

Isolating Potential Flow Zones During Well Construction

API STANDARD 65—PART 2
SECOND EDITION, DECEMBER 2010

REAFFIRMED, NOVEMBER 2016



AMERICAN PETROLEUM INSTITUTE

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Upstream Segment

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Contents

Page

1	Scope	1
1.1	Overview	1
1.2	Objectives	1
1.3	Background and Technology Review	1
1.4	Conditions of Applicability	1
1.5	Well Planning and Drilling Plan Considerations	1
1.6	Drilling the Well	2
1.7	Summary of Considerations	2
2	Normative References	2
3	Definitions, and Abbreviated Terms	3
3.1	Definitions	3
3.2	Abbreviations	10
4	Barriers	11
4.1	General	11
4.2	Physical Barrier Elements	12
4.3	Hydrostatic Barrier Elements	12
4.4	Annular Mechanical Barrier Elements	12
4.5	Mechanical Wellbore Barrier Elements	15
4.6	Set Cement as a Barrier Element	16
5	Cementing Practices and Factors Affecting Cementing Success	18
5.1	Introduction	18
5.2	Hole Quality	18
5.3	Drilling Fluid	19
5.4	Casing Hardware	19
5.5	Close-tolerance and Other Flow Restriction Considerations	20
5.6	Engineering Design	20
5.7	Slurry Design and Testing	25
5.8	Wellbore preparation and conditioning	31
5.9	Cement Job Execution	33
5.10	Post Cementing Operations	37
6	Casing Shoe Testing	38
7	Post-cement Job Analysis and Evaluation	39
7.1	Material Inventory	39
7.2	Job Data	39
7.3	Cement Evaluation	39
	Annex A (informative) Background and Technology	40
	Annex B (informative) Well Planning and Drilling Plan Considerations	59
	Annex C (informative) Drilling the Well	68
	Annex D (normative) Process Summary: Isolating Potential Flow Zones During Well Construction	75
	Bibliography	81

Contents

Page

Figures

1	Sonic Strength Anomaly.	17
A.1	Effect of Curing Pressure on Bond Failure	42
A.2	Annular Pressure and Temperature—Well G	55
A.3	Annular Pressure and Temperature—Well B	56
A.4	Annular Pressure and Temperature—Well A	57
A.5	Mud Densities Measured By Pressure Sensors in Annulus.	58
B.1	Casing Shoe Depths with Pore Pressure/Fracture Gradient Graph	61

Tables

A.1	Most frequent Primary and Secondary Barriers that Failed in all Phases	45
A.2	Drilling and Service Well Control Occurrences, 1998/1999	46
A.3	Drilling and Service Well Control Occurrences, 2003.	47
A.4	Surface Casing Vent Flows	47
A.5	Gas Migration Problems.	47
A.6	Packer Isolation Testing and Reporting Program Results	47
A.7	Well Status at Time of the Incident	48
A.8	Blowouts by Well Type	49
A.9	Blowouts by Depth Category	49
A.10	1991 API Survey Data on Lost Circulation	51

Isolating Potential Flow Zones During Well Construction

1 Scope

1.1 Overview

This standard contains practices for isolating potential flow zones, an integral element in maintaining well integrity. The focus of this standard is the prevention of flow through or past barriers that are installed during well construction. Barriers that seal wellbore and formation pressures or flows may include mechanical barriers such as seals, cement, or hydrostatic head, or operational barriers such as flow detection practices. Operational barriers are practices that result in activation of a physical barrier. Though physical barriers may dominate, the total system reliability of a particular design is dependent on the existence of both types of barriers.

1.2 Objectives

The objectives of this guideline are two-fold. The first is to help prevent and/or control flows just prior to, during, and after primary cementing operations to install or “set” casing and liner pipe strings in wells. Some of these flows have caused loss of well control. They threaten the safety of personnel, the environment, and the drilling rigs themselves. The second objective is to help prevent sustained casing pressure (SCP), also a serious industry problem.

[API RP 90](#), provides guidelines on managing annular casing pressure (ACP) including SCP, thermal casing pressure, and operator-imposed pressure. These guidelines include monitoring, diagnostic testing, establishing the maximum allowable wellhead operating pressure (MAWOP), documenting annular casing pressure, and risk assessment methodologies.

1.3 Background and Technology Review

A detailed background and technology review are in Annex A. Historical data, perspectives, studies, statistics, lessons learned, etc. are included. All this information has been written to help explain how some practices work, have become proven or invalidated, or had performance limitations placed upon their application.

1.4 Conditions of Applicability

The process of barrier element selection and installation (including cement) is governed by the anticipated presence or absence of potential flow zones that require isolation for well integrity or regulatory purposes. This document applies only when it is deemed necessary that a potential flow zone be isolated. The guidance from this document covers recommendations for pressure-containment barrier (cement, packers, etc.) design and well construction practices that affect the zonal isolation process to prevent or mitigate annular fluid flow or pressure. These practices may also help prevent loss of well control (LWC) incidents and minimize the occurrence of SCP during well construction and production.

As presented earlier herein, the content of this document is not all inclusive and not intended to alleviate the need for detailed information found in textbooks, manuals, technical papers, or other documents. Included are those practices (well design, drilling, completion, etc.) that may positively or negatively affect pressure-containment barrier sealing performance along with methods to enhance the positive effects and to minimize any negative ones.

This document does not address shallow water flow zones in deepwater wells which are covered in [API RP 65](#).

1.5 Well Planning and Drilling Plan Considerations

Annex B includes consideration in well planning and drilling plan determinations, such as evaluation for flow potential, site selection, shallow hazards, deeper hazard contingency planning, well control planning for fluid influxes, planning

for lost circulation control, regulatory issues and communications plans, planning the well, pore pressure, fracture gradient, drilling fluid weight, casing plan, cementing plan, drilling plan, wellbore hydraulics, wellbore cleaning, barrier design, and contingency planning. These elements factor into the planning of the well to enhance the barrier sealing performance.

In some cases, pre-spud information gathered from offset well(s) and/or from high resolution seismic surveys can be used to indicate flow potential for a particular drilling prospect. Any relevant information should be communicated to the appropriate service provider for incorporation into the design for a particular fluid (drilling fluid or cement) and for preparing engineering and operations procedures.

