowout preventer that uses a shaped elastomeric sealing element to seal the space between the tubular and the wellbore or to seal an open hole.

3.1.4

annular pressure buildup

APB

Pressure generated within an annulus by thermal expansion of wellbore fluids, typically during production.

NOTE APB can also occur during drilling operations when trapped annular fluids at cool shallow depths are exposed to high temperatures induced by fluids circulating from deep, hot hole sections. This thermally induced pressure is defined and listed in API 90 as thermal casing pressure.

NOTE 2 Can also occur from migration of formation fluids, as defined in API 90.

3.1.5

annulus

Any space between concentric tubulars or between the tubular and the wellbore (formation).

3.1.6

autoshear system

A safety system that is designed to automatically shut-in the wellbore in the event of a disconnect of the LMRP.

NOTE When the autoshear is engaged, disconnecting the LMRP closes the shear rams.

3.1.7**backup gradient**

Hydrostatic gradient of fluid assumed to be on the other side of the tubular string from the design load case being considered.

NOTE Typically subtracted from the design pressure load profile in order to calculate a “net” pressure.

3.1.8**barrier**

Component or practice that contributes to the total system reliability by preventing formation fluid or gas flow.

3.1.9**barrier plan**

The operator’s specific operating procedure for barrier placement, verification, and removal.

3.1.10**barrier system**

A combination of barriers acting together to prevent unintended fluid and/or gas flow.

NOTE The barrier system includes both physical and operational barriers.

3.1.11**basis of design**

All information and assumptions utilized to design the well.

3.1.12**blind ram**

A closing and sealing component in a ram blowout preventer that seals the open wellbore.

3.1.13**blind shear ram****BSR**

A closing and sealing component in a ram blowout preventer that first shears certain tubulars in the wellbore and then seals the bore, or acts as a blind ram if there is no tubular in the wellbore.

NOTE Other common names for this ram include shearing, blind shear, or blind/shear rams.

3.1.14**blowout preventer****BOP**

Equipment installed on the wellhead or wellhead assemblies to contain wellbore fluids either in the annular space between the casing and the tubulars, or in an open hole during well drilling, completion, and testing operations.

NOTE Blowout preventers are not: gate valves, workover/intervention control packages, subsea shut-in devices, well control components (per API 16ST), intervention control packages, diverters, rotating heads, rotating circulating devices, capping stacks, snubbing or stripping packages, or nonsealing rams.

3.1.15**capping stack****containment stack**

A device that controls, diverts, and shuts in a well flow stream during a well containment operation.

NOTE This equipment is deployed only as required and is not a part of standard rig equipment.

3.1.16**cement barrier**

A cement column designed and placed to prevent formation fluid or gas flow between geologic formations, within annular spaces, or in the wellbore (a subset of physical barriers).

3.1.17**confirmed barrier**

A barrier whose performance has been verified by satisfying placement acceptance criteria through evaluating data collected during installation.

NOTE A confirmed barrier has a lower level of assurance than a tested barrier.

EXAMPLE A barrier that is intended to resist pressure from below during its service is tested successfully after installation with pressure from above. The barrier in this scenario is considered to be a confirmed barrier but does not meet the definition of a tested barrier because it was not tested in the direction of flow in service.

3.1.18**control pod**

An assembly of valves and regulators (either hydraulically or electrically operated) that when activated, will direct hydraulic fluid through special apertures to operate the BOP functions.

3.1.19**deadman system**

A safety system designed to automatically shut in the wellbore in the event of a simultaneous absence of hydraulic supply and control of both subsea control pods.

3.1.20**deepwater well**

Offshore well where subsea BOPs are used.

3.1.21**design factor**

Minimum acceptable ratio of the capacity of a component to the load to which it can be subjected.

3.1.22**drilling margin**

drilling window

operating margin

The difference between the maximum pore pressure and the minimum effective fracture pressure. It is used while drilling and can be determined for any point within an open-hole interval.

NOTE Drilling margin is usually expressed in terms of equivalent mud weight.

3.1.23**emergency disconnect package****EDP**

Equipment that allows a completion/intervention riser to be disconnected from the lower riser package in an emergency situation.

3.1.24**emergency disconnect sequence**

Upon human activation, provides automatic closure of the wellbore and automatic disconnect of lower riser package when specific emergency conditions occur on a floating drilling vessel.

3.1.25**fracture stimulation**

hydraulic fracturing

A stimulation technique used to create a fracture in the reservoir formation to increase productivity of the well.

NOTE Proppant is used in the fracturing fluid to hold the fracture open, thus maintaining a high conductivity path into the wellbore.

3.1.26**heat checking**

A pattern of cracks on a metal surface caused by frictional heating followed by rapid quench cooling.

3.1.27**horizontal tree**

A system of valves installed on a subsea wellhead that has a master valve in the horizontal outlet from the vertical bore rather than in the vertical bore.

3.1.28**hydrostatic barrier**

fluid column barrier

Hydrostatic pressure of a fluid column sufficient to prevent formation fluid influx into the wellbore.

3.1.29**indirect displacement**

Staged (multi-step) displacement from one kill weight fluid to another (typically drilling mud to completion brine) in which an intermediate step involves a non-kill-weight fluid (e.g. seawater) being circulated into the well.

3.1.30**inflow test**

negative test

negative differential test

A test in which the hydrostatic pressure is reduced such that the net differential pressure direction is from the formation into the wellbore.

3.1.31**kill-weight fluid**

Fluid with sufficient density such that the hydrostatic pressure of the fluid column is greater than formation pressure.

3.1.32**landing string**

Jointed pipe used to run casing strings, liners, or tubing.

NOTE A landing string can be designed to have a higher load capacity and is often inspected to a higher acceptance criterion than a string used for drilling.

3.1.33**lower riser package**

LRP

Used for intervention, flowing or vertical tree installation. It contains a series of isolation and cutting valves as part of, or in addition to, the emergency disconnect package.

3.1.34**maximum anticipated surface pressure****MASP**

A design load that represents the maximum pressure that can occur at the surface during well construction or production.

3.1.35**maximum anticipated wellhead pressure****MAWP****MAWHP**

The highest pressure predicted to be encountered at the wellhead in a subsea well.

NOTE It may be calculated for each hole section during well construction.

3.1.36**mechanical barrier**

Subset of physical barriers that features engineered, manufactured equipment.

NOTE Does not include set cement or a hydrostatic fluid column.

EXAMPLES Permanent or retrievable bridge plugs, downhole packers, wellhead hanger seals, and liner hanger seals.

3.1.37**metocean**

Meteorological and oceanographic data, such as wind, wave, water current, and tidal condition measurements.

3.1.38**mudline shut-in pressure**

Internal pressure at mudline assuming that the mud in the hole is fully or partially replaced by a hydrostatic column of formation fluid supplied by its reservoir at its depth and static pressure.

3.1.39**nonaqueous fluid****NAF**

An emulsion where the continuous phase is a water immiscible fluid (i.e. synthetic or mineral oil) and water (commonly brine) is the discontinuous, dispersed internal phase.

3.1.40**open water**

Column of seawater between the subsea wellhead and floating rig without the riser installed.

3.1.41**operational barrier**

A human action or response that results in the activation of a physical barrier, thereby enhancing the total system reliability.

NOTE Operational barriers by themselves do not constitute a physical barrier.

EXAMPLES Process to close BOPs; the detection of an influx.

3.1.42**physical barrier**

Material object or set of objects intended to prevent the transmission of pressure and fluid flow from one side of the barrier to the other side.

NOTE 1 The barrier is designed to withstand all anticipated pressures at its relative position in the wellbore. It may be verified by testing to its full-anticipated load or verified by alternative evaluation (refer to 5.3.2).

NOTE 2 Includes mechanical barriers, cement barriers, and hydrostatic barriers.

NOTE 3 Does not include operational barriers.

3.1.43**piloted hydraulic**

Type of control system that uses individual hydraulic lines to actuate a subsea valve in the control pod, which allows hydraulic actuation fluid flow to function a BOP component.

3.1.44**pipe ram**

A closing and sealing component in a ram blowout preventer that seals around the outside diameter of a specific size tubular in the wellbore.

3.1.45**ram blowout preventer**

Blowout preventer that uses two opposing metal elements (rams) with integral elastomer seals to contain pressure within a wellbore.

NOTE Rams may be designed to close on a specific pipe size (fixed pipe rams), a range of pipe sizes (variable bore rams), or open hole (blind or blind/shear rams).

3.1.46**riser margin**

The difference between the hydrostatic pressure generated by the mud column in the riser to the mud line and the hydrostatic pressure generated by the seawater column to the mud line.

3.1.47**riserless casing string**

A string run in open water prior to the subsea stack being landed.

3.1.48**safety and environmental management system****SEMS**

Structured set of interdependent doctrines, documents, and principles that are intended to ensure that the activities of an organization are directed, planned, and conducted safely.

3.1.49**shoe track**

The space inside the casing between the float/guide shoe and the landing/float collar.

NOTE This space provides a volume that helps prevent over displacement of the primary cement job; thus, the shoe track is typically filled with cement or a cement-mud combination due to wiper plug mud film displacement.

3.1.50**stakeholder**

A person or organization that is affected or can be affected by an organization's actions and policies.

3.1.51
standard operating procedure
SOP

A detailed written procedure used to safely execute a recurring work process in a consistent manner.

3.1.52
stationkeeping

Maintenance of a vessel's desired operating position or station (within stated tolerances) relative to the wellhead or to another vessel.

3.1.53
stop work authority
SWA

A process that provides all operator and contractor/service personnel, directly or indirectly involved with the operation, the responsibility and authority to cease work until a review of the activity can be concluded and it has been found safe to resume such activity.

3.1.54
string

Assembly of individual tubular joints.

EXAMPLES Casing, drill pipe, tubing, etc.

3.1.55
subsea blowout preventer

A series of ram blowout preventers and annular blowout preventers designed to be installed as a unit on a subsea wellhead, tubing head, or subsea tree.

3.1.56
subsea tree

A system of valves placed on the subsea wellhead designed to control the flow into or out of the completed well.

NOTE The subsea tree may provide numerous additional functions [e.g. chemical injection points, well intervention means, pressure relief means (annulus vent), etc.].

3.1.57
surface cement plug

The shallowest cement plug set below the mudline for well abandonments.

3.1.58
surge

An increase in downhole pressure that occurs when a string is lowered in the well or when circulation is initiated.

3.1.59
swab

The lowering of the hydrostatic pressure in the well bore due to upward movement of tubulars and/or tools.

3.1.60
test ram

A ram installed in the lowest cavity of a BOP stack that is designed to hold pressure from above and seals around the drill string (used to facilitate BOP testing operations).

3.1.61**tested barrier**

A barrier whose performance has been verified through meeting the acceptance criteria of a pressure test in the direction of flow and to a pressure differential equal to or greater than the maximum differential pressure anticipated during the life of the barrier.

3.1.62**total system reliability**

system reliability

well total system reliability

The probability over time that the combination of all physical and operational barriers will prevent unintended flow of fluid or gas.

3.1.63**trip margin**

Additional drilling or completion fluid density that provides an increment of overbalance pressure in order to compensate for effects of swabbing.

3.1.64**validation**

A quality assurance process of establishing evidence that provides a high degree of assurance that a product, service, or system will accomplish its intended purpose.

NOTE This often involves acceptance of fit-for-purpose with end users and other product stakeholders.

NOTE 2 In this document, the related term “validation” is used only with respect to the initial design of equipment (i.e. capacity calculations and any performance confirmation tests in a lab rather than in the well).

3.1.65**variable bore ram**

A pipe ram that seals on more than one pipe size.

3.1.66**verified barrier**

Barrier whose proper deployment has been substantiated through a postinstallation assessment or through observations recorded during its installation.

NOTE A tested barrier has the greatest level of assurance.

EXAMPLE Observations that can be recorded during a cement displacement operation to support the evaluation of the cement as a barrier include a mud displacement volume equal to the calculated capacity of the casing string, and observed lift pressure matching the calculated lift pressure.

3.1.67**verify/verification**

A quality control process used to evaluate whether or not a product, service, or system complies with a given criteria set (i.e. regulations, specifications, or conditions).

NOTE Verification can be in development or production phases (often an internal process).

