

Hydraulic Fracturing—Well Integrity and Fracture Containment

ANSI/API RECOMMENDED PRACTICE 100-1
FIRST EDITION, OCTOBER 2015



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 © 2015 American Petroleum Institute

Foreword

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

- the term “shall” denotes a minimum requirement in order to conform to the specification;
- the term “should” denotes a recommendation or that which is advised but not required in order to conform to the specification;
- 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	1
3	Terms, Definitions, Acronyms, and Abbreviations	2
3.1	Terms and Definitions	2
3.2	Acronyms and Abbreviations	5
4	Well Planning	6
4.1	General	6
4.2	Groundwater Sampling	7
4.3	Offset Well Data	7
4.4	Simultaneous Operations and Offset Well Considerations	9
5	Well Construction-Casing	9
5.1	General	9
5.2	Conductor Casing	10
5.3	Surface Casing	10
5.4	Intermediate Casing	11
5.5	Production Casing	12
5.6	Production Liners	14
5.7	Casing Wear	14
5.8	Fracture String Design	15
5.9	Wellhead	15
5.10	Re-entry Well Integrity	16
6	Pressure Containment Barriers and Barrier Verification	16
6.1	General	16
6.2	Overview	16
6.3	Geological Barrier	17
6.4	Cement Barriers	17
6.5	Mechanical Barriers	18
6.6	Barrier Verification	19
7	Cementing	21
7.1	General	21
7.2	Pre-job Considerations	21
7.3	Cementing Operations	24
7.4	Cement Sheath Evaluation	24
8	Fracturing Design Considerations	25
8.1	General	25
8.2	Fracture Stimulation Objectives	25
8.3	Fracturing Simulations	25
8.4	Design and Other Considerations	25
8.5	Formation Parameters (Uncertainties)	25
8.6	Controllable Fracture Design Parameters (Decisions)	26

Contents

	Page
9 Fracturing Execution Considerations	27
9.1 General	27
9.2 Completion Execution Objectives	27
9.3 Surface Equipment Selection	27
9.4 Pressure Monitoring and Management	27
10 Fracturing Model Optimization Considerations	28
Bibliography	29

Introduction

This document on well integrity has two areas of focus and is limited to onshore wells. The first is to design and execute the well plan such that useable quality groundwater is isolated and protected during the drilling and subsequent fracture stimulation operations. The second is to design and construct the well and install well equipment to meet the expected fracture load requirements.

Fracture containment combines those parameters that are existing, those that can be established at installation, and those that can be controlled during execution as follows:

- existing—formation parameters with associated range of uncertainties;
- established—well barriers and integrity as created during well construction;
- controllable—fracture design and execution parameters.

Although the typical industry-wide practices associated with well construction are similar, there are considerable variations in the details of individual well design and construction due to varying geologic, environmental, regulatory, and operational settings and requirements. These practices are the result of operators gaining localized and specific knowledge based on experience, along with the development and improvements associated with technology. These experiences and practices are communicated and shared via academic training, professional and trade association literature, and industry standards and publications. Well and fracture design is an iterative and collaborative process balancing equipment limitations and economics with regulatory and technical requirements.

API 65-2 and other standards under development address topics covering the design, construction, and operation of onshore wells that are important and closely related to the subject of well integrity and containment of hydraulic fracturing treatments.

This document provides technical guidance only, and practices included herein may not be applicable in all regions and/or circumstances. This document does not constitute legal advice regarding compliance with legal or contractual requirements or risk mitigation. Where regulatory requirements are mentioned, it is not intended to be all inclusive. The operator is responsible for determining compliance with applicable legal requirements.

Hydraulic Fracturing—Well Integrity and Fracture Containment

1 Scope

1.1 This document contains recommended practices for onshore well construction and fracture stimulation design and execution as it relates to well integrity and fracture containment. The provisions in this document relate to the following two areas.

- a) Well integrity: the design and installation of well equipment to a standard that
 - protects and isolates useable quality groundwater,
 - delivers and executes a hydraulic fracture treatment, and
 - contains and isolates the produced fluids.
- b) Fracture containment: the design and execution of hydraulic fracturing treatments to contain the resulting fracture within a prescribed geologic interval. Fracture containment combines those parameters that are existing, those that can be established at installation, and those that can be controlled during execution:
 - existing—formation parameters with associated range of uncertainties;
 - established—well barriers and integrity as created during well construction;
 - controllable—fracture design and execution parameters.

1.2 The guidance from this document covers recommendations for pressure containment barrier design and well construction practices for onshore wells that will undergo hydraulic fracture stimulation. This document is specifically for wells drilled and completed onshore, although many of the provisions are applicable to wells in coastal waters.

1.3 This document does not attempt to address the full well life cycle of well operations although a brief paragraph on fracture stimulation for re-entries is included in 5.10. This document is not a detailed well construction or fracture design manual. This document does not apply to continuous injection operations such as water disposal, water-flooding or cuttings re-injection wells, or any other continuous injection operation.

1.4 API 100-2 is a companion document that also contains recommended practices applicable to the planning and operation of hydraulically fractured wells. This document includes recommendations for managing environmental aspects during well planning, construction, and execution.

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 Standard 65-2, *Isolating Potential Flow Zones During Well Construction*

API Recommended Practice 100-2, *Environmental Aspects Associated with E&P Operations Including Hydraulic Fracturing*

3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

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

3.1.1

annulus

The space between the borehole and tubulars or between tubulars.