1.6 Drilling the Well

Annex C gives a general overview of drilling the well and some of the factors that might be considered by the drilling group. Some of those factors may include general practices while drilling, monitoring and maintaining wellbore stability, mitigating lost circulation, and planning and operational considerations. There may be other factors to consider such as type and location of the well being drilled. These factors should be considered during the drilling of the well to enhance the barrier sealing performance. Detailed discussion of these factors is included in Annex C and may be mentioned in other sections.

1.7 Summary of Considerations

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

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

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

2 Normative References

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

[API Recommended Practice 10B-2/ISO 10426-2](#), *Recommended Practice for Testing Well Cements*

[API Recommended Practice 10B-3/ISO 10426-3](#), *Recommended Practice on Testing of Deepwater Well Cement Formulations*

[API Recommended Practice 10B-4/ISO 10426-4](#), *Recommended Practice on Preparation and Testing of Foamed Cement Slurries at Atmospheric Pressure*

[API Recommended Practice 10B-5/ISO 10426-5](#), *Recommended Practice on Determination of Shrinkage and Expansion of Well Cement Formulations at Atmospheric Pressure*

[API Recommended Practice 10B-6/ISO 10426-6](#), *Recommended Practice on Determining the Static Gel Strength of Cement Formulations*

[API Specification 10D/ISO 10427-1](#), *Specification for Bow-Spring Casing Centralizers*

API Specification 10D-2/ISO 10427-2, *Recommended Practice for Centralizer Placement and Stop Collar Testing*

[API Recommended Practice 10F](#)/ISO 10427-3, *Recommended Practice for Performance Testing of Cementing Float Equipment*

[API Technical Report 10TR1](#), *Cement Sheath Evaluation*

[API Technical Report 10TR3](#), *Temperatures for API Cement Operating Thickening Time Tests*

[API Technical Report 10TR4](#), *Technical Report on Considerations Regarding Selection of Centralizers for Primary Cementing Operations*

[API Technical Report 10TR5](#), *Technical Report on Methods for Testing of Solid and Rigid Centralizers*

[API Recommended Practice 13B-1](#)/ISO 10414-1, *Recommended Practice for Field Testing Water-Based Drilling Fluids*

[API Recommended Practice 13B-2](#)/ISO 10414-2, *Recommended Practice for Field Testing Oil-based Drilling Fluids*

[API Recommended Practice 53](#), *Blowout Prevention Equipment Systems for Drilling Operations*

[API Recommended Practice 65](#), *Cementing Shallow Water Flow Zones in Deep Water Wells*

[API Recommended Practice 90](#), *Annular Casing Pressure Management for Offshore Wells*

3 Definitions, and Abbreviated Terms

3.1 Definitions

For the purposes of this document the following terms and definitions apply. In addition to those listed below other definitions and abbreviations may be found in oilfield glossaries at websites listed in the Bibliography. [47,48,49,50,51]

3.1.1

ambient pressure

Pressure external to the wellhead. In the case of a surface wellhead it would be 0 psig. In the case of a subsea well head, it would be equal to the hydrostatic pressure of seawater at the depth of the subsea wellhead in psig.

3.1.2

annular flow

The flow of formation fluids (liquids and/or gases) from the formation into a space or pathway in an annulus within a well. The annular flow may follow various flow paths inside the annulus to other points including those at shallower or deeper depths.

3.1.3

annular packers and seal rings

Mechanical barrier devices with flexible, elastomeric sealing elements that can be run into a well on casing or liners for application as:

- a) annular element installed between an inner and outer pipe or between a casing and openhole formation to seal the annulus,
- b) annular seal rings installed on the inner pipe string to seal the micro-annulus and voids formed between the cement sheath and the inner pipe string.

3.1.4**annular pressure buildup****APB**

Pressure generated within a sealed annulus by thermal expansion of trapped wellbore fluids typically during production. May also occur during drilling operations when trapped annular fluids at cool shallow depths are exposed to high temperatures from fluids circulating in deep, hot hole sections. This thermally induced pressure is defined and listed in [API RP 90](#) as thermal casing pressure. APB is also referred to as annular fluid expansion (AFE).

3.1.5**annuli**

Plural of annulus. A well may contain several annuli formed by multiple casing and liner pipe strings.

3.1.6**annulus**

The space between the borehole and tubulars or between tubulars, where fluid can flow. The annulus designation between the production tubing and production casing is the "A" annulus. Outer annuli between other strings are designated B, C, D, etc. as the pipe sizes increase in diameter.

3.1.7**barrier (barrier element)**

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

3.1.8**blowout preventer****BOP**

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

3.1.9**borehole**

Wellbore sections which are not cased with pipe, commonly called open hole.

3.1.10**bottom hole assembly****BHA**

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

3.1.11**cased hole**

The wellbore intervals in a well that are cased with casing and/or liner pipe. The diameter of these hole sections is the inside diameter of the pipe contained therein.

3.1.12**completion string**

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

3.1.13**conductor casing**

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

3.1.14**critical gel strength period****CGSP**

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

3.1.15**critical static gel strength****CSGS**

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

3.1.16**diverter**

A device connected to the top of the wellhead or marine riser, directing flow away from the rig.

3.1.17**riser**

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

3.1.18**drive/jet pipe**

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

3.1.19**equivalent circulating density****ECD**

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

3.1.20**external casing packer****ECP**

An external casing packer is a mechanical annular barrier that has elastomeric elements that seal the annulus when inflated. Also see the definition in this section for annular packers and the description of an ECP in 4.4.

3.1.21**fixed platform wells**

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

3.1.22**formation fluids**

Fluids present within the pores, fractures, faults, vugs, caverns, or any other spaces of formations are called formation fluids whether or not they were naturally formed or injected therein. The physical state of formation fluids

may be liquids or gases and include various types such as hydrocarbons, fresh or saline water, carbon dioxide, hydrogen sulfide, etc.

3.1.23

formation integrity test

FIT

Formation integrity test is similar to a leak-off test (LOT) except that fracture initiation pressure is not exceeded. See definition of leak-off tests.

3.1.24

fracture gradient

FG

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

3.1.25

hybrid wells

Wells drilled with a subsea wellhead and completed with a surface casing head, a surface tubing head, a surface tubing hanger and a surface tree.

3.1.26

intermediate casing

Casing that is set when geological characteristics or wellbore conditions require isolation. These conditions include, but are not limited to, prevention of lost circulation, formation fluid influx or hole instability. Multiple intermediate casing strings can be run in a single well.

3.1.27

leak-off test

LOT

A leak-off test is a procedure used to determine the wellbore pressure required to initiate a fracture in the open or exposed formations.