3.1.68**vertical tree**

Subsea tree with the master valve in the vertical bore of the tree below the side outlet.

3.1.69**watch circle**

Area of predetermined size in which the drilling rig maintains its intended position (station) in order to not exceed equipment or reaction time limitations.

NOTE If the rig moves to the edge of the watch circle, then attention is heightened.

3.1.70**well control**

Activities implemented to prevent or mitigate an unintentional release of formation fluids and gases from the well to its surroundings.

3.1.71**well test**

Flowing reservoir fluids to the surface to evaluate the reservoir and the completion.

3.2 Abbreviations

AAV	annulus access valve
APB	annular pressure buildup
BHP	bottomhole pressure
BHST	bottomhole static temperature
BOP	blowout preventer
BSR	blind shear ram
C/K	choke and kill
CRA	corrosion resistant alloy
DW	deepwater
ECD	equivalent circulating density
EDP	emergency disconnect package
EDS	emergency disconnect sequence
ESP	electric submersible pump
ETG	expandable tubular goods
FIT	formation integrity test
FOSV	full-opening safety valve
HPWHH	high pressure wellhead housing
HTH	horizontal tubing hanger
ID	inner diameter
ITC	internal tree cap
LMRP	lower marine riser package
LOT	leak-off test
LPWH	low pressure wellhead housing
LRP	lower riser package
LTP	liner top packer
MASP	maximum anticipated surface pressure
MAWHP	maximum anticipated wellhead pressure
MOC	management of change
MUX	multiplexed

MYS	minimum yield stress
NAF	nonaqueous fluid
OD	outer diameter
PBR	polished bore receptacle
QA	quality assurance
QC	quality control
ROV	remotely operated vehicle
RP	recommended practice
SCSSV	surface controlled subsurface safety valve
SEMS	safety and environmental management system
SRB	sulfate reducing bacteria
SSTT	subsea test tree
SWA	stop work authority
SWF	shallow water flow
TD	total depth
TLP	tension leg platform
TOC	top of cement
VIT	vacuum insulated tubing
WBM	water-based mud
WOC	waiting on cement

4 Deepwater Rig Systems and Subsea Configurations

4.1 General

Specialized rig systems are required to support DW well construction operations. DW wells may be designed for various purposes such as:

- exploration,
- appraisal,
- well testing (short or long term),
- production or injection (subsea well or tied-back to a dry tree production system such as a TLP or spar),
- utility (monitor or relief well).

Although outside the scope of this document, a brief description of production operations is included for background information. The production facility in DW may be bottom supported (e.g. fixed platform or compliant tower), vertically moored (e.g. tension leg), or a floating system (e.g. spar, semisubmersible, or ship-shaped). Production may be processed on the production facility prior to export to a tanker or through an export riser and pipeline system. Production comes onboard the facility through production risers. The production risers may tie directly to a DW well, floating system, or to a flowline gathering system that is tied to one or more subsea wells.

Water depth, well depth, and well type vary in DW operational areas. Deeper wells with heavy intermediate strings can require high load capacity rigs. Weather considerations (i.e. hurricanes) and

infrastructure proximity (i.e. pipelines or platforms that could be affected by rig movement or dragging anchors) can also determine rig type and mooring. For drilling and completion activities with floating rigs and subsea BOP systems, the typical rig and system options are described in Table 1.

Table 1—Typical Rig and System Options

System	System Options
Rig type	Drillship or semisubmersible
Stationkeeping method	Dynamically positioned or moored
Blowout preventer control system	Piloted hydraulic or electro-hydraulic (multiplex)
Subsea tree type	Vertical or horizontal tree

When designing a well, certain aspects of the design may assume the use of a particular type of rig, typically moored or dynamically positioned. However, the possibility that a different type of rig could be used during other stages of the well's life cycle should be considered during the well design process.

4.2 Rig Options

DW rigs are usually ship shaped (drillships) or semisubmersible. Alternate configurations can also be used. Drillships and semisubmersibles may be dynamically positioned or moored. Wells can also be drilled in DW using a rig either temporarily or permanently installed on a floating production platform. However, this configuration is outside the scope of this document unless the BOP stack and lower marine riser package (LMRP) are located on top of the wellhead at the mudline.

The water depth rating of DW rigs is ultimately limited by the installed marine riser tension load capacity and/or mooring system capacity. The load imposed on the rig by the marine riser is dependent on water depth, marine riser buoyancy used, environmental conditions and maximum mud weight required.

4.3 Stationkeeping System

4.3.1 General

DW rigs maintain station (staying positioned over the wellhead location on the seafloor, within an operationally defined radius) by using either a mooring system or a dynamic positioning system.

4.3.2 Mooring System

Mooring systems are designed to keep rigs on location by exerting a restoring force on the rig when metocean conditions push the rig away from its station over the well. Anchors in the seabed are attached to the rig using large chains or lines. Mooring system configurations are often described based on the ratio of the water depth to anchor radius as follows: catenary mooring (typically 1:2 or greater); semitaut (typically 1:1.4); and taut (typically 1:1). The mooring system components vary depending on the system configuration. DW catenary and semitaut mooring systems are often comprised of steel wire and chain segments. Taut mooring systems will usually incorporate synthetic rope segments.

The mooring system design can vary depending on the metocean conditions and the potential damage to nearby facilities. A single exploration well most likely has lower design factor requirements than a multiwell program that will require an extended drilling period with environmental extremes. Special precautions are required when mooring systems are deployed in the vicinity of other assets such as moored surface facilities [e.g. tension leg platform (TLP); spars; or floating production, storage, and offloading systems] and subsea infrastructure (e.g. pipelines, flowlines, and manifolds). Mooring system deployment considerations include the potential damage caused by dropping anchors, dragging anchors or collision with adjacent facilities.

A limit state analysis and risk assessment are integral considerations when assessing mooring systems. Refer to API 2SK for additional information about mooring systems.

4.3.3 Dynamic Positioning System

Dynamic positioning systems are commonly used for stationkeeping on DW drilling rigs. These systems use information on the rig's current location (e.g. as determined by a global positioning system and acoustic sensors) to control thrusters, which act to restore the rig to a position over the well's center. Dynamically positioned drillships and semisubmersibles optimize stationkeeping by keeping the bow pointed in the direction of the metocean conditions.

Rig position offset creates bending loads in the marine riser system, subsea BOP, wellhead connector, subsea wellhead, and structural casing. These loads have the potential to be higher when using dynamically positioned rigs compared to moored rigs in the same water depth. This is because the assumed rig offset and associated loads that occur with a failure of the dynamic positioning systems are higher than the failure case for a moored system.

The rig offset-induced bending loads can be an especially important consideration if a well was initially planned to be drilled using a moored rig, but is instead drilled or reentered using a dynamically positioned rig. The structural capacity of the well should be designed for current and future rig types.

Refer to API 2SK for additional information on dynamically positioned rigs.

4.3.4 Metocean Criteria and Loading

Metocean conditions at or near the location of a DW well are an important component in the well design, its construction and operation. In general, metocean analysis considers the statistical probability of a storm event impacting the well's location. Important metocean phenomena to be considered are primarily wind, wave, and current (tides having a secondary effect). These phenomena are converted into loads applied to the rig and its riser to determine the rig's suitability to work at the location during the anticipated season(s). These loads can sometimes be managed or minimized by changing the heading of the rig or by adjusting the tensions on different anchoring lines.

Seasonal variation of metocean conditions is a key consideration for most locations. There can be significant differences in the metocean conditions during tropical or winter storm events versus day-to-day operations. Rig selection should consider whether the stationkeeping system can withstand the expected variation of these conditions at the well location. The range of metocean conditions can differ greatly if the rig is drilling a short-duration well during the more benign part of the calendar, compared with an extended drilling campaign stretching over multiple years in the same location. Examples of considerations include: rig survivability, riser survivability, anchor tension, rig heading for ship-shaped vessels, watch circles, and evacuation procedures.

DW well operations can be affected by different types of currents. Tidal currents are typically weak in DW, but circulation currents can be quite significant. Circulation currents are relatively steady, large-scale features of the general oceanic circulation. An example is the Loop Current in the Gulf of Mexico, where surface velocities can be in the range of approximately 2 knots to 4 knots at the surface, declining with water depth. While relatively steady, these circulation features can meander and intermittently break off from the main circulation feature to become large-scale eddies/rings, which then drift at a speed of a few kilometers per day. Velocities in such eddies or rings can approach or exceed that of the main circulation feature. Circulation currents generally will not change in magnitude or direction in a dramatic fashion. Rather changes in these currents will typically be gradual and on the order of days rather than hours.

Other current types can also be present. Rossby waves are currents with a period of several days that can occur near escarpments (such as the Sigsbee escarpment). They can generate up to 3.6 knots at the surface with 2 knots at the mudline. Inertial currents are increased currents at depth that typically reach their maximum rate several days after a storm passes the location (compared with the largest surface

currents that typically occur simultaneously with the storm's passage). For certain types of currents, the profile of the current within the water column can have a significant impact on riser loading, fatigue, and rig stationkeeping.

Refer to API 2INT-DG for guidance on hurricane-induced conditions and API 2MET for metocean conditions.

4.4 Marine Drilling Riser System

The rig is connected to the subsea wellhead with the marine drilling riser system. The riser is a conduit for equipment and for fluid circulation between the rig and the seafloor. The riser system supports the tension load applied to keep it aligned between the rig and the wellhead, along with the weight of the control lines and service lines. The riser joints include smaller, high-pressure choke and kill (C/K) lines that facilitate high-pressure circulation and well control operations. The riser system features either electrical or fiber optic cables to carry multiplexed (MUX) signals or hydraulic lines to carry pilot signals to the control the BOP and EDS systems. Specialty components (e.g. telescopic joints and tension ring) at the top of the riser system allow the rig to move up, down, and to rotate relative to the riser. Additional information can be found in API 53 and API 16Q.

Figure 1 provides an example of a marine drilling riser system.

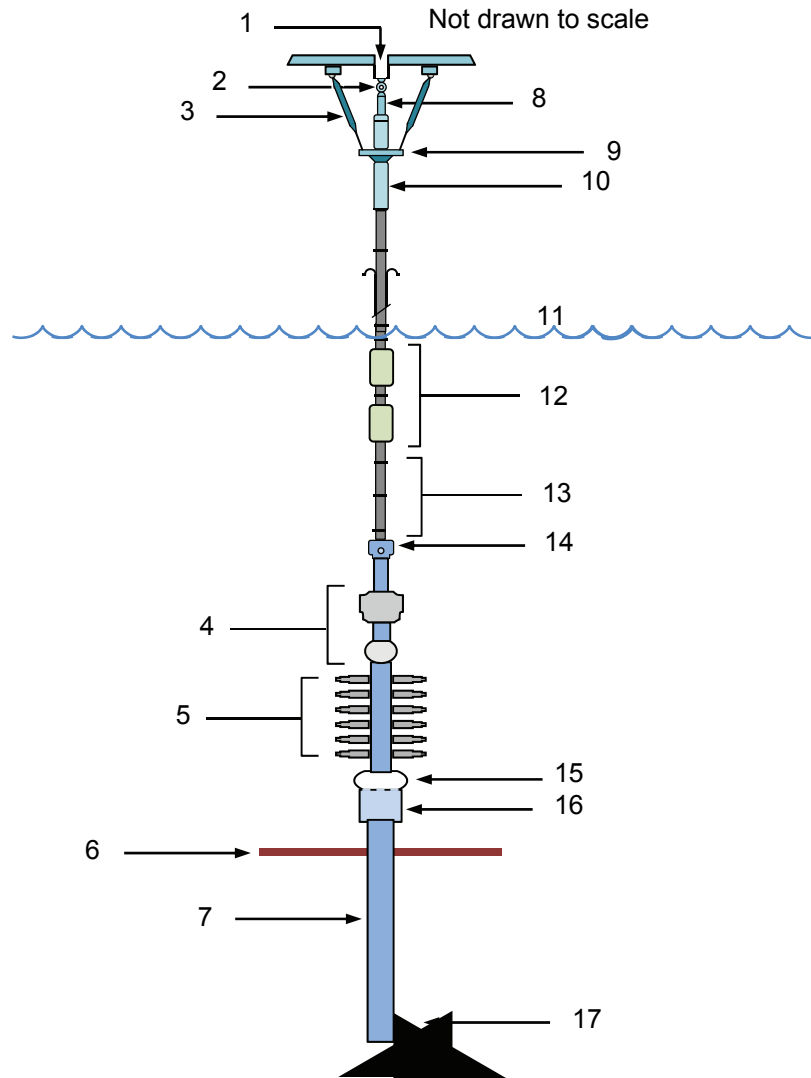
4.5 BOP System

A subsea BOP system supports both well control and operational functions. Key functions include:

- well control—stop formation fluid influx and control existing influx during the kill operation through activation of an additional barrier;
- provide the ability to shear drill pipe, tubing, casing or other components and allow rapid release of the LMRP from the BOP stack;
- seal the well by providing a barrier to replace the loss of hydrostatic pressure in the event of a drilling riser disconnect or mechanical failure of the riser;
- provide a means of pressure testing wellbore sealing elements.