3.1.2

aquifer

A subsurface formation that is sufficiently permeable to conduct groundwater and to yield economically significant quantities of water to wells and springs.

3.1.3

barrier

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

3.1.4

calibration test

A small injection treatment, performed prior to the main hydraulic fracturing treatment, to acquire job design and execution data.

3.1.5

cased hole

The wellbore intervals in a well that are cased with casing and/or a liner.

3.1.6

centralizer

A mechanical device that is attached to the outside of the casing and used to facilitate running casing to the desired depth and to assist in centering the casing in the wellbore.

NOTE 1 These devices are designed to contact the wall of the hole the casing is being run in and center the casing in the well and/or keep the casing from contacting the wellbore wall.

NOTE 2 These can be either bow spring, rigid, or solid body devices (see API 10D-2).

3.1.7

completion string

The string consists primarily of production tubing, but also includes additional components such as gas lift mandrels, chemical injection and instrument ports, landing nipples, and packer or packer seal assemblies.

NOTE The completion string is installed inside the production casing and used to produce fluids to the surface.

3.1.8

conductor casing

Casing that supports unconsolidated sediments providing hole stability for initial drilling operations.

NOTE 1 This is normally the first string set and provides no pressure containment.

NOTE 2 This string can also provide structural support to the well system.

3.1.9

critical separation well

Wells where the zone to be fracture stimulated is close to the base of useable quality groundwater.

3.1.10**float equipment**

Casing accessories that contain check valves and become part of the lower section of a casing string for the purpose of preventing the reverse flow of cement once placed in a wellbore annulus.

3.1.11**formation fluid**

The fluid present within the pores, fractures, faults, vugs, caverns, or any other spaces of a formation.

NOTE The physical state of formation fluid may be liquid, gas, or both and include various types such as hydrocarbons, fresh or saline water, carbon dioxide, hydrogen sulfide, etc. and may be naturally formed or injected therein.

3.1.12**formation integrity test****FIT**

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

NOTE See definition of **leak-off test**.

3.1.13**fresh water**

Water generally characterized by having low concentrations of dissolved solids.

NOTE Multiple regulatory agencies and legal definitions of this term exist and should be checked for applicability to a specific situation.

3.1.14**geological barrier**

The formations that have the properties to contain fluid pressure generated by the hydraulic fracturing process.

3.1.15**hydraulic fracturing**

The propagation of fractures in a rock layer, as a result of the action utilizing one or more of the following: a pressurized fluid, chemical additives, and physical proppants, in order to release petroleum, natural gas, or other substances to be extracted.

NOTE Some areas with water sensitive shales use energized fluid jobs (e.g. N₂, CO₂, LPG, LNG, or any combination) with no chemical additives instead of commonly used water-based fluids. Some hydraulically fractured operations are done without adding proppant.

3.1.16**intermediate casing**

The casing that is set when geological characteristics or wellbore conditions require isolation before drilling to the target formation can be continued.

NOTE These conditions include, but are not limited to, prevention of lost circulation, formation fluid influx, or hole instability. Multiple intermediate casing strings maybe run in a single well.

3.1.17**kick out**

The instrumentation used to control or take an engine offline or disengage a pump when a certain pressure has been reached or a safety feature to avoid an overpressuring event.

3.1.18**leak-off test****LOT**

A procedure used to determine the fracture pressure in the open or exposed formation, usually conducted immediately after drilling below a new casing shoe.

3.1.19**liner**

A liner is a casing string that does not extend to the top of the well or to the wellhead.

NOTE The liner can be fitted with special components so that it can be connected or tied back to the surface at a later time.

3.1.20**liner hanger**

A device used to attach a liner to the internal wall of a previously set casing string or liner.

NOTE Conventional liner hangers are connected to the last casing (i.e. hanger) by setting slips that grip against the inner wall of the previously set casing string. Expandable liner hangers are attached by expansion of the hanger against the inner wall of the previously set casing string.

3.1.21**mechanical barrier**

A subset of physical barriers that consists of mechanical component(s).

NOTE Set cement or a hydrostatic fluid column are not considered mechanical barriers.

3.1.22**orphaned well**

A well that is inactive and where no responsible or liable party has been identified.

3.1.23**packer**

A device that can be run into a wellbore with a smaller initial outside diameter that then expands externally to seal the wellbore.

3.1.24**Poisson's ratio**

The ratio of the proportional decrease in a lateral measurement to the proportional increase in length in a sample of material that is elastically stretched.

3.1.25**pressure-relief system**

The components including valves, piping, and stacks that protect equipment from overpressure conditions during operations.

3.1.26**production casing**

The innermost casing or casing and liner that is designed to withstand completion and production loads.

3.1.27**production liner**

A liner that is set through the productive interval.

3.1.28**production tubing**

The tubing that is run inside the production casing and used to convey produced fluids from the hydrocarbon-bearing formation to the surface.

NOTE Tubing can also be used for injection.

3.1.29**risk assessment**

The determination of quantitative and qualitative (or both) value of risk related to a situation that has a recognized hazard.

3.1.30**shoe track**

The joint or joints of casing at the bottom of the casing string, generally between a guide shoe or float shoe and a float collar, from which cement is not displaced in order to improve the quality of the cement in the annulus immediately outside the bottom of the casing.