3.1.28

liner

A liner is a casing string that does not extend to the top of the well or to the wellhead. Liners are anchored or suspended from inside the previous casing string using a liner hanger. The liner can be fitted with special components so that it can be connected or tied back to the surface at a later time.

3.1.29

liner hanger

A device used to attach or hang a liner from the internal wall of a previously set casing string. Conventional liner hangers are "hung" (connected to the last casing) by setting slips that grip against the inner wall of the previously set casing string. Expandable liner hangers are hung by external expansion of the hanger against the inner wall of the previously set casing string.

3.1.30

liner top packer

LTP

A mechanical barrier device typically with flexible, elastomeric sealing elements that can be run into a wellbore with a smaller initial outside diameter that then expands externally to seal the annulus between the liner and the previously installed casing string. Liner top packers are also called liner packers.

3.1.31**loss of well control****LWC**

A loss of well control incident is an uncontrolled flow of subterranean formation fluids such as gas, oil, water, etc. and/or well fluids into the environment or into a separate underground formation, in which case it is called an underground blowout.

3.1.32**logging while drilling****LWD**

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

3.1.33**maximum allowable wellhead operating pressure****MAWOP**

The maximum allowable operating pressure for a particular annulus, measured at the wellhead relative to ambient pressure. It applies to SCP, thermal casing pressure, pressure from a well control event and operator imposed casing pressure.

3.1.34**mechanical barrier**

A subset of physical barriers that features mechanical equipment; not set cement or a hydrostatic fluid column.

3.1.35**mudline**

Mudline as referenced in subsea operations refers to the seafloor.

3.1.36**mudline packoff or packer**

An upper packer run on the production tubing and set in the production casing below the mudline wellhead to isolate the production riser section from the production casing. These mechanical barrier devices are commonly installed in hybrid wells.

3.1.37**mudline suspension system**

A casing suspension system that allows a well to be drilled using a surface BOP and wellhead. The mudline suspension equipment provides for individual casing hangers to be installed with each casing string that interconnect with each other at a preset point below the mudline. The mudline suspension casing hangers do not provide a pressure barrier.

3.1.38**mudline suspension wells**

A well drilled using a mudline suspension system and a surface BOP. The mudline suspension well may be completed as either a surface well or as a subsea well.

3.1.39**measurement while drilling****MWD**

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

3.1.40**non-aqueous fluid****NAF**

Non-aqueous fluid is a non-aqueous drilling fluid or well circulating fluid. Common NAF systems are diesel, mineral oil, or synthetic fluid based invert emulsions, or other non-water based fluids.

3.1.41**nippling down**

The process of removing well-control or pressure-control equipment such as a BOP system.

3.1.42**nippling up**

The process of installing well-control or pressure-control equipment such as a BOP system.

3.1.43**operator imposed casing pressure**

Pressure in a casing that is operator imposed for purposes such as casing pressure integrity tests (prior to drilling out the shoe), gas lift, fluid injection, stimulation treatments, thermal insulation, etc.

3.1.44**overbalance pressure****OBP**

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

3.1.45**physical barrier element**

Physical barrier elements can be classified as hydrostatic, mechanical or solidified chemical materials (usually cement).

3.1.46**polished bore receptacle****PBR**

A device with a honed internal diameter (ID) sealing surface for landing a production tubing seal assembly or tie back casing.

3.1.47**pore pressure****PP**

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

3.1.48**potential flow zone**

Any zone in a well where flow is possible under when wellbore pressure is less than pore pressure.

3.1.49**production casing**

Casing that is set through a productive interval.

3.1.50**production liner**

A liner that is set through a productive interval.

3.1.51**production riser**

The casing string(s) rising from the seafloor to the wellhead on fixed platforms or the casing string(s) attached to the subsea wellhead rising from the seafloor to the surface wellhead on hybrid wells.

3.1.52**production tubing**

Tubing that is run inside the production casing and used to convey produced fluids from the hydrocarbon bearing formation to the surface. Tubing may also be used for injection.

3.1.53**pressure while drilling****PWD**

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

3.1.54**rate of penetration****ROP**

Common term for drilling rate; usually expressed in units of ft/hour or m/hour.

3.1.55**static gel strength****SGS**

The yield stress of fluids at rest.

3.1.56**structural pipe (or casing)**

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

3.1.57**subsea wells**

Wells drilled and completed with a subsea wellhead located near the seafloor.

3.1.58**subsea wellhead**

A wellhead that is located near the seafloor.

3.1.59**surface casing**

Casing run to isolate shallow formations.

3.1.60**surface well**

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

3.1.61**sustained casing pressure****SCP**

Pressure in an annulus of casing strings that is measurable at the wellhead that rebuilds to at least the same pressure level after pressure has been bled down. SCP is not due solely to temperature induced fluid expansion or a pressure that has been imposed by the operator. See [API RP 90](#) for further information.

3.1.62**tieback casing**

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

3.1.63**well barrier system**

Well barrier system is one or more barriers that act in series to prevent flow. Well barriers that do not act in series are not considered part of a single well barrier system, as they do not act together to increase total system reliability.

3.1.64**wellbore**

The borehole or cased hole sections in a well.

3.1.65**wellhead**

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

3.1.66**well integrity**

A quality or condition of a well in being structurally sound with competent pressure seals by application of technical, operational and organizational solutions that reduce the risk of uncontrolled release of formation fluids throughout the well life cycle.

3.1.67**waiting on cement****WOC**

Waiting on cement, normally expressed in hours, is the period of time after the cement has been placed until the time subsequent drilling or completions operations can resume.