The subsea BOP incorporates multiple elements designed to close around the different sizes of drill pipe, casing, or tubing used in the well construction process. This allows circulating an influx out of the wellbore or bullheading the influx back into the formation through the C/K lines and the choke manifold. The BOP also provides the functionality of testing wellbore equipment (e.g. casing, cement, packoffs, etc.). The BOP elements and valves, are closed, pressure is applied down either the choke or kill line with the response monitored at the rig floor.

Blind shear rams (BSRs) are capable of shearing certain tubulars in addition to sealing the wellbore. A tubular may not be shearable in a particular BOP system or under certain well or operating conditions due to the size, wall thickness or material properties of that tubular. However, while some shearing elements (e.g. casing shear rams) are more capable of shearing large diameter or heavy wall tubulars, they may not be designed to seal the wellbore. Refer to API 53 and local regulations for guidance on BOP configurations.

**Key**

1 diverter housing	7 structural casing	13 bare joints
2 upper ball or flex joint	8 telescopic joint inner barrel	14 riser adapter and lower flex joint
3 tensioners—direct-acting (or wire rope)	9 tension ring	15 wellhead connector
4 LMRP	10 telescopic joint/outer barrel	16 high pressure wellhead housing
5 BOP	11 sea level	17 casing shoe
6 mudline	12 buoyed joints	

Figure 1—Marine Drilling Riser System Example

The stack consists of the following two sections.

- a) The LMRP contains one or more annular type BOP, which can close and seal on a wide range of pipe sizes. It is important to note that while the annular sealing elements are the most versatile sealing elements in the BOP, they normally have a lower working pressure than ram type BOPs and are most effective when sealing against pipe. The LMRP also contains the control pods (which actuate BOP functions) and a subsea connector that allows for the riser to be disconnected from the BOP stack.

b) The BOP stack contains ram-type elements and may contain an annular BOP. These elements can include:

- fixed pipe rams,
- variable bore rams,
- shearing rams,
- test rams,
- BSRs, and
- blind rams.

Sealing elements (annulars or rams) are designed to seal against pressure exerted from the wellbore. While all rams are designed to hold their stated pressures in one direction (typically in the direction of hydrocarbon flow), they are not all designed to hold the same level of pressure in the opposite direction (thus potentially creating a leak path during a negative test). On some rigs, an inverted ram or a specially designed bidirectional ram (test ram) is used to hold pressure from above, eliminating the need for a test plug or tool during BOP pressure tests or negative testing of barriers. A variable bore ram is a standard pipe ram that seals on a range of pipe sizes using a special elastomer and elastomer support mechanism that adapts to the pipe size during the closing operation.

The C/K line system is considered part of the BOP system. When the BOP is closed, the C/K lines provide a means to circulate fluids into or out of the well, circulate out a kick, monitor pressures and test the BOP. When operating in deeper water depths with longer C/K lines, the use of large inner diameter (ID) lines can improve circulation and well control capabilities by reducing dynamic friction loss through these lines.

It is critical that the BOPs and wellhead system have sufficient structural integrity to withstand the combined pressure, tension, and bending loads. Subsea BOPs contain elements and valves joined together with either flanged, studded, or clamp hub connections. C/K line outlets are subjected to bending loads from the pressure end loads applied to the ID of the C/K line at the lower-most valve. The bending resistance of BOP connections is reduced as internal pressure increases. To provide additional assurance the BOP component connections do not leak under combined pressure and bending loads, methods of resisting the bending loads may be included in the BOP frame design. Additional information about API flange connections can be found in API 6AF, API 6AF1 and API 6AF2.

Periodic BOP system inspections shall be conducted to meet or exceed the provisions established in API 53.

4.6 BOP Control System

4.6.1 General

BOP functions are controlled using several methods such as direct, piloted, electro-hydraulic, and MUX. One method employs piloted hydraulic controls. In this case, a hydraulic signal is transmitted from the surface control station to the subsea BOP. A hydraulic pilot valve receives the signal triggering the actuation of the subsea function. Because the hydraulic signal travels slowly, this type of control is best suited for use in shallower water depths. Another type of control uses electro-hydraulic technology. Systems in deeper water depths use multiplexed electrical or fiber optic signals sent from the surface to the pods to actuate the function on the subsea BOP.

To increase the reliability of the control system, two independent control pods (located on the LMRP) provide separate communication paths to the BOP (which can be selected at the surface control panel).

The selected control path to activate BOP functions is through either the blue pod or the yellow pod on the LMRP (refer to Figure 2).

Most DW rigs use electronic BOP control systems based on MUX communication protocols that transmit signals in milliseconds. MUX systems are highly complex, and their multiple hydraulic/electric interfaces require diligent maintenance and testing. Some systems have batteries installed in the pod, and in those cases it is important to consider how to maintain the power in those batteries. Modern MUX systems provide multiple levels of system redundancy beyond being able to select the blue or yellow pod control system paths.

With either piloted hydraulic or MUX systems, the control system is used to direct the flow of hydraulic fluid to various hydraulically operated components in the BOP system. The control system valve package (commonly referred to as the pod) is where the individual surface-generated control signals activate the selected valve to direct hydraulic fluid to the required BOP function (for example, to close a pipe ram). Hydraulic fluid is provided via a conduit line, or hose from the surface high pressure unit. The typical DW 5000 psi accumulator supply pressure is commonly regulated to a lower operating pressure to actuate specific BOP functions. BOP hydraulic fluid is a water-based fluid with soluble oil additives for lubricity and corrosion control.

Verification feedback to the BOP control panels on the rig includes the volume of BOP control fluid and pressure used to activate a function. Any discrepancy between the indicated and the expected volumes should be noted and investigated.

NOTE The expected operating volume is determined during prior testing of the BOPs.

Any modifications from the original design or the intended function of the BOP and control system shall require a documented risk assessment by the contractor to accompany the required MOC.

Additional information about BOP control systems can be found in API 16D and in API 53.

4.6.2 Remotely Operated Vehicle Panel

The BOP stack should be equipped with the following minimum (critical) ROV intervention capability to:

- close each shear ram (and lock),
- close one pipe ram (and lock), and
- unlatch the wellhead connector.

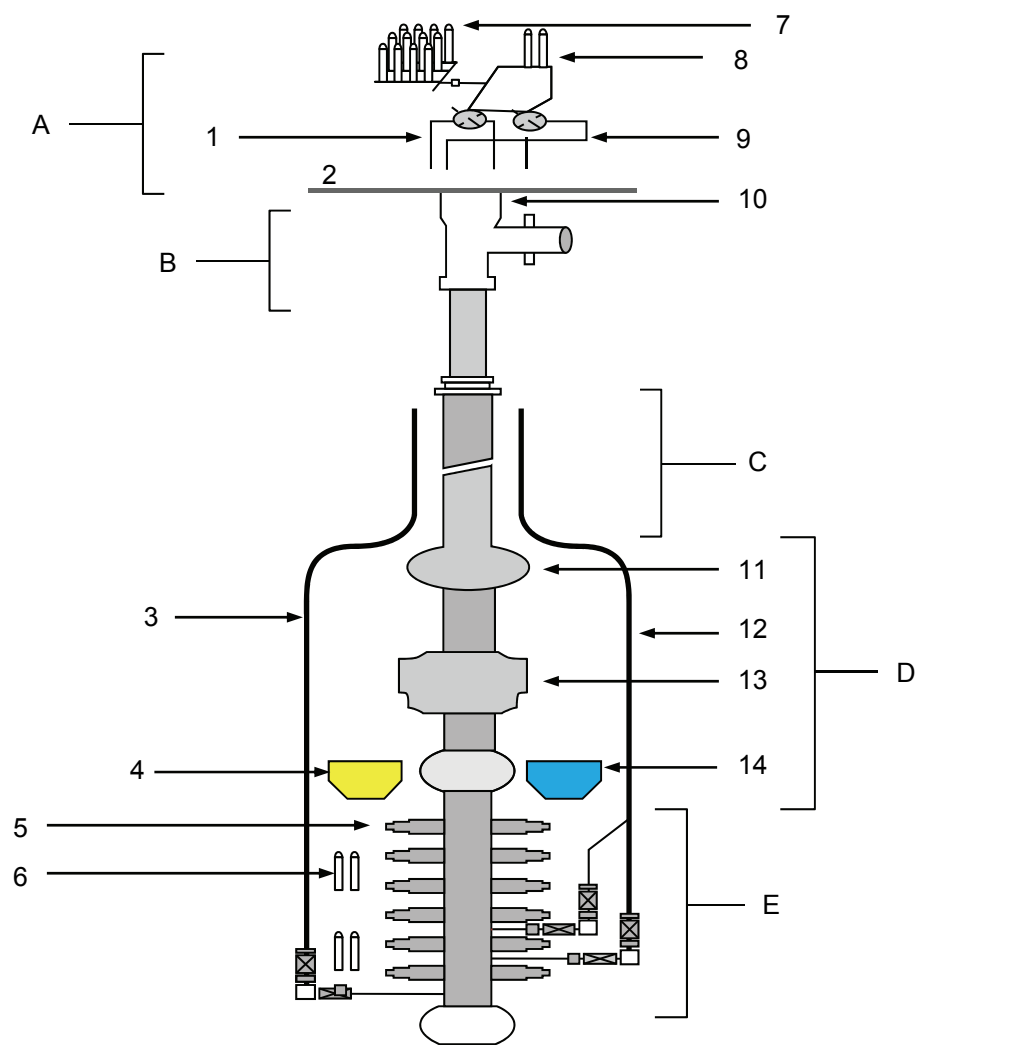
A hydraulic power source able to interface with the ROV panel shall be available on the rig and ready for deployment when the BOP is installed on the subsea wellhead.

All critical functions shall be fitted with API 17H high-flow receptacles. Critical functions shall be color designated for quick identification, to differentiate the critical functions from the noncritical functions.

Frequency of testing and acceptance criteria shall be in accordance with API 53 and local regulations. Additional information about ROV interface panels can be found in API 16D.

4.6.3 Acoustic System

Secondary control of key functions can also be provided via an independent acoustic BOP control system that can be activated using a matching portable acoustic control unit on the rig or nearby vessel. The reliability of acoustic systems can be adversely affected by thermoclines, currents, and vessel noise (i.e. during a drive-off). Additional information on BOP control system functions can be found in API 16D.



Key

A	control system	1	line to yellow pod	6	subsea accumulator bottles	11	flex joint
B	diverter assembly	2	rig floor	7	surface accumulator bottles	12	choke line
C	riser assembly	3	kill line	8	pilot bottles	13	annular BOP
D	LMRP	4	yellow pod	9	line to blue pod	14	blue pod
E	BOP stack	5	rams	10	diverter		

Figure 2—BOP Controls

4.7 Emergency Functions

4.7.1 General

Secondary BOP control functions described in 4.7.2 through 4.7.6 can be used to establish control of the well under specific conditions. Consult API 53 and local regulations for required secondary functions, along with surface and subsea testing of those systems. Surface and subsea test frequency shall be determined in accordance with API 53 and local regulations for the emergency disconnect sequence (EDS), deadman, and autoshear systems.

4.7.2 Emergency Disconnect Sequence

The EDS is a manually-activated function programmed to shut the well in and disconnect the LMRP from the BOP stack, based on the well conditions and vessel-specific operating criteria. There is no system or trigger mechanism that automatically begins the EDS sequence. It is manually activated by pushing the EDS button. An EDS is normally limited to rigs with dynamic positioning systems.