3.1.31**surface casing**

The casing run to isolate shallow formations and designed to meet the necessary regulatory requirements for isolating useable quality groundwater.

3.1.32**tieback casing**

The casing that can be run from a liner hanger back to the wellhead after the initial liner and hanger system have been installed.

3.1.33**top job**

A cement placement operation performed from the surface by top filling the annulus from surface.

3.1.34**tubulars**

General term that includes drill pipe, casing, or tubing.

3.1.35**useable quality groundwater**

Subsurface water suitable for consumption by humans or animals with or without treatment.

NOTE The intent of this term is to define water that is protected by regulation.

3.1.36**well integrity**

The quality or condition of a well in being structurally sound with competent pressure seals (barriers) by application of technical, operational, and organizational solutions that reduce the risk of unintended subsurface movement or uncontrolled release of formation fluid.

3.1.37**workstring**

The string of tubulars used to perform service work or to convey stimulation treatment.

3.1.38**Young's modulus**

A measure of elasticity, equal to the ratio of the stress acting on a substance to the strain produced.

3.2 Acronyms and Abbreviations

AOI	area of investigation
APB	annular pressure buildup
bpm	barrels per minute
DFIT	diagnostic fracture injection test
DLS	dog-leg severity

DTS	distributed temperature sensing
ECD	equivalent circulating density
ESD	equivalent static density
FIT	formation integrity test
IADC	International Association of Drilling Contractors
LOT	leak-off test
MOC	management of change
ppa	pounds proppant added
ppg	pounds per gallon
psi	pounds per square inch
PV	plastic viscosity
SCP	sustained casing pressure
SPE	Society of Petroleum Engineers
TOC	top of cement
YP	yield point

4 Well Planning

4.1 General

4.1.1 Well integrity begins with well planning. Successful and safe well execution is the end result of good and early multi-disciplinary planning by drilling engineers, geologists, geophysicists, regulatory personnel, completion engineers, and production engineers amongst others.

4.1.2 The fracture stimulation load can be the highest load the well may experience. Therefore, the well design process for wells to be fracture stimulated should begin with the completion engineer providing the drilling engineer with a high level fracture design. This design should include

- estimated stimulation loads (treatment and flowback),
- production casing size,
- fluid information (including any corrosion issues), and
- isolation and barrier requirements.

Rock properties needed for fracture design can be determined with the aid of seismic and/or log data before drilling or via logs, cores, and fracture monitoring run on the first few wells in a new prospective area. Collaboration between the geology, geophysics, drilling, completion, and production disciplines is necessary for a robust basis of design. Additional input can be sought in the well design from other specialists such as metallurgists and directional planners. Many operators and service companies have fracture design and rock mechanics specialists who work together on such fracture designs.

The drilling engineer should have additional subsurface information such as the following:

- a) the depth of the useable quality groundwater protection typically obtained from the local regulatory agencies;
- b) formation tops;
- c) pore pressure and fracture gradient plots;
- d) current or potential problem zones such as injection, loss, corrosion, and flow;
- e) various other information specific to the local area.

4.1.3 The information listed in 4.1.2 is used to determine the number and location of casing seats/barriers needed to drill the well. The importance of having a complete drilling program and preliminary completion design prior to starting a well cannot be overemphasized. The thoroughness with which wells are planned will contribute greatly to the successful and safe accomplishment of the project objectives. The multi-discipline team shall recognize the distinct character of each well and design the well plan accordingly. The drilling program should contain the important data required to reach the geological and completion objectives in the safest, most economical manner. Each phase of the operation shall be analyzed for possible problems, potential risks, and mitigation actions developed by the multi-disciplinary team to determine the optimum design.

4.1.4 The plan should highlight any potential hazards along with appropriate contingency plans. The program must be planned to comply with applicable regulations as well as the operator's policies and practices. When executed properly, the well will provide the necessary containment for fracture stimulation.

4.1.5 Additionally, internal and external stakeholder involvement early in the planning phase can result in improved overall project performance (see API 100-2 and API 100-3). Advanced planning is typically required for regulatory and legal notifications particular to local requirements for various phases of the operations; these should be part of the project scheduling time line.

4.1.6 After the well is drilled and prior to fracture stimulation, a review and confirmation of the actual well construction including barriers should be undertaken to confirm that the well integrity and fracture containment are within specifications for the actual planned fracture stimulation.

4.2 Groundwater Sampling

Once the location for a well has been selected and before the well is drilled, groundwater sources should be identified. Additionally, rivers, creeks, lakes, ponds, and nearby water wells should also be identified. If the operator elects to conduct baseline groundwater sampling, it should be completed prior to initiating fracturing operations. See API 100-2 for more detail on groundwater sampling.

4.3 Offset Well Data

4.3.1 General

Offset information should be gathered and reviewed. Proximity of offset wells, offset water wells, and other potential hazards need to be identified and the risks evaluated.

Wells that are operating or abandoned (including orphaned wells) that are near current drilling and hydraulic fracturing operations pose potential risk to containment of fracturing and well fluids. Well collision (inadvertent intersection of two wellbores) is not addressed in this section. Operators should establish an area of investigation (AOI) around each well being drilled and hydraulically fractured to assess and mitigate potential risks.