3.2 Abbreviations

ACP	annular casing pressure
API	American Petroleum Institute
APB	annular pressure buildup
BHA	bottom hole assembly
BHCT	bottom hole circulating temperature
BHP	bottom hole pressure
BHST	bottom hole static temperature
BHT	bottom hole temperature
BOEMRE	Bureau of Ocean Energy Management Regulation and Enforcement
BOP	blowout preventer
CGSP	critical gel strength period
CSGS	critical static gel strength
ECD	equivalent circulating density
ECP	external casing packer

EMW	equivalent mud weight
FG	frac gradient
FIT	formation integrity test
HPHT	high pressure, high temperature
LOT	leak-off test
LCM	lost circulation material
LWC	loss of well control
LWD	logging while drilling
LTP	liner top packer
mD	millidarcy
MD	measured depth
MLSH	mud line suspension hanger
MMS	Minerals Management Service
MWD	measurement while drilling
NAF	non-aqueous fluid
ND	nippling down
NU	nippling up
OBP	over balanced pressure
PBR	polished bore receptacle
PIT	pump-in tests
PP	pore pressure
ppge	pounds per gallon equivalent density
psi	pounds per square inch
PWD	pressure while drilling
ROP	rate of penetration
RP	Recommended Practice
SCP	sustained casing pressure
SGS	static gel strength
SPE	Society of Petroleum Engineers
TOC	top of cement
TVD	true vertical depth
WOB	weight on bit
WOC	waiting on cement

4 Barriers

4.1 General

Barrier elements can be classified as either physical or operational. With the exception of operational procedures related to the use of cement as a physical barrier element, operational barriers are not covered in this standard.

Barriers contribute to total system reliability; total system reliability is the probability of barrier success, or one minus the probability that all barriers to uncontrolled flow along a particular path will fail simultaneously. The principles

processes and procedures for planning and implementing barriers are necessary to ensure operations integrity during all life cycle phases of the well. This barrier philosophy should be applied to each potential flow path, considering the consequences of a loss of control.

4.2 Physical Barrier Elements

Physical barrier elements can be classified as hydrostatic, mechanical or solidified chemical materials (usually cement).

4.3 Hydrostatic Barrier Elements

Hydrostatic barrier elements are those in which a column of fluid(s) imposes a hydrostatic pressure which exceeds the pore pressure of the potential flow zone. These fluids may include drilling fluids, cement spacers, cement slurries, water and completion fluids. It is important to understand the hydrostatic contribution of any of these fluids can change with time. Solids settling in drilling fluids or spacers could reduce the hydrostatic pressure at the flow zone. Static gel strength development of cement during hydration will also reduce the transmission of pressure (see 5.7.8). Drilling fluids and spacers also develop static gel strength, although to a lesser extent than cement, and their contribution to loss of hydrostatic pressure should be considered. Some fluids such as NAF may exhibit compressible behavior so downhole temperature and pressure should be considered when calculating the hydrostatic contribution of those fluids. A decrease in the height of the fluid column due to downhole losses may compromise the hydrostatic barrier element and should be taken into account in the planning stages of the operation.

4.4 Annular Mechanical Barrier Elements

4.4.1 General

A mechanical barrier is a seal achieved by mechanical means between casing strings, a casing string and a liner, a casing string and the borehole, a casing string and a wellhead housing, or a liner and the borehole that isolates a potential flowing zone(s). When both cement and mechanical barriers are used in series, it is not possible to physically test them independently to know which is holding pressure. Consequently, both should be designed to be effective and contain the maximum anticipated load. As with all engineering processes, the application of mechanical barriers should be chosen with care. Such barriers may not be necessary or advisable. It is up to the user to exercise due diligence in understanding the variables involved and make the correct decisions.

NOTE When cement cannot be used as a barrier during well construction, mechanical barriers become the primary barriers for isolating annular flow.

Mechanical barriers can be divided into two basic classifications.

- 1) Mechanical barrier elements designed for preventing loss of well control (LWC).
- 2) Mechanical barrier elements designed for preventing sustained casing pressure (SCP).

4.4.2 Mechanical Barrier Elements for Preventing LWC

4.4.2.1 General

Mechanical barriers can significantly reduce the risk of annular flow past them. Annular flows may occur while temporary mechanical barriers such as BOPs or diverters are nipped down or a hydrostatic barrier is removed following cementing operations. These flows may result from:

- loss of hydrostatic pressure as the unset cement column develops static gel strength and supports its own weight;

- cement fluid loss;
- internal cement shrinkage;
- reduced fluid density in the annulus during cement washout operations;
- lost circulation during cementing causing:
 - reduced hydrostatic pressure due to shorter fluid columns,
 - lower than planned top of cement columns leaving potential flow zones un-cemented;
- or combination of the above.

While mechanical barriers are designed to prevent the flow of annular fluids past the barrier element or seal, setting of the barrier may actually increase the chance of fluids entering the cement slurry if the cement slurry is not properly designed. Setting the barrier isolates all potential flow zones below the barrier from all of the hydrostatic pressure above the barrier. This reduction in overbalance pressure (OBP) on any potential flow zones effectively decreases the CSGS as defined in 5.7.8. The pressure in the annulus therefore drops to the pore pressure of the flow zones at an earlier time after the cement is in place, increasing the window of opportunity for fluid to enter the cement slurry. Because of this increased chance of fluid entering the cement, it is very important that the slurry placed across potential flow zones is designed with fluid migration control properties (see 5.7.14). Properly designed cement slurries should be considered to help prevent the fluid from migrating through the annulus once it has entered the cement. If migration is not controlled there is potential for either a cross-flow into a lower pressure zone or a collection of fluid directly below the mechanical barrier.

4.4.2.2 Liner Top Packers

Liner top packers (LTP) are typically run in the well with the liner and set immediately after cementing; however, they may be run and set on a separate trip after the liner has been cemented. LTPs seal the annulus between the liner and the host casing string. Once set, they prevent upward or downward flow. If they are tested after they are set, they may allow select operations to safely proceed without having to wait on cement (WOC). Local regulations may supersede this provision.

The industry has successfully used liner top packers for many years to eliminate/reduce flow after cementing as well as to reduce squeeze work on liner tops. The liner top packer is a proven product when properly designed, installed, and verified for the specific application. Expandable liner hangers with elastomer pack-off elements function both as liner hangers and liner top packers.

4.4.2.3 Expandable Tubulars

Expandable tubular liners or expandable liner hangers provide a mechanical barrier while preserving the maximum interior diameter of the liner. A cone or other device expands the pipe to a larger diameter forming either a metal-to-metal or elastomeric seal with the host pipe. When an expandable liner is installed below a host pipe, the liner is placed on the bottom of the hole and cement is (optionally) circulated around the pipe. Expandable tubulars have reduced burst and collapse ratings, which **shall** be taken into account in the well design.

4.4.2.4 Multiple Seals in a Single High Pressure Wellhead Housing

Some wellhead systems provide several casing suspension and sealing positions in one high pressure wellhead housing. The casing hanger is landed, the pipe is cemented in place and then the seal assembly is energized. In some situations the weight of the casing string may hold the seal in place, while in others it is necessary to engage a locking mechanism.