The EDS sequencing varies depending on the specific system, anticipated disconnect scenario, and input from the contractor, and operator. For example, the order of disconnect may begin with the casing shear rams (nonsealing), followed by the BSRs (sealing). The accumulator volume and pressures, ram operator system pressures, and ram shearing capabilities should all be considered in the design. The frequency of testing and acceptance criteria shall be in accordance with API 53 and local regulations.

If the marine riser is suddenly disconnected with a full mud column, the collapse loads induced by the falling mud column should be considered.

4.7.3 Deadman

A deadman system shall be installed, tested and available on all moored and dynamically positioned rigs, where subsea BOPs are installed, in accordance with API 53 and local regulations. When the deadman system is activated under intended conditions, it does not require human initiation. The subsea accumulator volume and pressure required to secure the well in the event of a complete loss of electrical power, communications and hydraulics to the subsea control system, shall be determined for the system installed, in accordance with API 16D. Some deadman systems rely on subsea battery power to operate. If this is the case, procedures should be in place to monitor or track the charge state of the battery pack.

If the electrical or hydraulic communication link to only one pod is lost, the deadman will not activate. A typical design includes a fail-open valve that blocks subsea accumulator supply to the BSRs (when powered). Upon sensing the loss of hydraulic supply and electrical power from both pods, the valve opens and the BSRs close. Other secondary functions may be attached to the deadman system such as closing of C/K fail-closed valves (loss of pilot pressure) or LMRP disconnect.

Standard operating procedures for pod reactivation, including control logic to prevent the BSR from inadvertently opening when power is reestablished to the BOP stack after a disconnect, shall be established. These procedures shall also be included in the deck testing of the system prior to deploying the BOP.

4.7.4 Autoshear

Autoshear is a safety system that is designed to automatically shut-in the wellbore in the event of an accidental disconnect of the LMRP. When the autoshear is armed, the shear rams close when the LMRP is disconnected. Since this system must operate rapidly despite having lost the connection to the rig, a separate accumulator system is used for the autoshear and deadman.

NOTE This accumulator system may also be used to operate the ROV and acoustic systems.

The autoshear system is occasionally disarmed according to company-specific and rig-specific procedures, typically when nonshearable components are positioned within the stack. However, a MOC should be used if the autoshear system is disarmed for other reasons (i.e. a leak in bottle or manifold).

When moving the BOPs between wells, the benefits of retesting the system subsea versus the risk of damaging the well or rig equipment if the BOPs are pulled to surface for testing should be considered.

Frequency of testing and acceptance criteria shall be in accordance with API 53 and local regulations.

4.8 Subsea Wellhead and Production Tree Configurations

A low pressure wellhead housing (LPWH) is welded to the structural casing and serves as foundational structure for the HPWHH. A permanent guide base, when used, attaches to the LPWH.

The high pressure wellhead housing (HPWHH), with its welded extension, is attached to the top of the surface casing. The wellhead provides an external connector profile to which the subsea BOP stack is attached. It has several internal profiles for casing hangers, running tools, and seal assemblies. It is normally latched and often preloaded to the LPWH to increase both bending and rotational resistance.

For wells that will be completed, the subsea production tree is attached to the HPWHH. There are two types of subsea production trees: vertical and horizontal. A vertical subsea tree can require a tubing spool.

The type of subsea production tree will have an impact on sequence of completion activities and on the subsea BOP/LMRP configuration for well control during some completion operations.

4.9 Remotely Operated Vehicle Systems

ROV systems can be used in drilling and completion of DW wells. In some operations, multiple ROVs are used to provide redundancy allowing continuous activity in the event of a failure of one ROV. ROVs are used in open water activities before running the BOPs, for secondary (or emergency) activation of the BOP functions and in completion and abandonment activities. A ROV may also provide the following functions in support of the well construction process:

- a) normal/high definition camera for routine inspection of the equipment, riser, and BOP condition during operations;
- b) hydraulic pump to provide seawater or corrosion prevention fluid to activate BOP functions;
- c) compass to determine relative heading of objects with respect to wellhead;
- d) fluid bladder to enable pumping corrosion prevention fluid into wellhead;
- e) sonar for detection of objects;
- f) multifunction arms to rotate bolts to lock/unlock components and pull/reinstall plug-ins;
- g) install, remove, and replace ring gaskets on the subsea wellhead and LMRP;
- h) tooling packages for subsea equipment;
- i) hot-stab capability;
- j) hydrate removal;
- k) hydrate suppression by pumping glycol or methanol;
- l) monitor structural, conductor, and surface pipe running operations;
- m) monitor fluid returns during riserless drilling and cementing operations;
- n) move guidelines and guide posts from one guide base to another.

Refer to API 53 and API 17H (or ISO 13628-8) for additional information.

NOTE Some rigs may use guidelines, installed between the moonpool and the LPWH, which allow a rig-based video system to be run on a cable to monitor operations.

5 Well Design Considerations

5.1 General

The basis for a well design is an understanding of the environment in which the well is to be drilled. Interpretations of local geologic structure, geo-pressure, and formation strengths are derived from local drilling experience or seismic data. It should be noted that uncertainties will exist in the interpretation of the data and ultimately in the description of the geologic environment.

Casing design is based on these interpretations and other factors. For example, location-specific constraints establish the directional drilling program and the required well depth. Production or evaluation requirements will dictate the hole size desired at total depth (TD).

The integration of casing design with barrier planning contributes to increased reliability and well integrity. The resulting well architecture is intended to safely achieve well objectives.

NOTE The terminology used to identify casing types (refer to Table 2) is dependent on local regulations and convention (e.g. surface casing, conductor casing, structural casing).

5.2 Deepwater Well Architecture

The complexity of DW wells has increased over the years as measured by water depth, well depth, mud weights, temperatures, and the number of casing points required to reach the objectives. DW wells now have been drilled in water depths greater than 10,000 ft (3048 m) and to true vertical depths greater than 35,000 ft (10,668 m). Examples of complexities that impact well architecture are provided in the following:

- a) low fracture pressure relative to pore pressure in DW environments (drilling margin);
- b) salt and subsalt hazards such as tar zones or rubble zones;
- c) subsurface geology including shallow water/gas flow hazards and in situ hydrates;
- d) abnormal pore pressure or subnormal pressures (regressions);
- e) metocean (heave compensation as well as mooring during hurricanes and stationkeeping during loop currents);
- f) drilling duration, casing wear, and heat checking of casing due to extended drill pipe rotation and side loads;
- g) thermal fluid expansion and trapped annular pressure loads;
- h) wellhead and hanger load capacities and reduced annular clearance;
- i) BOP limitations [e.g. shear limitations regarding heavy-wall high-strength drill strings, annular element sealing on large outer diameter (OD) casing, and the potential for casing collapse when an annular BOP is closed on large OD casing];
- j) directional requirements;
- k) presence of H₂S (e.g. water flooding);
- l) permanent abandonments, including wellhead removal.

DW well designs have been advanced to safely meet the challenges associated with the progression of well and water depths. A new generation of DW rigs with higher hoisting and pumping capabilities has been developed to implement these designs. To address increased complexity associated with deeper wells, a variety of well architectural designs and construction requirements have emerged as follows:

- the deeper wells and higher mud weights required upsizing drill strings (e.g. from 4 ¹/₂-in. or 5-in. OD drill strings to high-strength 5 ¹/₂-in., 5 ⁷/₈-in., or 6 ⁵/₈-in. OD drill strings) to accommodate the increased axial loads and hydraulics;
- the 13 ⁵/₈-in. casing was then needed at the former 9 ⁵/₈-in. casing depths to reduce the annular circulating friction pressures to acceptable levels;
- setting the 13 ⁵/₈-in. casing deeper in the well required additional large OD casings with semiflush or flush connections (e.g. 18 in. and 16 in.), wellhead modifications and supplemental hanger systems to run more strings through the 18 ³/₄-in. BOPs;
- new generation of landing strings, casing tools, and slips were developed to handle higher loads from running longer, thicker wall casing strings.

Key physical limitations of the drilling rig that impact well architecture are its capacity and ratings (e.g. the number and capacity of the mud pits, variable deck load, derrick hoisting rating and racking capacity, marine riser tensioner capacity, power, BOP size, pressure rating and shear capabilities, etc.). Most DW mobile offshore drilling units are equipped with 18 ³/₄-in. BOPs. The HPWHL limits the size of the first string run below the HPWHL, as it has a smaller internal diameter than the BOPs. Different types of DW casing programs are used to safely achieve well objectives in different downhole conditions. Three possible DW casing programs are illustrated in Figure 3. These are only examples of different casing programs, and they do not capture all of the possible variations in DW well architecture. Refer to 5.2.1, 5.2.2.2, and 5.2.2.3 for more details.

Figure 4 and Figure 5 are cross sections of example wells that illustrate the increased well complexity for a tight clearance casing architecture versus a normal clearance casing architecture. These figures represent only the tube body diameters, and any external connector upsets would further reduce annular clearance. These examples are intended to illustrate the issue of casing and liner clearance. As shown in Figure 3, some of the strings can be run as casing, liners, or tiebacks depending on the selected well architecture.

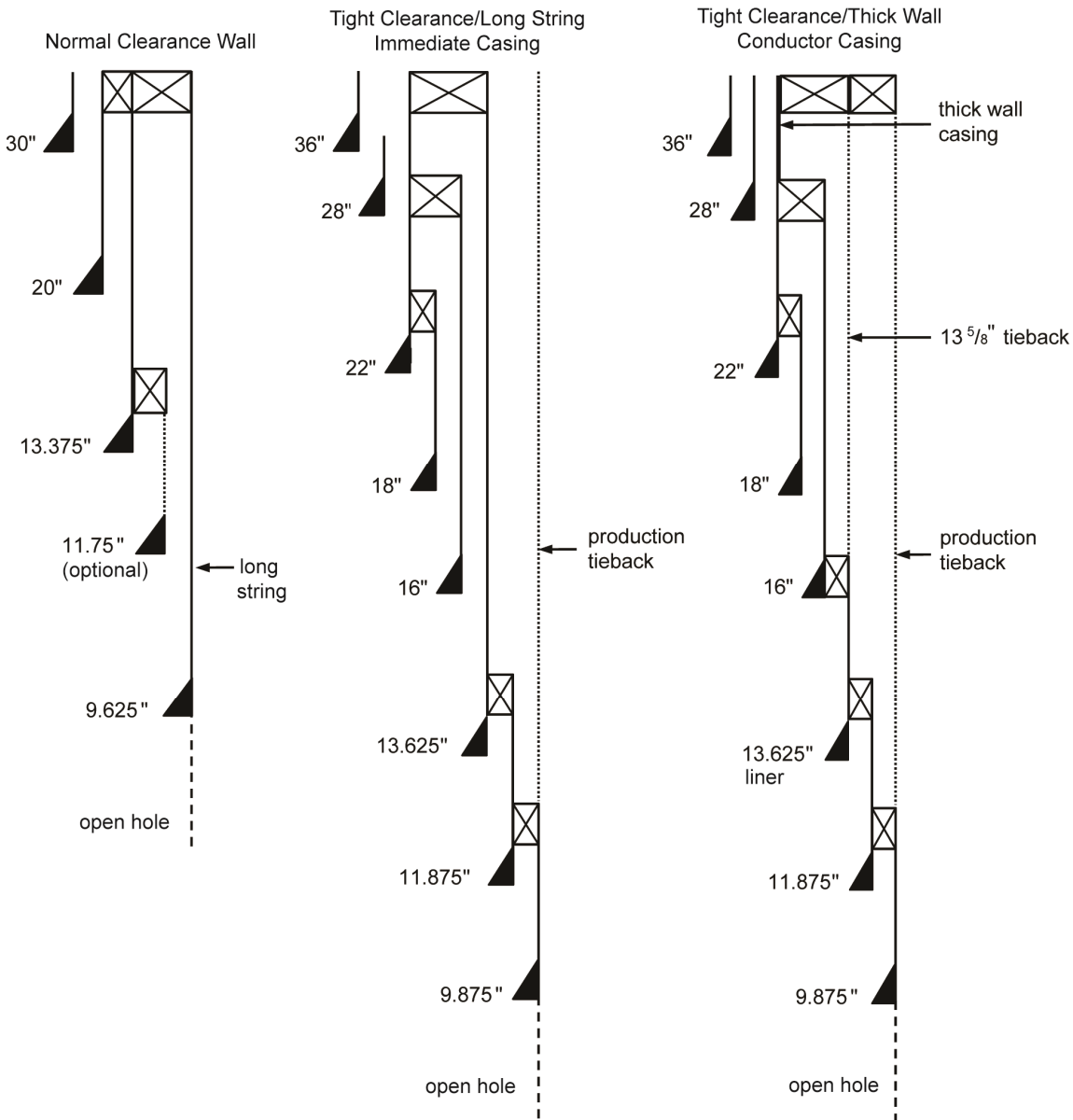
5.2.1 Normal-clearance Casing Well Design

This example well design is employed globally in regions that have low pore pressures relative to fracture gradients and require few casing points to reach TD. Normal-clearance casing well architecture permits the use of standard hole sizes and casing with coupled connections. It usually requires no under-reaming or tight-clearance casings (i.e. no flush or semiflush connections).