4.3.2 Area of Investigation

4.3.2.1 An AOI is a three-dimensional area of the subsurface where there is the potential for unintended fluid migration associated with the fracturing process. Generally, the AOI is determined by

- existing and legacy wells;
- geological heterogeneity (layers, permeability, stress, natural fractures, non-sealing faults, etc.);
- direction of hydraulic fracture growth; and
- fracture height and half-length (design and observed).

4.3.2.2 The AOI height is controlled by one or more confining layers (geologic barriers) above which the fracture will typically not grow. The AOI length (perpendicular to the direction of fracture propagation) will be controlled by the length of the well (for horizontal wells) with minimal additional length beyond the toe of the well. The AOI width (in the direction of fracture propagation) will have the largest uncertainty and thus will require the largest safety factor. AOI width applies to both vertical and horizontal wells. For vertical wells with uncertain direction of propagation, the AOI length and width are the same.

4.3.2.3 Within the AOI, the operator should identify well penetrations as well as potentially non-sealing faults prior to drilling. In new exploration areas, there may be no wells. In many areas, however, there may be many wells and identifying each well, its location and its condition may be difficult. Methods to locate wells within an AOI includes, but is not limited to the following:

- a) company records;
- b) records of offset operators;
- c) public databases;
- d) regulatory agency records;
- e) maps;
- f) air or satellite photograph;
- g) landowner interviews;
- h) field reconnaissance;
- i) magnetometer surveys to detect hidden metal casing;
- j) satellite radar to detect and 2D map injection pressures.

4.3.3 Risk Analysis

For wells within the AOI, the operator should conduct a risk assessment to evaluate the potential impacts on other well(s). This risk assessment should consider the condition of the well(s) and should address the following questions.

- a) What is the location of each well within the AOI?
- b) Where is that well in relation to the well being drilled and fractured?
- c) What is that well's location in regard to the estimated fracture growth?

- d) What is known about the condition of that well's construction integrity including any plugs?
- e) Are there faults or other geologic heterogeneities potentially connecting that well with the well being drilled and hydraulically fractured?

4.3.4 Risk Mitigation

For each identified risk, the operator should put mitigation steps into place to protect against loss of containment. Some risk mitigation steps may include:

- a) redesigning the well to avoid the hazard (location, lateral length, etc.);
- b) redesigning the completion (perforation cluster location, fracture size, stage avoidance, etc.);
- c) intervening in the well either to confirm or to provide integrity;
- d) monitoring the well while performing the drilling or fracturing operations for indications of communication;
- e) not drilling the well.

4.4 Simultaneous Operations and Offset Well Considerations

As part of the risk assessment, careful consideration should be given to avoiding communication between surrounding wellbores, including wells being drilled, produced, completed, and/or fracture stimulated, and abandoned wells. Actively drilling in an area where wells have been fractured or are being fractured could result in lost circulation, stuck pipe, a fluid kick (due to reservoirs being charged due to fracture stimulation but not flowed back), or a loss of well control. The influence of the pressure from wells being stimulated can be observed at distances in excess of the modeled fracture length.

Key considerations should include the following.

- a) Identifying and establishing an agreed process for the management of the fracturing operations and an assessment of their potential impact on any offset operations (drilling, production, interventions, etc.).
- b) Creating an internal network with other stakeholders (e.g. interventions manager, completions manager, new wells delivery manager, etc.), in order to efficiently exchange information and generate an appropriate schedule.
- c) Establishing a relationship with the other regional operators and service companies, in order to efficiently exchange information, determine proximity of offset operations, and share intervention schedules.
- d) Investigating regional and localized stress-state directions.
- e) Developing seismic interpretation and inferred faulting/fracturing regime across the structure.
- f) Generating a conservative estimate of fracture half-length based on experience and historical evidence.
- g) Capturing the necessary information from multiple sources and compile in a single location. Display this information in a meaningful and easy to interpret manner (e.g. avoidance mapping).

5 Well Construction—Casing

5.1 General

5.1.1 Casing design and selection are critical to well integrity. The casing shall be designed to withstand the various forces (e.g. axial, collapse, and burst) that are exerted on it while running in the hole, as well as the loads that it might be subjected to during drilling, hydraulic fracturing, and different phases of the life of well.

Confirmation of wellbore integrity is required in order to preserve isolation of useable quality groundwater and other distinct formations, thereby providing an integral conduit for production to the surface gathering system.

5.1.2 An operator should have documentation and guidance on casing design, based on accepted industry practice. Casing used in oil and gas wells should meet API 5CT or similar industry standards that can be mandated by a governmental or regulatory body for the protection of useable quality groundwater and the overall wellbore integrity. Casing strings used in a well should be designed to withstand the anticipated load-cases to which they will be exposed or subjected, including drilling, workover, hydraulic fracturing, production, corrosion, erosion, and other factors. The application of used casing in new wells is outside the scope of this document.

5.1.3 Well design and construction generally consists of four main components that are focused on the various casing strings used. These are: conductor casing, surface, intermediate, and production. This section discusses design considerations for those casing strings that protect useable quality groundwater or contain the hydraulic fracture stimulations loads. Additional components that are discussed include fracture/tie-back strings, casing heads, production liners, and wellheads.

5.2 Conductor Casing

Typically the first casing to be installed in the well is the conductor casing. The conductor casing serves as the foundation for the well. The purpose of the conductor casing is to contain the unconsolidated surface sediments and in some cases support subsequent wellhead loads. Typically, below the conductor-drive pipe, there is harder, more consolidated rock. Thus, the conductor-drive pipe keeps the unconsolidated surface sediments in place as the drilling operations proceed. Requirements for the conductor hole vary by state and area. Conductor setting depth is usually 50 ft to 100 ft (15 m to 30 m) except in areas where geotechnical constraints dictate otherwise.