4.4.2.5 Sub Wellhead Liner Hanger Profiles

Landing profiles can be pre-installed in a host casing to allow installation of liners without using the wellhead hanger profiles. The liners are run with a mating profile and the mechanical seals are subsequently engaged to provide a mechanical barrier in the annulus between the liner and host casing, usually following cementing operations. The liner is an extension or deepening of the host casing. This allows for more casing size flexibility in the well design.

4.4.2.6 Inflatable External Casing Packers

Inflatable external casing packers have inflatable elements mounted on mandrels that are equivalent in strength to the liner or casing string. The advantages of these packers include the ability to run through reduced IDs and seal in larger ID sections of casing or open hole. Some open holes may not be suitable for sealing by an inflatable packer. These include holes with irregularities such as fractures, faults, and unconsolidated formations or with drilling induced hole enlargements or key seats. The mechanical barrier is installed by inflating the packer with cement, drilling fluid, or completion fluid. Sealing elements or elastomers can be designed for specific applications.

4.4.2.7 Hydraulic Set External Casing Packers

Hydraulic set external packers differ from inflatable packers in that the external elastomer element is expanded by compressing it, rather than inflating it. Hydraulic-set external casing packers can be used in situations in which pressure can be applied to the casing string to set the packer. The mechanical barrier is energized by applied pressure that activates hydraulic cylinders within the tool to generate pack-off forces. This generally requires bumping the plug that follows the cement slurry; however, pressure can be applied through alternate means. This mechanical barrier can be installed on the inner casing string anywhere within the casing/casing annulus and does not require that casing be set off bottom. This type packer does not require a load shoulder or other setting device. Packers are available with or without slips and are selected for the diameters of the tubulars involved and anticipated differential pressure across the sealing area.

4.4.3 Mechanical Barrier Elements for Preventing SCP

4.4.3.1 General

Some of the barrier elements designed for preventing loss of well control (see 4.4.2) may also act to minimize the potential for SCP. The barrier elements discussed in this section may prevent SCP but they are not effective for preventing LWC events, either because they do not isolate the entire annular area or because a full seal from the set cement will not have developed while the slurry is in the critical gel strength period (CGSP).

4.4.3.2 Annular Seal Rings

Annular seal rings are mechanical barrier devices with flexible, elastomeric sealing elements that can be run in a well on casing or liners for applications to seal the micro-annulus and voids formed between the cement sheath and the inner pipe string. The sealing element has an outside diameter designed to seal the size of a micro-annulus and should not excessively restrict flow during the hole conditioning and cementing process. The sealing element may or may not be designed to chemically swell and may only deform to seal a micro-annulus or void at the interface between the cement sheath and inner pipe string.

4.4.3.3 Swellable Packers

Swellable packers are mechanical barrier devices with flexible, swellable elastomers that are run in a well on casing or liners. The sealing element is designed to chemically swell when it comes into contact with an appropriate activating fluid such as hydrocarbons or produced water. Due to the limited expansion ratios, swellable packers may not be appropriate for some applications. Swellable packers may be used alone or in conjunction with cement.

4.5 Mechanical Wellbore Barrier Elements

4.5.1 General

A mechanical wellbore barrier is a seal achieved by mechanical means inside casing or the borehole that isolates a potential flowing zone. When cement is used in conjunction with a mechanical barrier, there are two potential barriers and it is not possible to know if one or both is preventing flow. When cement is used as a barrier during well construction, mechanical barriers are complementary to a properly executed cementing operation and both may contribute to the total system reliability.

4.5.2 Downhole Tools

4.5.2.1 General

During well construction operations, downhole tools such as packers, retainers and bridge plugs are typically utilized as temporary mechanical barriers to facilitate rig operations. These tools can be classified as retrievable, permanent or drillable and can be used separately, or sometimes in combination.

Downhole tools have various pressure and temperature ratings and tool selection should consider the pressure and temperature of the application for which the tool will be utilized. Care should be exercised when removing the barriers as there could be a differential pressure across the tools.

4.5.2.2 Cased Hole Retrievable Tools

Packers and retrievable bridge plugs are tools that consist of a sealing device, a holding or setting device and an inside passage for fluids. These tools commonly contain mechanical slips to hold the packer in place and elastomeric sealing elements either mechanically or hydraulically set to provide a seal against the casing. Retrievable tools can be set and released many times in a single trip into the wellbore and can perform multiple functions including providing temporary barriers, testing casing, remedial cementing, etc.

Storm packers can provide a temporary barrier and are typically utilized when a rig is required to evacuate. These packers support the total of the drill pipe and drilling assembly to be hung off below the packer. Storm packers utilize a valve and back-off assembly above the packer, allowing the drill pipe above the packer to be pulled from the wellbore, leaving the packer and drill pipe isolation valve in place with the drill string hanging below.

4.5.2.3 Drillable Bridge Plugs

Drillable bridge plugs can be run in the wellbore, set and then drilled after other operations. The slip system on the tools outer body anchors the plug to the wellbore while a packing element provides a pressure seal. Drillable bridge plugs are constructed of drillable metals such as cast iron or composite materials.

One aspect in which composite and conventional cast iron drillable bridge plugs differ is their life expectancies. Cast iron plugs have a long life and can be left in the wellbore for an extended period of time, depending on the downhole environment. Composite plugs, on the other hand, have a short life expectancy and the tool must be selected with the longevity required for the given application. When utilizing composite bridge plugs, the working life of the plug in the planned downhole setting environment should be considered.

4.5.2.4 Retainers

Drillable squeeze packers are commonly referred to as cement retainers. A retainer is a mechanical barrier that can be set on drill pipe or wireline. The retainer provides isolation both above and below where set, but communication through the retainer can be achieved through a sliding sleeve check valve. The check valve is typically operated by a stinger seal assembly. When the stinger is removed from the retainer, the valve closes and isolates the wellbore below the retainer.

4.5.2.5 Cementing Head

Cementing plug containers and head assemblies provide the means by which conventional casing wiper plugs, or darts to launch subsea plugs, can be launched from the surface without significant interruption of pumping operations. If other wellbore barriers are not in place and the float equipment fails, surface cementing plug containers may function as a temporary wellbore mechanical barrier. Prior to removing the cementing head, ensure adequate wellbore barriers are in place.

Cementing heads **shall** be pressure tested by the supplier to the maximum working pressure rating of the head as part of a regular maintenance program. The cementing head selected **shall** have a working pressure in excess of the maximum anticipated surface pressure for the job. Cementing heads are discussed further in 5.4.5.