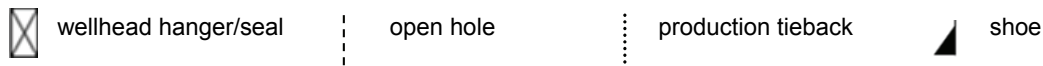
5.2.2 Tight-clearance Casing Well Design

5.2.2.1 General

Tight-clearance well architecture increases the number of casing strings available. This enables drilling of DW wells without major changes to the rig, BOPs, or wellhead when narrow margins exist between pore pressures and fracture gradients.

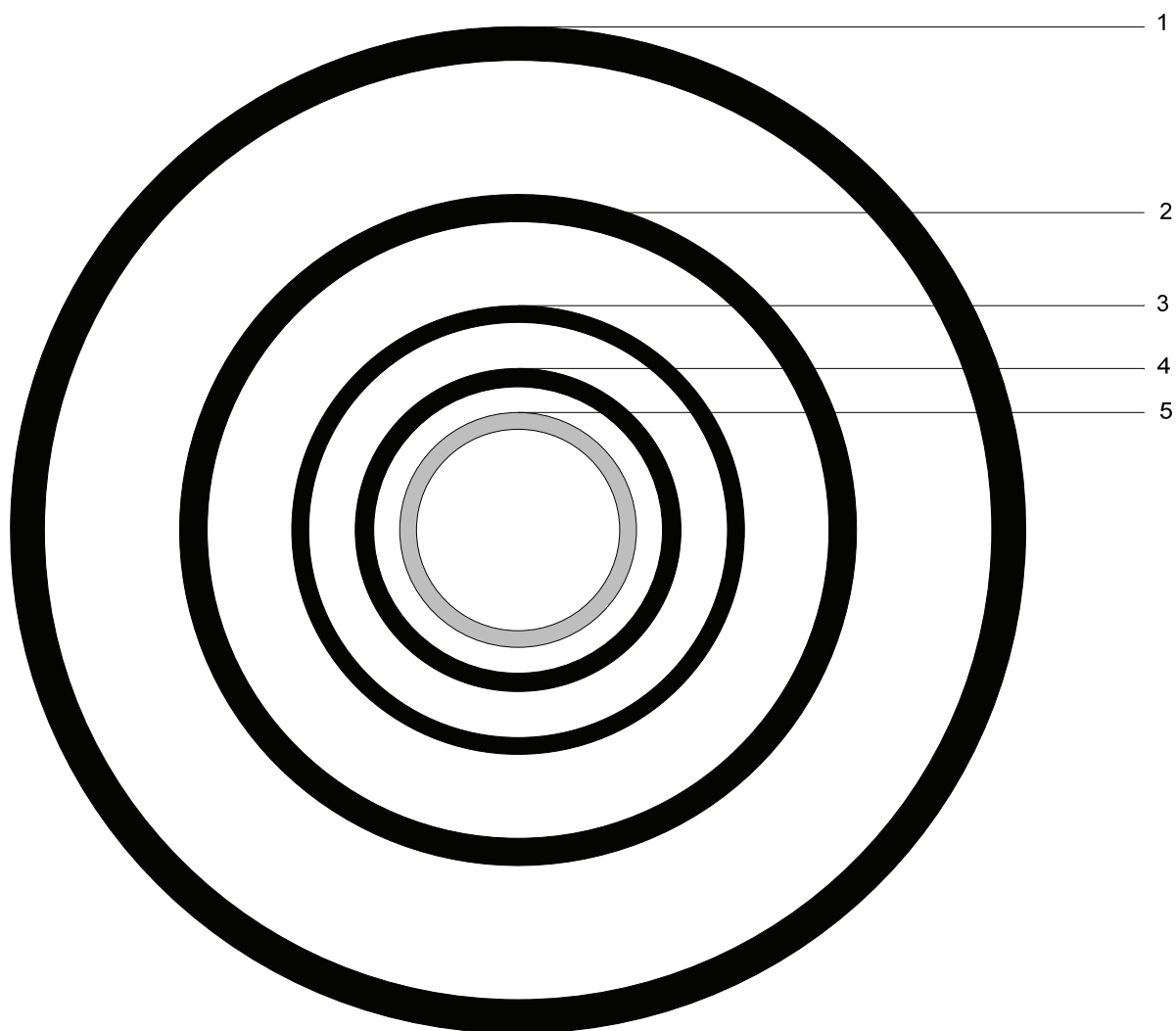


Key



NOTE The size and number of strings varies to meet geological conditions, some strings are optional, and not all possibilities are shown. (i.e. on high pressure wells, 14 in. may be substituted for 13 5/8 in.). Dotted lines indicate potential tiebacks (9 7/8 in. may be hung in 13 5/8 in. on high-pressure wells). Dashed lines indicate possible casing sections or open-hole sections.

Figure 3—Well Architecture Examples



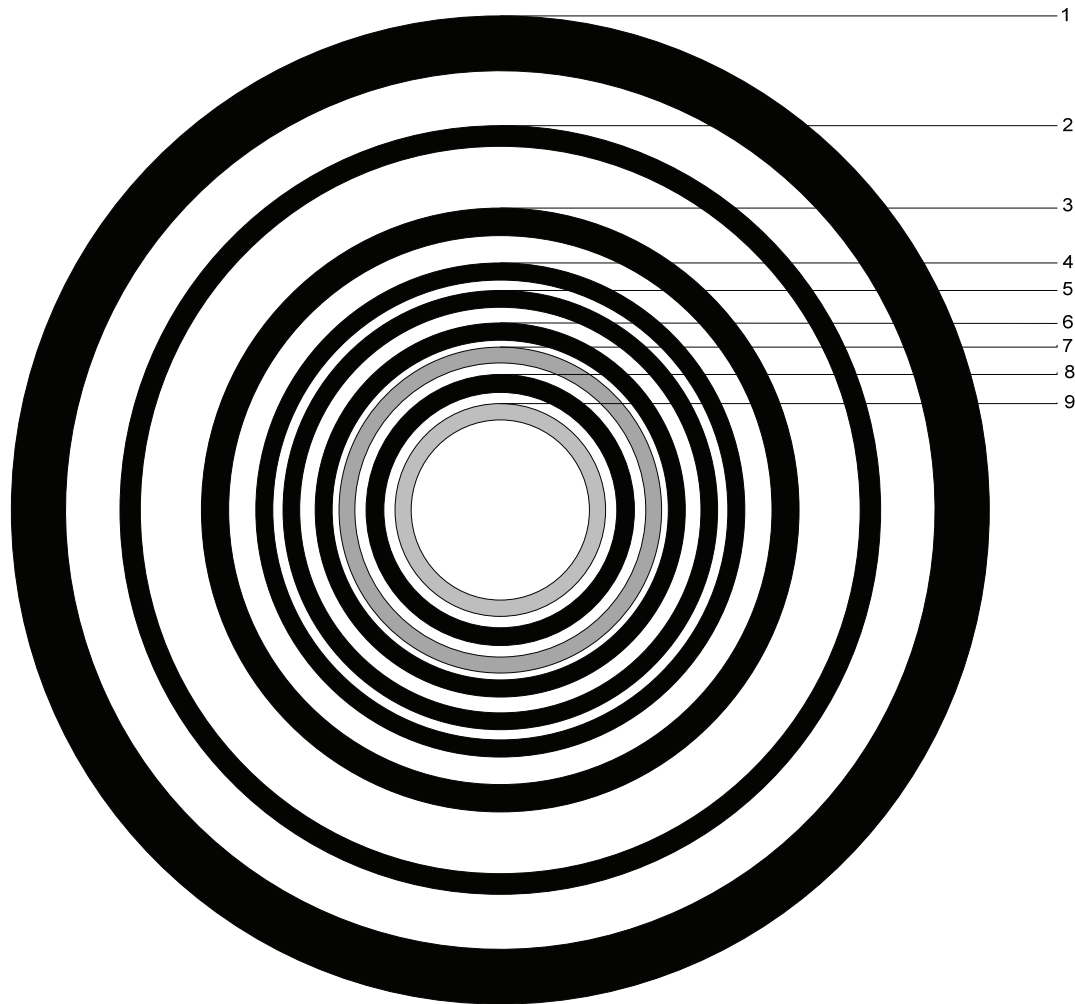
NOTE 1 Black is casing, grey is liner, and white is annulus.

NOTE 2 Drawing to scale.

Key = OD

- | | |
|------------------------|------------------------------|
| 1 30 in. | 4 $9 \frac{5}{8}$ in. |
| 2 20 in. | 5 7-in. liner or long-string |
| 3 $13 \frac{3}{8}$ in. | |

Figure 4—Normal-clearance Deepwater Casing Schematic with 30-in. Structural Casing



NOTE 1 Black is casing, grey is liner and white is annulus.

NOTE 2 Drawing to scale.

Key = OD

1 36 in.	4 18 in.	7 11 ⁷ / ₈ -in. liner
2 28 in.	5 16 in.	8 9 ⁷ / ₈ -in. tieback/liner/long-string
3 22 in.	6 13 ⁵ / ₈ in.	9 7 ³ / ₄ -in. liner

Figure 5—Tight-clearance/Long-string Intermediate Casing Schematic with 36-in. Structural Casing

5.2.2.2 Tight-clearance/Long-string Intermediate Casing

This design employs a large diameter intermediate casing string suspended and sealed at the wellhead with one or more intermediate liners hung below the casing string. The large diameter intermediate casing landed in the wellhead permits more liners below it while having sufficient load ratings to drill to TD. This architecture satisfies the need for additional shoe integrity. The larger and stronger intermediate casing minimizes the equivalent circulating density (ECD) by allowing subsequent strings to be run as liners instead of long-strings. This design is the most common and can result in high axial loads when running the intermediate casing string. It can result in increased APB for the “B” annulus if the long-string is a tieback or if the “B” annulus becomes plugged over time.

5.2.2.3 Tight-clearance/Heavy-wall Surface Casing

This design employs a heavy-wall, high-strength extension within the surface casing immediately below the HPWHH. The high pressure supplemental casing hanger adapter is installed in the heavy-wall, high-strength surface casing above the thinner wall surface casing. This design allows hanging of a casing (e.g. 16 in.) without using a hanger position in the HPWHH.

Benefits of the design are the following:

- lower ECDs due to greater clearances;
- can simplify plug and abandonment operations if supplemental casing hanger is set deeper in the well;
- allows larger diameter tiebacks due to the increased internal diameter of the heavy-wall surface casing;
- reduces the number of annuli at the wellhead that can affect the APB design;
- changes the “B” annulus by removing the intermediate long-string casing from the wellhead by replacing it with a liner (eliminates the normal “B” annulus).

This design exposes fabrication welds between the HPWHH and the supplemental adapter to the pressures and temperatures at TD, or until casing is run/tied back in the HPWHH.

Table 2 lists and describes typical casing types.

NOTE Production casing or tiebacks may be run as tapered strings if required to accommodate large diameter SCSSVs.

5.2.3 Completion Architecture

The objective of the completion architecture is to achieve the desired production or injection rates over the life of the well. This completion architecture forms the basis for selecting the production casing size.