The conductor-drive pipe is installed either by drilling a hole or using a hammer to drive the casing. When installed by drilling a hole, the casing is cemented in place. The cement provides structural integrity and a seal to block downward migration of surface pollutants. The conductor hole shall be drilled using air or water-based fluids. There are instances where it is appropriate to hammer the conductor casing into place.

5.3 Surface Casing

5.3.1 General

The primary purpose, of the surface casing string, is the protection (through isolation) of any useable quality groundwater. Surface casing is designed to meet the necessary regulatory requirements for isolating useable quality groundwater. In addition this casing string shall be suitable to contain load-cases that it may be subjected to while drilling the next hole section and prior to the setting of the next casing string.

5.3.2 Surface Casing Depth and Useable Quality Groundwater

The surface hole is typically drilled to a predetermined depth based on consideration of useable quality groundwater depth, localized geology, regulatory requirements, and pressure control requirements for subsequent drilling operations. The surface hole is typically drilled using air, mist, water, or water-based drilling fluids. Local regulations often dictate the minimum setting depth of the surface casing, and the vast majority of local regulations require that the casing be set below the known useable quality groundwater at the drilling location. In the absence of regulatory guidance, the surface casing depth should be a minimum of 50 ft (15 m) below base of the groundwater. Items to consider for surface casing setting depth include

- a) depth of useable quality groundwater,
- b) competent formation below useable quality groundwater,
- c) sufficient shoe track to manage contaminated cement,

- d) potential flow zones, and
- e) permafrost considerations (arctic environments only).

5.3.3 Casing Centralization

Surface casing should be centralized in order to provide adequate casing standoff for mud removal and cement placement. Centralization requirements are often specified by local regulatory agencies. Information related to centralizer selection and placement can be found in API 10TR4 and API 10D-2.

5.3.4 Cement Placement Verification

The application of industry best practice to cementing operations is critical in achieving the necessary integrity of the surface casing string. Surface casing should be fully cemented back to surface, completely isolating any useable quality groundwater. The cement should be designed for surface returns but at a minimum shall cover useable groundwater zones or potential flow zones exposed within the open-hole section.

If cement returns are not observed at the surface corrective actions shall be taken per local regulations.

5.3.5 Casing Testing and Casing Shoe Test

5.3.5.1 After the surface casing string cement has been deemed to have developed the required compressive strength and prior to drilling out, the surface casing should be pressure tested (commonly known as a casing pressure test). Casing pressure tests can be performed immediately after bumping cement plug (green cement pressure test) in lieu of waiting for cement to set. Local or federal regulations typically dictate surface casing pressure test requirements.

5.3.5.2 Immediately after drilling out of the surface casing plus a short interval of new hole, a casing shoe test (FIT or LOT) should be performed if feasible in order to confirm that the cement around the shoe has sufficient strength to protect the useable quality groundwater and to support the maximum pressures [mud weights, mud, or cement equivalent circulating density (ECD), kick tolerances, etc.] that will be required to drill the next open-hole section. If the results of the formation integrity test (FIT) are inadequate, remedial measures can be necessary.

5.3.5.3 In some instances it may be difficult to obtain a valid shoe test due to one or more of the following cases.

- The surface casing is set shallow [<500 ft (152 m)] consequently the test pressure may be very low [<50 psi (345 kPa)] and it is difficult to perform and measure the test.
- A highly permeable zone or loss zone not connected to zones covered by the casing and cement above is penetrated when drilling the hole below the shoe and adequate pressures cannot be achieved due to these thief zones.

5.3.5.4 The operator should design and execute a quality cement job around the surface casing shoe and across useable quality groundwater sources. Refer to local regulations concerning testing casing shoes.

5.4 Intermediate Casing

5.4.1 General

After the surface casing has been set, appropriately cemented and pressure tested, the drilling of the intermediate hole section can proceed. In some instances, a well can be safely drilled from the surface casing shoe to the total target depth. The need to run an intermediate casing string is determined during the well planning process. Intermediate casing strings may also be used on a contingency basis. The purpose of drilling the intermediate hole section and running/cementing the intermediate casing string is to isolate those subsurface formations that may cause any drilling problems such as potential borehole stability issues, lost circulation, corrosive zones, flow zones, or higher pressure zones. In addition the intermediate casing may

also provide protection of useable quality ground water where useable quality groundwater sources are deeper than surface casing setting depth.

5.4.2 Top of Cement—Useable Quality Groundwater Depth Considerations

In many cases, it is not necessary to cement the intermediate casing back to the surface in order to provide the required level of isolation. This is especially true in the cases where the initial surface casing string and cement placement is fully protecting the identified groundwater zones. In those cases where the intermediate casing string is not cemented back to the surface, at a minimum the cementing operation should be designed to extend cement isolation above potential hydrocarbon-bearing zones, deep useable quality groundwater, offset injection well zones, and geologic hazards.

5.4.3 Casing Hardware

Intermediate casing should be centralized in order to provide adequate casing standoff for mud removal and cement placement. Information related to centralizer selection and placement can be found in API 10TR4 and API 10D-2.