4.6 Set Cement as a Barrier Element

4.6.1 General

Regulators require that if the operator plans to remove a barrier element, such as a diverter or BOP stack, the operator **shall** determine when it will be safe to do so.

Determination of the safe WOC time should take into account several factors including whether or not a potential flow zone is exposed in the wellbore or if there is the possibility that one is exposed (if it is unknown). There may be other downhole conditions that could impact the guideline. It is extremely important that any plan for removing a barrier element be modified toward a conservative approach to avoid loss of well control or risk to personnel or equipment. Observations prior, during and after the cementing operation that could impact the plan for removing a barrier element include but are not limited to:

- substantial loss of returns while pumping cement;
- significant deviation from the cementing plan such as inability to maintain the desired density of the slurry, use of less than designed volume of slurry, etc.;
- premature returns of cement slurry to surface;
- measured lift pressure of the cement just prior to bumping the plug indicates the top of cement (TOC) is not high enough in the annulus to isolate the uppermost potential flow zone;
- indications of fluid influx prior to, during or after cementing.

In these cases, confidence in the cement job would decrease and further assessment is needed before removing a barrier element.

4.6.2 Special Operational Requirements

The following are special operational requirements.

- Operators and all involved contractors **shall** perform a risk assessment prior to utilizing foamed cement (see 5.6.5.9 and 5.7.13 for more information on foamed cement), and make sure that the results of this assessment are incorporated in the cementing plan. The risk assessment should address safety, health and environmental risks as well as design and operational risks;
- Operators and contractors **shall** not run tubing in the annulus between the casing and the diverter, or BOP, after completion of the cementing operation and prior to determining the well has no potential for flow.

- Hydrostatic pressure calculations **shall** be performed and results considered prior to commencing any operation that will result in a change in hydrostatic pressure in the wellbore.

4.6.3 WOC Guidelines Prior to Removing a Temporary Barrier Element

If no potential flow zone(s) exist or if alternate physical barrier elements are in place, subsequent operations may commence without WOC, if regulations allow.

If design and operational parameters indicate isolation of potential flow zones, cement **shall** be considered a physical barrier element only when it has attained a minimum of 50 psi compressive or sonic strength. The 50 psi compressive or sonic strength threshold exceeds the minimum static gel strength value needed to prevent fluid influx. Local regulations **shall** be adhered to with regards to WOC. However, caution should be exercised when the specified WOC time is less than the time required for the cement to reach a strength of 50 psi.

Laboratory tests, conducted under simulated downhole temperature and pressure conditions (within the limits of the laboratory equipment) with representative cement, additives and mix water **shall** indicate the sustained development of 50 psi compressive or sonic strength. Care should be taken that sonic strength continues to develop following the cement slurry's initial set and that the first "Time to 50 psi" reading is not an artifact of the initial temperature and pressure ramp used in the testing. See the example below (Figure 1) in which an initial "Time to 50 psi" is recorded in 29 minutes 30 seconds while the sustained development of 50 psi occurs in approximately 3 hrs 30 minutes.

Contingency plans to address a flow should be in place prior to initiating the removal of a temporary barrier element after completing a cement job. This planning should include key parties involved in performing the associated operations and specifically should include the operator, drilling contractor, and cementing contractor. The time from the start of removing a barrier element to securing the exposed annulus **shall** be minimized. Waiting time can be reduced if the operator has the required number of tested or verified barrier elements remaining in place prior to removing the barrier element (such as a BOP), subject to local regulatory requirements.

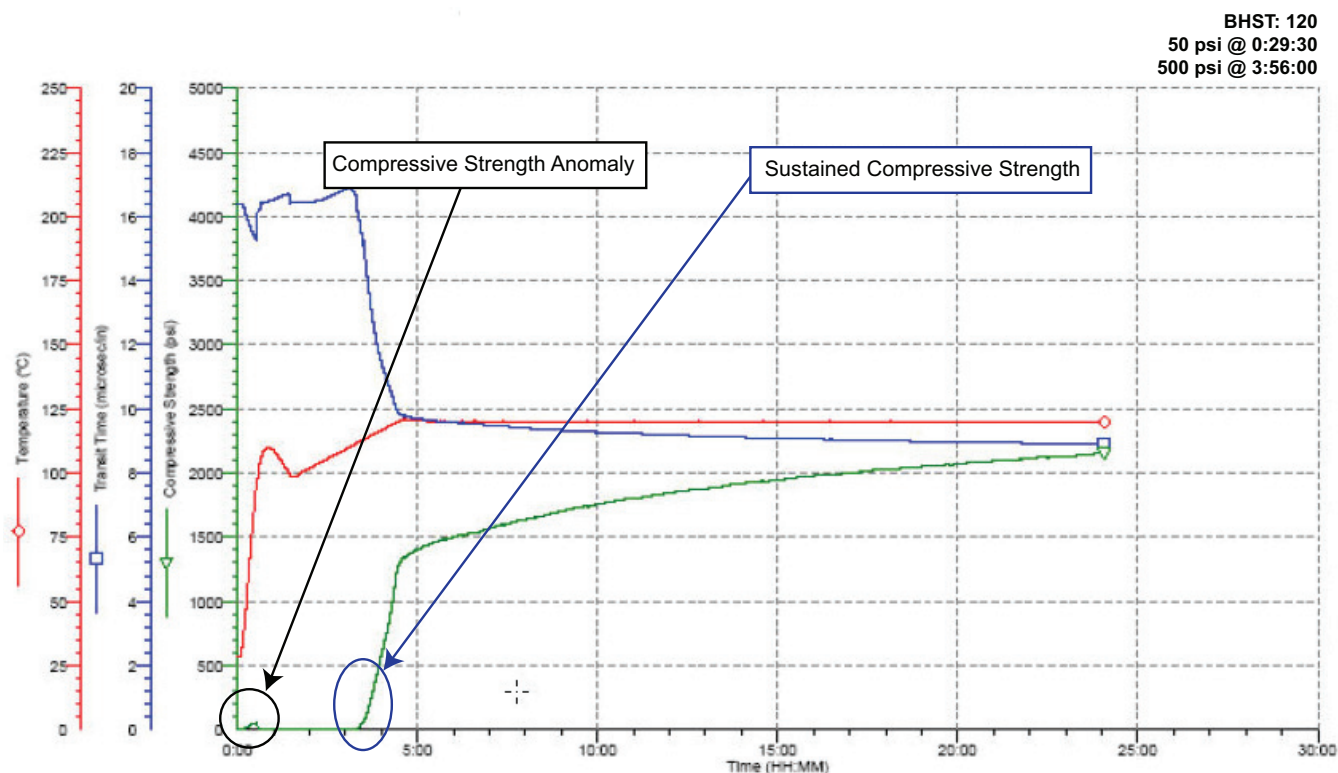


Figure 1—Sonic Strength Anomaly

4.6.4 Cement Wellbore Barriers

4.6.4.1 Shoe Track Barrier Element

A shoe track barrier element is a combination of the two independent float valves and a shoe track of set cement. Under special circumstances (inner-string, reverse cementing, etc.), the use of float valves may not be possible.