These items can affect the design of the completion architecture:

- tubing size to achieve the desired well inflow/injection rate;
- sandface completion design;
- size of upper completion components (i.e. SCSSV, inflow control devices, injection subs);
- recompletion and fishability of completion components;
- control lines and chemical injection lines;
- artificial lift design;
- flow assurance requirements.

NOTE Refer to Section 9 for special considerations for completions.

Table 2—Typical Casing Types and Description

Casing	Description	Normal Clearance Casing OD in.	Tight Clearance Casing OD in.
Structural	Large OD casing; jetted in or drilled and cemented	30	36
Conductor	Additional casing run below structural casing (i.e. for shallow flow risks)	26	28 or 26
Surface	Casing including HPWHH (first casing string attached to subsea BOPs)	20	22
Shallow Intermediate Liner	Large diameter casing normally run as a liner and hung in a profile in the surface casing (18 in. can be called “surface extension” by regulators)	N/A	18 and/or 16
Intermediate Casing	Long casing string (12 1/4 in. drift, sizes range 13 3/8 in. to 14 in.) with casing hanger in the subsea wellhead housing	13 3/8	13 5/8
Intermediate Liner	Liner hung below intermediate casing/liner	N/A	13 5/8 or 11 7/8
Drilling Tieback	Casing run from top of liner to the subsea wellhead housing (i.e. for increased pressure capacity and/or casing wear considerations)	N/A	13 5/8 optional
Production Casing	Full string of production casing from below the objective interval with casing hanger in the subsea wellhead housing	9 5/8	N/A
Production Liner	Production casing run from below the objective section and hung in the intermediate casing or intermediate liner	N/A	9 7/8
Production Tieback	Production casing run from top of the production liner to the subsea wellhead housing NOTE The production liner tieback should have sufficient internal diameter to accommodate the surface controlled subsurface safety valve (SCSSV) and any control or chemical injection lines required for the completion.	N/A	10 3/4 × 9 7/8
NOTE These are examples only. Each well can have variations in number of casing strings and sizes. Naming conventions can vary. The heavy-wall surface casing designs may allow 13 5/8 in. to be run as a liner and not tied back.			

5.2.4 Production String Configurations

5.2.4.1 General

There are a number of issues to consider when selecting either a production liner, production liner tieback, or a long-string alternative for the production casing string. The effect of the configuration chosen on the total system reliability will depend on the specifics of the well. In some situations one design can provide a higher long-term reliability than another. The solution chosen should account for the anticipated pressures and combined loads while managing operational and life cycle risks.

5.2.4.2 Production Liner and Tieback Considerations

A production liner with a tieback may be considered for gas prone intervals experiencing severe lost circulation or intervals where hole conditions (obstructions or pipe sticking problems) can prevent the casing hanger from landing in the wellhead. A liner option allows use of a liner top packer (LTP), which

may be set after cementing. The LTP provides a mechanical barrier that isolates the open-hole section after it is set. Pressure testing a LTP does not confirm zonal isolation by the cement.

The liner option allows the casing to be hung at any depth if the string does not reach bottom. It also enhances well control by increasing the time during which the pipe rams can be closed on the drill pipe running string during liner installation.

The liner hanger system should be selected based on the expected pressures and combined loads. Close tolerance liner hangers (e.g. $13 \frac{5}{8} \times 11 \frac{7}{8}$ and $11 \frac{7}{8} \times 9 \frac{5}{8}$) can have reduced burst and collapse ratings when compared to the high-strength tubulars used in many liners. If increased pressure ratings are required, consideration can be given to hanging the liner in the next larger string or to other alternatives (e.g. tieback receptacle placed below hanger to increase system rating).

Additionally, the ability to execute a successful cement job and obtain adequate isolation should be considered. Depending on well conditions and equipment, liners may be rotated or reciprocated during cementing, which can increase mud-to-cement displacement efficiency in the annulus. The shorter annulus section (open hole remains the same but the cased hole section is reduced with a liner), combined with the concern for bringing cement above the liner, typically results in less cement volume being pumped versus a long-string option, unless the planned TOC for the long-string is reduced by APB considerations. Less cement volume could increase the potential for cement contamination. Refer to API 65-2 for additional cementing considerations.

Liner hanger geometries create annular restrictions with reduced flow by areas that can result in annular flow paths that yield higher or lower frictional pressures (compared to long-strings) when circulating. Depending upon liner hanger and well geometry, a liner configuration could have a lower ECD, which can increase the probability of obtaining a successful cement job. The liner configuration can provide more opportunities for barrier replacement in the event of a cement job that does not meet expectations. Refer to 5.3.4.5 and B.3 for information on verification of annular cement barriers. A liner configuration can provide additional annular barriers (i.e. installation and verification of a LTP or cemented tieback string).

Well designs that include production liners may require a production tieback to accommodate the producing pressures and combined loads. The addition of a production tieback increases the complexity of the well construction and the following should be considered:

- the tieback stem and liner polished bore receptacle (PBR) interface design;
- installation space-out to engage the tieback stem seals when the casing hanger is landed in the wellhead;
- tieback anchoring method to limit seal movement during the well's life cycle;
- an additional trapped annulus subject to APB loads.

5.2.4.3 Long-string Considerations

When using a long-string for the production casing, the following aspects of the casing annulus barrier plan should be considered:

- a) two verifiable physical barriers (i.e. annular cement and the casing hanger seal);
- b) addition of supplemental annular barriers (e.g. swellable packers or inflatable packers in the annulus);
- c) slurry design, placement, and verification;
- d) short transition times, anti-gas migration properties, fluid loss, rheology;

- e) lost circulation during cementing from ECD due to long, small annular clearances;
- f) can limit displacement rates with the potential for poor displacement efficiency;
- g) wells that experience losses or have poor mud/cement displacement efficiency during cementing can require increased levels of evaluation to confirm the cement barrier (refer to Table B.3);
- h) primary cement barrier quality;
- i) potential for annular gas migration resulting in additional casing and wellhead loads;
- j) the effect of thermal cooling of the mud, which can change hydrostatic pressure prior to cement set;
- k) mitigation options (refer to Table B.3);
- l) casing hanger lockdown requirements (refer to 6.2.1);
- m) exposure time with nonshearable items across the BOP stack when selecting either a liner or long-string option. Refer to 8.2.3.1 for additional information.

In addition, the ability to execute a successful cement job to obtain isolation should be considered. Depending on well conditions and equipment, liners may be rotated or reciprocated during cementing, which can increase mud-to-cement displacement efficiency in the annulus. To ensure proper space out, long-strings are usually landed in the wellhead housing prior to cementing; therefore, the lack of pipe movement reduces the mud-to-cement displacement efficiency in the annulus. Furthermore, as a result of long and tight annular clearances, additional ECD can be experienced, further complicating the cement job.

Refer to API 65-2 for additional cementing considerations. Refer to 5.3.4.5 and Annex B for information on verification of annular cement barriers.

5.3 Barrier Philosophy

5.3.1 General

This section describes how physical barriers and operational barriers contribute to well system reliability with respect to well control. It describes the principles, processes, and procedures for planning and implementing barriers. In this RP, barriers are defined as components or practices that contribute to the total system reliability to prevent or stop formation fluid or gas flow.

Apply the barrier philosophy to each potential flow path, while bearing in mind the consequences of a loss of well control. Follow local regulations related to barrier implementation.

5.3.2 Barrier Functionality

A petroleum well is a pathway through subsurface formations to a reservoir target that potentially contains hydrocarbons. As the well is constructed, barriers are installed to prevent flow from these formations from taking undesired paths (either to the surface or within the well). If a commercial quantity of hydrocarbons is discovered, final casing is set and a completion is installed to reliably contain the desired flow of production to the surface while the barriers prevent flow from taking undesired paths.

A system of multiple barriers is used to achieve a high level of reliability. The historical reliability of subsea well operations confirms that the philosophy of multiple barriers is effective. The well reliability is achieved through the combination of the individual barriers as a system and is not the result of the infallibility of a single component.

The designer's objective is to achieve a high level of well reliability by combining operational and physical barriers. Physical barriers contribute to a high level of reliability. Operational barriers depend on human recognition and response; however, when combined with properly designed, installed, and tested physical barriers, operational barriers significantly increase well reliability. Operational barriers also include institutional controls such as casing design standards and policy manuals.

The reliability of any physical barrier is increased if its integrity is tested to anticipated loads (i.e. in the direction of flow), after the barrier is deployed. Sometimes testing cannot be used to verify barrier integrity because potential load directions or anticipated loads cannot be simulated within the well. In these situations, more emphasis is placed on maximizing the reliability of the barrier by increasing quality control (QC) during design, manufacturing, and installation. If a barrier cannot be tested, its placement should be confirmed to the degree possible. Additionally, operational barriers are used to provide assurance that any failure of a physical barrier is detected early and managed without loss of well control.

Physical barriers (properly designed, installed and tested) contribute the most to the well reliability because of their very low failure rates. Operational barriers also increase the reliability of the well system. They become particularly important when the physical barrier system cannot be tested.

General recommendations that may be considered by the well designer and operations personnel are as follows.

- a) Assume that any single well barrier can fail, even those that are verified. The potential consequences of failure of each well barrier should be considered, and the required contingencies and responses should be identified.
- b) Understand which operational barriers should be actively in place when the rig is working on the well, regardless of the number of physical barriers in place or whether the barriers have been verified.
- c) If a physical barrier cannot be verified by testing it to its full anticipated loads, one of the following alternative verification methods should be considered:
 - test the barrier to a lower load or in the opposite direction of the maximum design load;
 - collect data or observations during physical barrier installation that confirm effective execution of the installation;
 - perform postinstallation inspection of the mechanical barrier;
 - if placement of a physical barrier cannot be confirmed, additional operational barriers may be used to enhance the well system reliability in accordance with local regulations. To enhance their effectiveness, operational barriers may be assessed with measurement, training and drills.
- d) Review the barrier plan as part of a management of change (MOC) process if well conditions change.
- e) Train personnel to understand that a decision not to deploy a planned operational or a physical barrier due to unexpected conditions can increase the likelihood of well system failure.
- f) If a physical barrier is found to be deficient during the course of operations and it cannot be repaired, reassess the remaining well system reliability in accordance with regulations. The loss of a physical barrier can cause a significant reduction in the well reliability. As a part of the MOC process, replacing the physical barrier (if possible), installing supplemental physical barriers, or using operational barriers should be considered.

5.3.3 Barrier Planning

A barrier plan should be developed that identifies flow paths and the barriers that prevent flow along each path, during each phase of the well construction process. Well diagrams illustrating the barriers in place for each operational phase should be included. Barrier planning includes determining the operating conditions to which various well barriers will be subjected over its intended lifetime and ensuring that the performance rating of the chosen barrier system is suitable for that well environment. This includes multiaxial loads and environmental conditions during routine conditions, as well as planning for any extreme operating conditions.

The barriers in a well change continually during the well construction process. The drilling process is a sequence of steps that expose formations to the wellbore. While drilling, the hydrostatic pressure of the drilling fluid is used to prevent flow until the exposed formations can be isolated with casing, cement, and other physical barriers. To drill deeper, the casing shoe track is drilled out (intentionally disabling a potential barrier). The drilling fluid column then provides a well control barrier while drilling the next hole section.

After the final casing is set and cemented, barriers are installed and verified to contain the completion flow path for long-term production or injection. A variety of short-term barriers are employed during the completion, with availability based on the specific operation performed. Upon completion, the well is designed to have multiple physical barriers against each potential flow path from the formations.

The number and types of well barriers used varies with the specific operation and may be specified by the governing regulatory body. It is generally accepted that using two physical barriers provides high system reliability. If an operation is performed with fewer than two physical barriers in place, then operational barriers become critical. For example, while drilling in open hole, the hydrostatic barrier of the drilling fluid is the only physical barrier preventing flow to the rig floor. The BOP equipment becomes a second physical barrier when it is closed and sealed.

The reliability of the BOP equipment as a physical barrier depends on operational barriers:

- detecting an influx at the rig,
- recognizing the need to respond,
- responding appropriately, and
- the proper design and functioning of the actuation system to close the sealing elements and valves.