5.4.4 Casing Testing and Casing Shoe Test

Intermediate casing should be tested. This test may be required by local or federal regulations. A casing shoe test (FIT or LOT) should be performed in order to confirm that the shoe has sufficient strength to support the maximum pressures (mud weights, mud or cement ECDs, kick tolerances, etc.) that will be required to drill the next open-hole section. If the test results of the FIT are inadequate, remedial measures may be required.

In the case of an open-hole completion, the intermediate casing is the last casing string to be cemented in place, and the cement should satisfy the requirements as stated in 6.4.1.

5.5 Production Casing

5.5.1 General

After the production hole section has been drilled, the production string (casing or liner) is run to the design depth. The production string may use cement, inflatable packers, swellable elements, or other approaches to isolate between one or more of the proposed stimulation zones. The purpose of a production string and its isolating medium is to house the primary completion components and establish isolation between the producing zone(s) and other subsurface formations.

5.5.2 Hydraulic Fracturing Load Considerations

5.5.2.1 Hydraulic fracturing places high stresses on the casing resulting from the pump pressures that are required to fracture the formation. The loads experienced during hydraulic fracturing operations will be some of the most extreme experienced during the life of well and typically dictate the production casing design. The loads resulting from the fracture stimulation treatment can approach the design limits of the equipment and, although only for a short duration, the design envelope shall account for these conditions.

5.5.2.2 In addition, the temperature reduction associated with placing such treatments will increase the loads. Where casing annuli may be accessed, the effective burst loads can be reduced by applying backup pressure on the annular casing strings during hydraulic fracturing operations. Some regulatory bodies do not allow backup pressure to be applied to casing annuli. Instead, they require these sections to be left open to the atmosphere during hydraulic fracturing or stimulation events in order to monitor the quality and status of the isolation during the treatment.

5.5.2.3 Fracturing or tie-back strings are run when the production or intermediate casing string has not been designed for the hydraulic fracturing load conditions. Typically such strings are deployed for the duration of the hydraulic fracture treatment and may be removed and replaced with a production string at a later date. See additional comments on fracturing strings in 5.8.

5.5.3 Design Considerations

The production casing and the connections will serve as the fundamental pressure containment vessel for the well. Factors related to hydraulic fracturing treatments performed down the production casing string that need to be fully considered include the following.

- a) Treating-test pressure—the hydraulic fracture treating pressures are typically the highest burst loads on the production casing.
- b) Temperature change—the cooling of the casing due to the fracture fluids being pumped during hydraulic fracture treatments can result in the development of significant tensile loads at the surface.
- c) Casing bending—bending loads are always present in horizontal wells. The wellbore trajectory and degree of dog-leg severity (DLS) will impact the resulting load.
- d) Connection and casing selection—connection selection considerations should include the following:
 - fracture stimulation loads,
 - flowback loads,
 - production loads,
 - casing running loads specifically maximum sealing torque rating when rotating casing,
 - connection bending strength,
 - compressive and tensile capacity,
 - need for gas-tight seal if applicable,
 - fatigue loads—fatigue should be considered in deeper/longer laterals where casing has to be rotated in the hole, high number of fracture stages, and/or higher temperature/higher pressure wells.
- e) Corrosion, erosion, and other metallurgical requirements should be included.
- f) Casing wear (see 5.7).

5.5.4 Casing Running Considerations

Proper casing running practices such as controlling running speed and circulation rates while monitoring fluid returns, torque, and hook load readings, should be considered in order to manage ECD and torque and drag. For makeup of API connections, refer to API 5B. The manufacturer's makeup/handling procedures should be used for proprietary connections.

5.5.5 Casing—Completion Hardware

Casing centralizers should be used in vertical and build sections of those wells where the cement is being considered as a barrier to the growth of hydraulic fractures (see 7.2.2). Casing should be centralized in order to provide adequate casing standoff for mud removal and cement placement.

The casing pressure test shall take into account the pressure activated completion hardware such as toe subs, shear, and toe guns. This equipment has a specific operating envelope and this will need to be aligned with regulatory requirements.

5.5.6 Cement Job Execution

See 7.3 for minimum cementing requirements.

5.5.7 Casing Pressure Testing

Prior to hydraulic fracturing operations being performed down the production casing, the casing shall be pressure tested to the maximum anticipated surface pressure to which it will be exposed. If the production casing integrity is not sufficient to withstand the required treating pressure, additional remedial operations or approaches such as isolating the casing with a frac string or applying backup pressure shall be considered in order to deliver the hydraulic fracture treatment and retain integrity. In special cases, the operator may be limited to a lower test pressure (e.g. toe guns). In the case in which the operator is utilizing toe guns or pressure actuated sleeves, the test pressure should consider the minimum actuation pressure of the guns or sleeves.

5.6 Production Liners

When a production liner is used, the intermediate casing string may become an integral part of the production system. Liner hanger systems typically have expandable metal seals or liner-top packers that isolate the producing formation from the previously set casing. The production liner may use cement, inflatable packers, swellable elements, or other approaches to isolate between one or more proposed stimulation zones. When a production liner is run, several options exist for the design of the casing string immediately above. A fracture string or tie-back string can be inserted into the polished bore receptacle located either above or below the liner-top packer, thereby fully isolating the above casing string from the fracture pressure. Alternatively, the intermediate casing can be designed for production operations and fracture stimulation in which case casing wear needs to be considered.