Float valves should be rated for the anticipated flow rates and volumes of the fluids pumped during circulation and cementing of the casing string. Float valves **shall** be rated for the differential pressure between the minimum anticipated hydrostatic column above the shoe track and the hydrostatic column in the casing annulus with cement in place. Ensure the float collar is rated for the load imposed when a top cementing plug is landed on it and pressure is applied to verify landing and test the casing. Float valves are typically designed for liquid service (e.g. drilling fluid, cement, etc.). Refer to [API RP 10F/ISO 10427-3](#) for determining service class corresponding to anticipated service requirements.

Float valves may be configured to allow the casing to fill automatically while run into the hole, thereby reducing the surge pressure exerted on the wellbore. These auto-fill devices should be deactivated prior to beginning cementing operations. The impact of auto-fill tools on well control while running casing and procedures for auto-fill conversion should be considered and operational response plans should be in place if flow occurs through the auto-fill float system and up the inside of the casing.

4.6.4.2 Cement Plugs

Cement plugs are set cement located in open hole or inside casing / liner to prevent formation fluid flow between zones or flow up the wellbore. The placement and design of the cement plug should consider specific well conditions such as; pore and fracture pressure gradients, estimated hole volumes, drilling fluid density, presence of hydrocarbons, etc. Slurry properties **shall** be consistent with any regulatory requirements. Cement plugs **shall** be installed and verified as required by regulations.

5 Cementing Practices and Factors Affecting Cementing Success

5.1 Introduction

A well-designed cement job optimizes cement placement through considerations such as laboratory-tested slurry design, honoring pore pressure/ fracture gradient window, use of spacers/pre-flushes, proper density and rheological hierarchy, fluid compatibility and adequate centralization. This section summarizes many of the key drilling issues that affect the quality of a primary cementing operation. This section is not exhaustive, nor does it provide the reader with a comprehensive set of detailed recommendations for well construction. The intent is to highlight the salient aspects that should be considered and summarize the interrelationship between drilling operations and cementing success. All topics discussed are covered in detail in various API, ISO, and other industry publications.

5.2 Hole Quality

Hole quality affects many aspects of the cementing operation. In situations where hole quality could compromise cementing quality, practices exist that may minimize the impact of hole quality. Avoidance of severe doglegs, hole enlargement and spiral patterns in the wellbore will improve the efficiency of drilling fluid displacement during cementing. Use of directional survey data, including azimuth, when modeling centralization and drilling fluid displacement will improve the quality of the results of the simulation.

A caliper log can be a useful tool to confirm the volume of cement slurry required to fill the annulus to the designed TOC. Knowledge of actual hole sizes provides better friction pressure estimations, both for the cementing operation and for running casing. Caliper data of sufficient quality can be used to calculate the centralizer requirements and from centralizer calculations, to calculate flow regimes and rates recommended for effective drilling fluid removal. Sonic and fluid calipers may also be used.

5.3 Drilling Fluid

5.3.1 Drilling Fluid Selection

Drilling fluid (mud) selection and maintenance play a key role in cementing success. Drilling fluid performance affects hole condition (enlargements, etc.), drilling fluid filter cake thickness and gel strength (measured as described in [API RP 13B-1/ISO 10414-1](#) or [API RP 13B-2/ISO 10414-2](#)), drilling fluid mobility, fluid and formation compatibility, and bonding of cement to formation.

Drilling fluid performance is controlled by many factors. Drilling with fluids that provide a thin, low permeability filter cake and low non-progressive gel strengths sufficient for transport of drill cuttings and barite support can be more effectively displaced when cementing. Achieving good cementing success through effective drilling fluid displacement requires proper planning. Computer modeling of cement placement or drilling fluid displacement requires careful evaluation of fluid properties and placement processes.

5.3.2 Drilling Fluid Rheology

Drilling fluid rheology has a significant impact on cement placement. Samples representative of the drilling fluid at the time of cementing should be tested for rheological properties prior to cementing operations. This data should be used in displacement simulations.

5.4 Casing Hardware

5.4.1 General

Casing hardware and auxiliary downhole equipment may be used to enhance the cementing operation. Examples include: centralizers, float equipment, stage collars, external casing packers, liner hangers and liner top packers and expandable casing (mechanical barriers are discussed in Section 4).

5.4.2 Centralizers

Appropriate casing centralization is important to successful cement placement and zonal isolation. Casing centralizers exist in many models and designs and are generally categorized as either rigid, solid or bow-spring models. Auxiliary functionalities such as flow diversion and mechanical friction-reduction are also available. Custom-built centralizers are available for either slimhole or extremely large annular clearances. In order for centralization calculations to be done for bowspring centralizers, performance data as measured according to [API Spec 10D/ISO 10427-1](#) should be used. See discussion of installation under 5.6.5.7. Also, see, [API RP 10D-2/ISO 10427-2](#), [API 10TR4](#) and [API 10TR5](#).

5.4.3 Float Equipment

Float equipment is used to prevent the cement from flowing back into the casing when pumping is stopped and/or pressure released. Test procedures for various classes of float equipment and associated mechanical components are provided in [API RP 10F/ISO 10427-3](#).

Float equipment choice should be matched to anticipated bottom hole temperatures and the pressure differentials expected at the end of the cement job. Specialized float equipment including auto-fill, side-ported, and custom-profiled is also available to address the functionalities of surge-reduction and collapse protection, improved hole cleaning, and ease of running casing, respectively. When utilizing auto-fill float equipment, recognize there will be well control implications while the casing is run in the hole.