Another common operation requiring extra focus on operational barriers is the removal of a physical barrier from the well. Examples of these operations include drilling out a cement plug or displacing the marine riser to seawater. It is essential that the rig crew understand that operational procedures are a critical part of the total well reliability and that practices for these critical operations should be designed, documented and tested in a manner similar to physical barriers. Whenever a physical barrier is to be disabled, it is important that field personnel understand the implications on safety and well integrity. The crew shall proceed under the assumption that the well could flow when that barrier is removed and be prepared to quickly react to any indication of flow. Refer to 8.2.2 for more information about displacements.

Permanent or temporary abandonment operations (involving the removal of the BOP stack, LMRP, and marine drilling riser), may be performed at the end of the drilling phase. This will result in the loss of at least one and possibly two physical barriers (the ability to have a closed BOP and the hydrostatic barrier if the fluid density does not include riser margin). When a well is unattended, operational barriers are not available to contribute to overall system reliability. All planned physical barriers should thus be in place and verified. At least two verified physical barriers (one mechanical, and one may be a cement barrier) are required in DW wells for abandonment. At least one of the abandonment barriers should be tested.

Local regulations will determine testing and documentation requirements. Refer to Table A.3 for abandonment examples.

Consider placing the deepest barrier (inside the casing) as close as practical above the reservoirs or potential sources of leaks. A barrier placed farther up-hole from the pressure source may have lower reliability due to the number of connections exposed below it. Consider placing this barrier in a cemented part of the casing to enhance the system reliability by lowering the chance of an alternative pathway around the barrier through a connection leak below it, and up the annulus. When temporarily abandoning the well for later reentry, a barrier placed deep in the well near the pressure source minimizes the potential for formation fluids (particularly gas) to build up pressure below the barrier.

During ongoing production operations, operational barriers include monitoring the tubing-by-production casing annulus pressure or monitoring changes in production conditions that could signal a change in the well status, with a resulting impact on overall well integrity.

Annex A provides examples of common operational scenarios and lists common well barriers associated with each flow path. Annex B provides examples of common barriers and considerations associated with implementing them in the well design for operational scenarios described in Annex A. The format of tables, well schematics and descriptions of various flow paths are suggested as a template for communicating a barrier plan for a well operation.

NOTE The lists of scenarios and well barriers in the annexes are not comprehensive.

5.3.4 Barrier Verification

5.3.4.1 General

Acceptance criteria shall be established for each barrier. The levels of acceptance may result in classification of the barrier as being verified, either as a tested or a confirmed barrier, as defined in this document. Acceptance criteria define the conditions to be fulfilled to verify the integrity of the barrier for its expected application. Sometimes it is feasible to directly verify that the barrier is preventing flow by pressure testing, or barrier performance may be verified through other observations. Barrier verification results shall be documented and retained as required by local regulations or by company policy.

5.3.4.2 Integrity of Physical Barriers

5.3.4.2.1 General

Integrity of physical barriers involves the phases described in 5.3.4.2.2 through 5.3.4.2.6.

5.3.4.2.2 Design

The well designer determines the physical loads, planned operating conditions, and environmental conditions that a physical barrier may be exposed to during the life of the barrier. These predicted conditions define the functional requirements for the equipment and material selection. The well designer compares these functional requirements to capacity or operating rating of the equipment defined by the technical specifications obtained from the manufacturer or industry standards.

The well designer or manufacturer may elect to confirm the capacity of the equipment through qualification. Equipment qualification methods may include finite element analysis and/or physical testing. Additional qualifications may be needed to ensure the equipment satisfies the functional requirements of the well application.

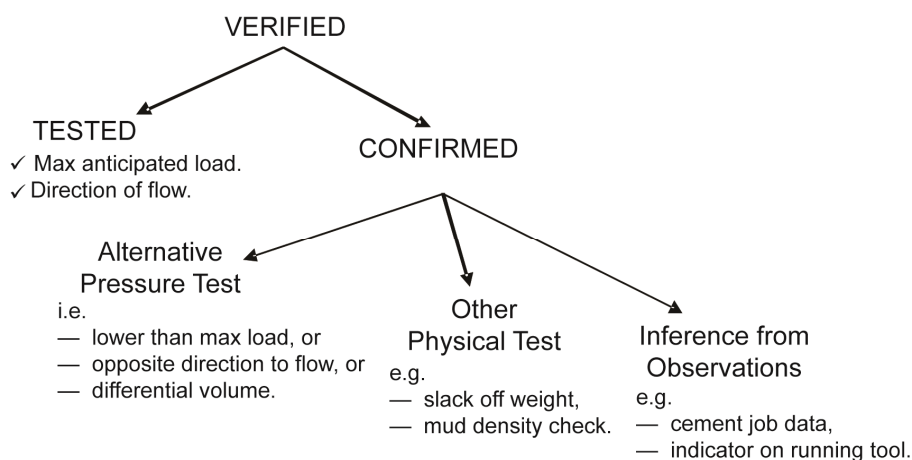


Figure 6—Representation of Barrier Verification Categories

5.3.4.2.3 Manufacture

The manufactured equipment should meet its technical specifications. These specifications typically include the following:

- material requirements for each component;
- tolerances;
- assembly and processing steps;
- quality and inspection plan.

Full or partial component testing of the equipment may also be necessary for the application. Depending on the type of equipment and the type of well, the technical requirements may be defined by the manufacturer, by an industry standard, or may be determined by agreement between the manufacturer and purchaser.

NOTE For some well barriers, (i.e. cement mixing) final manufacture is performed at the rig site.

5.3.4.2.4 Installation in the Well

The barrier shall be installed according to documented procedures or field practice. Data collection during installation may be necessary to verify the barrier. In this case, the installation procedures specify the required data collection and acceptance criteria.

5.3.4.2.5 Pressure Testing or Verification After the Installation is Complete

A pressure load can be applied to the barrier to evaluate its proper installation and to simulate an anticipated operational condition. It is not feasible to pressure test some barriers, particularly those placed in an annulus. Only the placement of these barriers can be confirmed (e.g. record observations during placement and compare to prejob expectations to demonstrate successful placement or use alternate methods such as logging tools).

5.3.4.2.6 Operation

During continuing well operations, the ongoing effectiveness of some barriers may be monitored or reassessed. In some cases, the absence of pressure indicates that well control is maintained. While in other cases, an initial test can be repeated or an alternate test applied.

5.3.4.3 Verification by Pressure Testing

5.3.4.3.1 General

The most reliable verification of a physical barrier is to pressure test to the expected differential pressure in the direction of flow after the barrier is installed in the well.

It is practical to pressure test a newly installed mechanical barrier using the fluid that is in the well at the time of the installation. This fluid is typically the drilling mud, completion brine or water. Often regulations dictate the acceptance criteria for a pressure integrity test. Acceptance criteria (established by the well designer) may include:

- a pressure change during hold time;
- a visual observation of leak;
- a difference between pressure-up volume and bleed-back volume;
- a visual observation of fluid level.

NOTE It is good practice to conduct a low-pressure test (~200 psi or 300 psi) before a high-pressure test on mechanical components whose design allows their seal elements to be energized by the application of pressure.

5.3.4.3.2 Inflow Testing

An inflow test involves assessing integrity of a barrier system in the direction of flow from the formation into the wellbore. This typically involves replacing the hydrostatic barrier above the physical barrier to be inflow tested with a lighter hydrostatic fluid column and an operational barrier such as a BOP or test tool. This creates a managed net pressure load against the physical barrier in the direction of flow from the subsurface formations into the well. This can be accomplished by displacing some of the kill-weight fluid out from the well with lower density fluid(s). Refer to Annex C for examples of inflow testing scenarios.

To limit the quantity of kill-weight fluid displaced from the well and to create a trapped volume to test, the low density fluids are often displaced down a drill string and trapped by a temporary mechanical test barrier (e.g. packer, wellhead test plug, closed test rams, etc.) set above the physical barrier being tested. The temporary mechanical test barrier may serve as an additional well control barrier to replace the loss of the hydrostatic barrier during the inflow test. The ratings of all of the barriers (including the temporary mechanical test barrier) that will be exposed to the inflow net pressure during the inflow test should be considered.

In addition, the method by which the hydrostatic barrier will be reestablished at the conclusion of the inflow test, or in the event an anomaly is detected during the inflow test, should be considered. A contingency plan for reestablishing appropriate barriers should be prepared in case the barrier being tested does not pass the inflow test.

5.3.4.3.3 Alternatives to Inflow Testing

The verification method of conducting a full-differential pressure test in the direction of flow is not always feasible. The well designer may consider verifying the barrier using other physical evaluation methods.

Barriers that are verified by methods other than a pressure test in the direction of flow are categorized as “confirmed.” Inflow testing alternatives may include the following.

- Pressure test in the direction opposite of flow (if appropriate for the barrier).
- Select a test pressure so that part of the barrier is exposed to the desired maximum pressure differential (also applies to a tubular string integrity test where the pressure load varies considerably over the length of the string).
- Once a deep barrier has been verified by pressure testing, subsequent shallow barriers cannot be directly verified by holding a test pressure. In place of a stabilized test pressure, the total system pressure versus volume response can be used to verify a shallow barrier. Thus to verify subsequent barriers set shallower in the well, compare the volume required to be pumped to reach the test pressure for the deeper barrier to that when testing the shallower barrier. The volume required should decrease due to less volume of fluid being compressed.
- Slack-off weight of string on a cement plug in a tubular to confirm that the plug has set or hardened as designed (acceptance criteria may involve applied weight and/or permitted penetration depth). This evaluation method will confirm that cement has set but not that it is a barrier to fluid flow.
- Perform a drilling test of a cement plug by assessing the cement strength by the (high) weight on bit needed to drill the plug, or by the (slow) rate of penetration while drilling it, as a qualitative assessment of the cement barrier. The size of the cement plug may be increased to accommodate the length lost while performing the drilling test.

5.3.4.4 Verification of Hydrostatic Barriers

For a fluid column to serve as a barrier, the hydrostatic pressure of the fluid must exceed the pore pressure of the formation on which the pressure acts. Hydrostatic pressure is the pressure exerted by a fluid due to the vertical height and density of the fluid column. This requires a continuous fluid column of sufficient height to exceed the pore pressure. Failure to maintain the fluid column height may cause a pressure underbalance and allow the formation to flow.

Measure the density of the fluid and make adjustments, as necessary, to maintain the overbalance. The temperature profile of the well and the impact of temperature on fluid density should be considered. Pressure changes due to the dynamic effects of fluid movement arising from circulation or pipe movement should be considered. Further, where solids-laden fluids are used as hydrostatic barriers under static conditions, evaluate the effects of hole geometry (e.g. deviation, hole size, etc.) and exposure time on barrier effectiveness.

The drilling mud hydrostatic pressure from the height of the marine riser can be suddenly replaced with seawater hydrostatic pressure in an event where the LMRP is disconnected (i.e. a drift-off or drive-off scenario). This scenario can result in losing hydrostatic pressure (sufficient to maintain a barrier to the formation pressure). Thus, operational barriers must be in place to provide assurance that another physical barrier is rapidly established. For dynamically positioned rigs, an EDS is programmed to actuate the BOP and seal the wellbore with the BSRs when activated by the driller. In certain wells, a mud density can be used that maintains an overbalanced condition (even in the LMRP disconnection scenario). Refer to 8.2.2.1 for more information on riser margin.

NOTE If a fluid column contains some length of unset cement, any fluid below the top of cement (TOC) may lose pressure communication with the hydrostatic of the fluid above as the cement transitions from a liquid to a solid. The pressure exerted by a fluid volume that is located below a cement barrier can be more difficult to determine.

5.3.4.5 Verification of Annular Cement Barrier

For set cement in the annulus to serve as a physical barrier to the influx of formation fluids, the cement slurry shall be designed and laboratory-tested for the anticipated well conditions. The cement slurry should be placed in the well using recommended practices and equipment in accordance with API 65-2.

Successful placement of properly designed cement slurry can create a reliable annular barrier. However, verification of this barrier cannot be achieved through testing. Rather, it is confirmed using data collected during the slurry placement operation. If the data indicates that the cement top may not be at the planned depth or that the slurry placement has other problems, a diagnostic log may be used to establish the location of the cement top and/or evaluate the bond quality. Local regulations may specify alternative acceptance criteria or evaluation steps.

Exercise caution when using cement evaluation logs as the primary means of establishing the hydraulic competency of a cement barrier. The interpretation of cement evaluation logs is subjective. Refer to API 10TR-1 for an overview of the attenuation physics, features, and limitations of the various types of cement evaluation logs.