In the case of open-hole liners, only the parent casing and the liner hanger shall be tested in accordance with 5.5.7.

5.7 Casing Wear

In order to assess the condition of a casing string through which drilling operations have occurred and will be exposed to hydraulic fracturing, consideration should be given to running a casing evaluation log prior to performing the hydraulic fracture treatments. Some companies and regulatory bodies have a predetermined number of rotating hours for drilling exposure of casing strings after which they require that a casing evaluation log be run in order to determine the subsequent condition of the casing. If it is determined that the wall thickness is below the safety requirements set out in the basis of design, then some other isolation means such as a frac or tie-back string should be run to restore well integrity. Alternatively, backup pressure may be applied or the fracture treatment modified to lower pressure requirements.

Consideration of potential casing erosion during the fracture stimulation should be taken into account. Following are some factors that may contribute to high erosion:

- a) using long laterals where there are a high number of stages;
- b) using angular proppant;
- c) using API connections or connections without relatively smooth internal bores;
- d) having abrupt changes in diameter of the casing just in or below the wellhead;
- e) using high downhole fluid velocities;
- f) any combination of these.

5.8 Fracture String Design

5.8.1 The fracture string or tie-back string can be tubing, drill pipe, or casing, can range from approximately 2⁷/₈ in. (7.3 cm) up to 5¹/₂ in. (14 cm) external diameter, and is designed to be run prior to the hydraulic fracture stimulation. Some well designs are set up to run a fracture/tie-back string. If the fracture string is to be used on multiple wells, it should be inspected on a regular basis.

5.8.2 The fracture string is an additional barrier in the wellbore to protect the permanent casing strings from damage due to the high treating loads that will be imposed on the casing during hydraulic fracturing operations. A fracture string or tie-back string is usually landed close to the top of the formation with either a production casing packer or directly tying into a liner hanger by means of a polished bore receptacle. In the case of free moving or uncemented pipe, as with a fracture string or a tie-back string, the operator should perform a tubing movement analysis associated with relevant load-cases. The four fundamental tubing movement effects include the following.

- a) Ballooning—ballooning load, due to internal pressure differential, will cause a shortening of the pipe.
- b) Thermal—thermally induced loads due to temperature changes during fracturing or production operations will cause changes in pipe length.
- c) Piston and plug—piston and plug forces, due to exposed surface area, will cause a shortening of the pipe.

5.8.3 A number of additional factors can affect tubing movement calculations, including but not limited to complete tubing geometry, any annular support pressure that may be provided, the weight of the fluid internally and externally, the pipe weight, the pipe grade, the wellbore trajectory, and frictional forces. If the pipe is free to move, then it is important that there is sufficient capability within the polished-bores/seal-bores to service the required string stroke and retain the necessary sealing capability.

5.9 Wellhead

5.9.1 General

The surface well construction component is the wellhead that completes the well barrier system. This provides pressure containment and structural support. The pressure isolation of the casing and tubing strings at the surface requires wellheads that are installed to handle the maximum anticipated pressure.

5.9.2 Wellhead Seals and Casing Hangers

The fracture loads and temperature range need to be considered in the selection of seal materials and production casing hangers. Extreme downward force can be exerted on the wellhead components. Fracture operations apply additional tensile forces on the production casing and subsequently the casing hanger. The effects of temperature and pressure changes on the casing string should be calculated during well design. The casing hanger load rating should be specified to maintain string suspension throughout the fracture process.

5.9.3 Wellhead Isolation Tools

If the wellhead is not sufficiently rated to manage the calculated fracture treating pressures, then a wellhead-isolation tool should be used to isolate the wellhead from the pressure applied during hydraulic fracturing. The sealing areas on these isolation tools shall be inspected and properly installed to avoid seal failure. The operator, wellhead vendor, and fracture stimulation vendor should review the loads and flow profiles for safe application of such devices. Refer to the service company's technical information for installation and operation procedures.

These wellhead isolation tools can also be used to prevent erosion of valves or the wellhead from proppant during hydraulic fracturing.

5.10 Re-entry Well Integrity

Well integrity is critical when re-entering a mature well to hydraulically fracture new or previously completed zones. A lack of structural integrity, within the casing and/or cement, could result in uncontrolled flow of formation or completion fluids outside of the target zone.

Prior to re-entry, the integrity of the casing shall be verified. The accepted method of establishing integrity is a pressure test conducted to the highest anticipated surface pressure. In some circumstances (e.g. short time frame since previous test) other methods may be acceptable. If the well history indicates potential well integrity concerns then additional well data may be obtained by running casing inspection logs.

6 Pressure Containment Barriers and Barrier Verification

6.1 General

6.1.1 The barriers used in well construction are designed to prevent unintended fluid flow, protect useable quality groundwater, and protect the well from corrosive environments. For the purposes of fracture treatment containment, types of barriers include

- casing,
- liners,
- wellheads (and associated hangers/seal assemblies),
- geological,
- cement, and
- various mechanical devices such as downhole packers and liner-top packers.

6.1.2 A well barrier plan should be developed that identifies potential flow paths, the direction of flow, and the type and number of well barriers that prevent flow along each of these paths during each phase of the well construction process. Operators should create diagrams illustrating the well barriers in place for each operational phase of well construction. Fracture stimulation can result in some of the highest loads the well will experience even though only for a controlled short period of time in terms of the well life cycle; consequently, 6.2 focuses on barriers for fracture treatment containment. Additionally, see API 65-2 and API 90-2 for information on barriers for potential flow and managing annular casing pressure, respectively.