A float collar and a float shoe can be used together to provide redundant flow-back control as well as a receptacle for contaminated cement slurry. Some lost-circulation materials (LCM) in the drilling fluid and/or cementing fluids may

preclude or hamper the use of certain float equipment valve designs. Standard float equipment is not designed to provide a gas-tight seal.

5.4.4 Wiper Plugs

Casing and liner wiper plugs, whether conventional surface release or subsea release, provide the function of mechanically separating cementing fluids from the drilling fluid, wiping the internal diameter of the tubulars, and providing a positive indication of the end of displacement. Wiper plugs should be matched to the anticipated bottom hole temperatures, pressures, depths and drilling fluid type. Not all wiper plugs and associated operating systems (releasing darts) are compatible with all types and manufacturers of float equipment and/or stage tools, liner hanger tools, and liner top packers. Tapered diameter casing strings may require customized wiper plug systems. Wiper plugs and associated operating systems should be designed for the specific size and weight of the casing and all other casing hardware components.

5.4.5 Cementing Plug Containers and Heads

Cementing plug containers and head assemblies provide the means by which wiping devices (casing wiper plugs, drill pipe darts, balls, etc) can be launched from the surface without significant interruption of pumping operations. Cementing heads (plug containers) also allow control of cement U-tubing should the float equipment fail. Each type of cementing head has its own specific capabilities in terms of pressure ratings, mechanical operation, load-carrying capacity, and auxiliary capabilities such as allowing rotation or remote operation. These characteristics are published by the manufacturer. Not all casing wiper plugs are compatible with every model of cementing head and float equipment. Cementing heads and plug sets should be checked for compatibility. Plug containers equipped with remotely-operated plug releasing mechanisms reduce risk to personnel and may minimize shut-down time.

Cementing heads should be in good working order and be pressure-tested as per the service provider's requirements. Various components such as the plug releasing mechanism, plug release indicators, valves, threads and o-rings should be examined prior to each use. Thickness testing should be performed as per the service provider's requirements or if a component is suspect. Type-certification is available from the service provider in many instances. A type-certified plug container is one that has fully traceable components with material mechanical properties verified by laboratory tests.

5.5 Close-tolerance and Other Flow Restriction Considerations

Close tolerances may restrict the flow of drilling and cementing fluids during well circulation and cause lost circulation. Close tolerances are often encountered in pipe-to-pipe annuli, liner tops, expandable casings, and between the inner diameter of outer tubulars and some tools such as liner hangers, liner top packers, polished bore receptacles (PBR), stage tools, external casing packers (ECPs), and expandable tubulars. Conventional types of liner hangers also have reduced flow cross-sectional area called "bypass area" from the flow restrictions formed by the unset slips protruding from the hanger body. The bypass area is further reduced after these slips are set against the inner casing wall to "hang" or connect to and suspend the liner from the casing. Equivalent circulating density (ECD) pressure calculations **shall** include any flow restrictions, particularly those of significant length and small cross-sectional area, such as liner overlaps, liner top packers, liner hangers, tieback sleeves, casing connections and drill pipe tool joints.

5.6 Engineering Design

5.6.1 General

Well construction objectives and local regulations determine the extent of cement coverage and cement performance requirements for each well section. Performance requirements include (but are not limited to) gas control, static gel strength development, fluid loss, free fluid, slurry stability, thickening time, and compressive or sonic strength. Mechanical parameters such as, tensile strength, Young's Modulus and Poisson's ratio may also be taken into account in the cement design.

5.6.2 Zonal Coverage Determination

It is important to evaluate which zone(s) have potential for flow in order to plan the cement job to achieve suitable zonal isolation. Such zones should be covered with cement slurries designed to prevent flow after cementing, and the cement placement mechanics should be designed to maximize drilling fluid removal. Zones left uncemented may not flow in the short term if pore pressure is balanced by drilling fluid hydrostatic pressure. However, phenomena such as barite sag and drilling fluid dehydration may lead to SCP.

Cement top selection is influenced by the location of the potential flow zones, regulatory requirements and pore pressure/fracture gradient consideration. Higher density tail slurries may be more easily designed to be “gas tight” (gas controlling) than some lower density lead cements. However, some types of gas controlling cement slurries may be more easily designed based on solids to liquid content rather than density.

5.6.3 Pore Pressure/Frac Gradient

Accurate knowledge of pore pressure and fracture gradient profiles is necessary for successful primary cementing and helps design jobs that prevent lost circulation and annular flows. Pore pressure is a crucial piece of information needed to assess flow potential. The pore pressure and fracture gradient profiles are two of many input values used in computer simulation programs used to evaluate static and dynamic well security.

5.6.4 Temperature

Temperature has the single greatest influence on cement slurry performance. Accurate estimates of cementing temperatures (both static and circulating) are essential to the success of the cement job. These may be available through thermal modeling and or measurement in offset wells. For many wells, API temperature schedules provide adequate estimates of circulating temperatures. However, these schedules are based on data collected in wells in shallow water with little deviation (see [API TR 10TR3](#) on Cementing Temperature Schedules). The API schedules should not be used for wells that vary greatly from these conditions (e.g. deepwater offshore wells or wells with significant deviation). The heat up rate used for a thickening time test can significantly impact the testing result. The heat up rate used for thickening time testing should be based on the anticipated time to bottom for the cement as described in [API RP10B-2/ISO 10426-2](#).

Computer-based thermal modeling programs may be used to develop cementing testing temperatures. Such programs require input information such as static temperature, formation and well fluid thermal characteristics, rheologies, estimated job volumes, planned pump rates and well geometry. The predictions generated by thermal modeling programs may vary significantly; operators may consider employing more than one thermal model to arrive at a cement test temperature schedule. In most circumstances the highest annular temperature found during a cementing operation occurs some distance above the casing/liner shoe.

Temperature information may be obtained from measurement while drilling (MWD) or logging while drilling (LWD) tools as the hole is drilled. Temperatures from MWD or LWD devices tend to be somewhat higher than those derived from models or sensors used on cleanup trips, therefore caution should be applied in using these temperature measurements as the basis for cement testing. Several factors account for this including an elevated drilling fluid suction temperature while drilling compared to initial slurry temperature while cementing. Some bottomhole assemblies and formation types have been demonstrated to give highly elevated MWD readings.

In summary, there are many sources of temperature information. All temperature information should be considered. Sound engineering judgment should be applied to select the best temperature or range of temperatures and the cement should be designed to perform acceptably at that temperature or range of temperatures.