5.3.4.6 Assessment of Operational Barriers

Operational barriers include continuous monitoring of the well system, rapid recognition of evidence of an integrity upset, and effective execution of mitigation plans. By their nature, operational barriers cannot be tested like physical barriers. Testing shall be done to help assure that a physical barrier can be actuated when needed. Such tests include function testing on a periodic basis.

It is possible to certify personnel who have completed well control training, assign responsibilities for responding to a well control event, conduct drills to demonstrate readiness and proficiency, and retain records that demonstrate successful execution of institutional controls. Examples include well control certificates and records of operational drills.

5.3.5 Barrier Maintenance

Because any physical barrier can fail, the ongoing effectiveness of barriers is often assessed. The act of reassessing barrier performance is an operational barrier. Detection of a barrier failure normally results in immediate action to address the failure before continuing planned operations.

A retest of a physical barrier is the highest level of verification of the ongoing effectiveness of the barrier. Regulations often dictate the required retest frequency of equipment. The effectiveness of some barrier systems under operating conditions can be checked by inspection. An example of checking a barrier with in situ inspection is using a caliper log to measure the casing wall thickness (depending on tool type, this may be inferred from measuring casing internal diameter with a known outside diameter).

If a barrier fails, then reconsider the integrity of the overall well system, before continuing the current operation. Refer to local regulations for remedial actions for barrier failure. The following alternatives should be considered:

- attempt to restore the barrier (i.e. repair/replace casing or hanger, repair BOPs, etc.);
- install a different barrier (may be another barrier of the same type or a different type);
- reconsider the overall system reliability based on the well's forward plan;
- create additional operational barriers.

The tables in Annex B provide examples of barrier assurance and barrier reestablishment if failure of a physical barrier occurs.

5.4 Load Cases—Drilling and Completion Conditions

5.4.1 Tubular and Equipment Design Methodology

This section describes a common approach to how the well designer determines if a particular tubular string or hardware component (i.e. liner hanger, casing hanger, seal assembly, PBR, wellhead, BOP, float equipment, etc.) satisfies the requirements of the well application. The fundamental processes are similar for both casing and hardware components. Individual company designs can account for different loads and resistance by having varying inspection programs, operational limits, and practices. All processes are based on the tubular string design premise that the capacity exceeds expected loads. Each string builds on the previous, either isolating it from the internal load (long-string) or extending it (e.g. liner). The entire system shall be evaluated during well design to ensure a reliable, fit-for-purpose design.

The fundamental approach is to determine the following:

- a) Determine the loads and the environment that the tubular string or component will experience throughout the well's life.

NOTE The magnitude of the loads can vary during different stages of well construction and operation.

EXAMPLE Pressure loads on the casing and hardware are typically low during well construction. However, during production operations, the tubing and other completion components routinely sustain higher continuous pressure loads.

- b) Establish the capacity of the tubular or component in the loading direction and its suitability under the environmental conditions (refer to 5.4.3).
- c) Compare the loads to the capacities at the expected environmental conditions. The tubular or component is judged to be acceptable for the application if its capacity exceeds the anticipated load by an appropriate margin (design factor).

5.4.2 Loads

5.4.2.1 General

An operator designs a well for a given set of load conditions. Design load cases are based on individual company design standards, government regulations, component design and reliability considerations, local experience or field specific rules, operational considerations, and other factors. The internal loads are calculated and combined with the external loads to get the effective loads. The effective loads are compared with tubular or equipment ratings to ensure that the required design factors are met for their application. The design factor approach is used for well design because it is efficient and produces results with proven reliability.

To design casing, tubing, hardware and completion components, the well designer should use loads that represent expected load scenarios. Refer to Table 3 for examples of internal loads. During well construction, the design loads are short-duration and fit-for-purpose (e.g. partial well evacuation for collapse, deterministic kick volume for burst). During production operations, expected loads are of longer duration and expected (e.g. burst based on shut-in pressures, collapse based on depletion loads due to artificial lift, thermal loading during production or treating).

5.4.2.2 Internal Loads—MASP and MAWHP Determination

Maximum anticipated surface pressure (MASP) is a design load that represents the maximum internal pressure that may occur at the surface within each hole interval during the construction of the well. The internal pressure is typically defined by either an applied pressure or a reservoir pressure (subtracting the hydrostatic fluid/gas column). Examples of the methodology used to calculate MASP are shown in Table 3.

For DW wells, the maximum internal pressure at the subsea wellhead is called the maximum anticipated wellhead pressure (MAWHP). MAWHP for a DW well would be defined as the subsea wellhead pressure under MASP conditions. MASP and MAWHP vary only by the internal fluid/gas hydrostatic head pressure from the wellhead to the surface. The MAWHP is an internal pressure, and does not account for the effect of the external seawater gradient down to the wellhead.

This document only presents examples and leaves actual load case selection and definition to the operators. For example, MASP calculation methods (include, but are not limited to) the load cases described in Table 3.

5.4.2.3 External Loads

The pressure gradient that exists in the annulus behind each casing string depends on a variety of factors, and it can vary over the life cycle of the well. Immediately following cementing operations, the gradients are those of the drilling fluid, cement spacers, and liquid cement. However, complex changes can occur as the cement sets and the mud degrades. These changes should be considered in estimating the long-term backup resistance. The external pressure at the wellhead is based on a seawater gradient for DW wells.

Because of uncertainty in the annular pressure gradient over extended times (particularly within the cement column), assumptions may be made that represent a conservative case. Some time-dependent assumptions include the gradient of the drilling fluid above the TOC, which can partially degenerate (due to settling of the weight material) over time. The settling tendency of the weight material depends on fluid type, rheological properties, weight material characteristics and well conditions (i.e. temperature, geometry), and can be difficult to predict. In an open hole, the amount of gradient reduction is limited by the pore pressure. In a closed casing-by-casing annulus, the fluid gradient in the uppermost portion of the well can approach that of the base fluid.

For collapse design, use of the original mud gradient behind the casing should be considered (rather than using a partly or fully deteriorated mud gradient behind the casing) to avoid under-estimating the driving external collapse pressure.

The effective gradient in cement (assuming it is semiplastic as it sets and is capable of transmitting pressure) in the open hole will equal the pore pressure of the adjacent formation.

Less is known about the burst design backup provided by set cement within a casing-by-casing annulus (cement in the casing overlap or behind a tieback). Once cement becomes a solid, it no longer transmits fluid pressure. However, when burst pressures are applied to the pipe, the solid cement provides a mechanical backup, and the net loads on the tubular may be lower. Various models are available to estimate the structural contribution of the cement to the tubular burst resistance. An alternative approach is to use the cement mix-water density to define the backup fluid gradient for burst design calculations.

NOTE The settled weighting material may create a barrier in the annulus, restricting APB pressure relief to an uncemented open-hole interval below the previous shoe.

Refer to API 65-2 for further details about cementing.

Advanced design considerations may investigate the effect of point loading on collapse (such as where uneven stresses are applied through reservoir compaction, an active fault or salt movement).

Table 3—Example Basis of MASP Internal Load Cases

Item	Internal Load Case	Description of Load Case
1	Combination of hydrocarbon/mud	Establish the hydrocarbon and mud gradients and their configuration in the well. Use a percentage of mud and percentage of hydrocarbons (these percentages may differ for shallow well depths versus deep strings).
		Use the highest bottomhole pressure (BHP) in the open-hole section and the gradients of the fluids to surface to determine the BHP-based MASP.
2	Fracture gradient at shoe and hydrocarbons to surface	Establish the hydrocarbon gradient.
		Base MASP on the fracture pressure at the deepest exposed shoe (or shoe with the highest fracture gradient and pressures) less the hydrostatic pressure of a column of hydrocarbons (gradient multiplied by true vertical depth) to surface.
3	Hydrocarbons to surface	Base MASP on reservoir BHP less the hydrostatic pressure of a column of hydrocarbon (gradient times true vertical depth) to surface.
		When determining production loads, the packer fluid's effect on casing loads for a shallow tubing leak should be considered.
4	Survival Loads	Refer to 5.4.5
5	Limited kick volume	Based on company design philosophy and regional experience, determine a given kick volume, intensity and hydrocarbon type.
		Perform modeling for circulating the kick out of the well to determine MASP and the internal pressure profile. Factors that affect the modeling include the following. — Kick models that assume the gas remains in a single bubble give higher values than those observed in the field. — Kick models that accurately handle a distributed gas bubble are complex, requiring multiphase flow calculations, and are normally not used in shallow well design or for oil reservoirs. — Gas going into solution in nonaqueous fluid (NAF) at high pressures also requires a complex model.
6	Completion or treating loads	Base MASP on bottomhole treating pressure less the head of the treating fluid (e.g. fracturing, frac and pac sand laden fluid) plus additional pressure margin to account for screenout conditions. The safety margin for bullheading operations should be considered. Pressure tests shall not exceed the maximum working pressure of any component. Refer to Section 7 for more information.
7	Injection Loads	Maximum predicted water/gas injection or gas lift pressure.
8	Internal pressure testing	Pressure test casing upon installation, which may simulate service loads.
		Understand that companies select their test pressure based on a combination of regulatory requirements, experience and the designed capacity of the system.

5.4.2.4 Survival Design Considerations

Survival design scenarios can include extreme cases such as the complete loss of well control (blowout) from a well and reestablishing well control by installing a capping BOP stack. Extreme load scenarios are unlikely; however, it may be appropriate to consider loads that arise from these scenarios and to determine if the tubulars and equipment can survive the conditions. The well designer may adopt a philosophy of using different criteria for failure and different design factors. Tubular failure without the loss of life or damage to the environment may be considered. An example could be the collapse of a deep liner which does not result in hydrocarbon release to the mudline.

A capping stack may be used either to limit the flow from a well or to completely shut in the flow. If a complete loss of well control situation occurs, the highest collapse loads occur before the capping stack is installed. A cap and flow approach reduces the burst loads as compared to shutting in the well.

The capping stack may be a single ram, full BOP stack or other valve configuration. The additional bending loads exerted by the capping stack on the wellhead and structural pipe should be considered.

When designing for regular kick loads, the design criteria might be defined as the onset of yield, using minimum material properties, minimum measured wall thickness, and a design factor approaching 1.0. Alternatively, when determining tubular survival capability under extreme load conditions, the design criterion might be based on rupture capacity such as in API 5C3, using actual material properties and/or operator design practices based on advanced design methods or physical testing. Evaluate the entire system, including liner hangers, connections, and wellheads. Formulas for rupture in a nonsour environment are contained in API 5C3. Appropriate pipe performance guidance in sour environments is provided in 6.13.

NOTE An assumption inherent in putting a load scenario into a “survival” category is that while the tubulars or equipment may survive the load, the normal operability may be compromised by exposure to the survival load. Reassess the suitability of the well for continuing operations after a survival load situation occurs.

Examples of loads that might arise from survival scenarios for DW wells include the following.

EXAMPLE 1 Collapse loads during unintended flow: low back-pressure at the discharge location (surface or mudline) enables high flow rates and a low internal pressure profile compared with a typical hydrostatic column of drilling or completion fluid. The high flow rates of fluids at the reservoir temperature heat the wellbore, causing the fluids in the annuli to expand and possibly create additional pressure in the annulus. The pressures in the annuli increase because of this expansion, and collapse loads are increased.

EXAMPLE 2 Burst loads following cap and shut in: drilling casing design has always considered that a kick load may occur, and production casing design always considered that the tubing may leak; however, the maximum expected load is based on normal well control operations. Installing and closing or choking a capping stack after unintended flow may subject the exposed tubulars and equipment in the well to a full column of the production fluid with reservoir pressure at the source. At the mudline, this is known as the mudline shut-in pressure. The resulting burst load scenario also includes a high temperature arising from the warm flow when the capping stack valves are initially closed and transitioning to the geothermal temperature when the flow is stopped and the heat dissipates. A combination of internal pressure and cool temperature increases the tension load on tubulars, particularly at the top of the well.

EXAMPLE 3 Axial forces; unconstrained flow will raise the wellbore temperature at the mudline which will reduce tension loads and possibly create compression loads and upward forces on the wellhead hangers. These compression loads should be addressed.