6.2 Overview

6.2.1 During the well design phase, the operational and environmental conditions that a barrier may be exposed to are identified. These conditions define the functional requirements for the selection of the barrier equipment. During the selection phase, these functional requirements are directly compared to the ratings of the equipment as defined by industry standards or technical specifications obtained from the manufacturer. Design improvements are made during planning and execution based on learnings from previous wells and availability of new technology.

6.2.2 Once the final casing string has been set, cemented, and the drilling rig released, the well construction as executed should be reviewed and a barrier analysis be performed prior to fracturing. A variety of short-term barriers may be employed during the completion phase, such as wellhead isolation tools and fracture strings.

6.2.3 There are three main types of barriers that provide for isolation of the useable quality groundwater from the fracture stimulation. They are geological barriers (sometimes referred to as rock-seals), cement barriers, and mechanical barriers. A description of each follows.

6.3 Geological Barrier

Geological barriers are formations that are structurally competent to contain adjacent formation fluid pressures, have low enough matrix permeability to block fluid flow, and are devoid of other types of flow paths such as natural fractures, fissures, and faults. Geological barriers surrounding oil and natural gas reservoirs serve to contain and trap hydrocarbons within reservoir formations, thus preventing the escape of oil and gas into other formations. When applying fracturing treatments to stimulate production from oil and gas reservoirs, geological barriers can also prevent the fracture pressure or fluids from escaping above the top of cement of the primary production casing. Completion engineers rely on geologic barriers in order to contain the energy generated during fracture operations.

6.4 Cement Barriers

6.4.1 General

6.4.1.1 A cemented annulus serves as one type of barrier used to restrict the inter-zonal or annular flow of fluids. The principles and processes for establishing and maintaining cement as a barrier are central to providing well integrity. The design of a cement system intended as a barrier element should be in alignment with the overall well objectives and should complement the broader framework of the barrier systems established for the well. Additional information related to barrier philosophy, functionality, installation, and verification is found in API 65-2 and API 96.

6.4.1.2 Within the fully constructed wellbore, specific locations should be isolated by a cement barrier. These locations may include:

- a) useable quality groundwater in the surface-hole section;
- b) useable quality groundwater found in the open-hole section beneath the shoe of the surface casing;
- c) potential flow zones found in the open-hole section beneath the shoe of the surface casing;
- d) zones containing corrosive fluids;
- e) intra-zonal locations between perforation clusters within the reservoir section in the case of cemented completions (not applicable to uncemented completions);
- f) locations in vertical portion of the wellbore above the kickoff point;
- g) a defined distance across and above known geological barriers;
- h) locations within the build section below the kickoff point and above the landing point.

6.4.1.3 The primary focus for the design, testing, and placement of the cement slurry should, as a first order of priority, center on establishing barriers to fluid migration in the wellbore locations listed above.

6.4.2 Designing Annular Cement Coverage and the Top of Cement Depth

6.4.2.1 General

The top of cement (TOC) is the location in the annulus between pipe and hole/pipe where the column of cement slurry reaches its shallowest point at the end of the primary cementing operation. The placement locations and the associated TOC depths for cement slurries are designed according to several objectives, factors, and contingencies as discussed below. In addition to applicable regulations and industry standards on the TOC location above potential flow zones and water source zones in wells to be hydraulically fractured, other design considerations such as preventing annular pressure buildup (APB) and sustained casing pressure (SCP) may apply.

6.4.2.2 Isolation of Water Zones

Useable quality groundwater should be isolated by cement that is suitable to prevent annular cross-flow of fluids between zones. When useable quality groundwater is exposed in surface casing holes, the TOC is at the surface and verified by a returned volume of cement slurry flowing out of the well during cement slurry placement. When useable quality groundwater is encountered deeper than the surface casing setting depth, they may also require cement coverage.

6.4.2.3 Isolation of Potential Flow Zones

Potential flow zones are isolated using cement slurries and practices designed to prevent influx of fluids into the annulus. TOC selection and cement slurry design should consider local or regional knowledge of potential flow zones that can result in SCP or adversely impact cement sheath quality, respectively. Consideration should also be given to the potential for fluid flow into the annulus from adjacent injection wells. The TOC is typically designed to be 200 ft to 300 ft measured depth above the highest potential flow zone or may be defined by applicable regulations.

6.4.2.4 Isolation of Production Zones

The design TOC should be estimated by engineering methods that take into account factors such as well path and architecture, fracture height/length growth, flow potential/transmissibility of formations above the reservoir, hole quality, ECD limits while cementing, mud displacement efficiency, etc.

In the absence of engineering guidance to indicate otherwise, the minimum cement height above a production zone to be hydraulically fractured should be 500 ft (152 m) measured depth above the highest point of the induced fracture. In the case of a horizontal well to be hydraulically fracture stimulated, unless otherwise indicated by an engineered evaluation, the minimum recommended cement height is 500 ft (152 m) measured depth above kickoff point. If an uncemented liner is run, the minimum cement height above the host casing shoe should be 500 ft (152 m) measured depth. The 500 ft (152 m) measured depth minimum recommended cement height may be extended to improve cement isolation depending on specific well conditions such as build rates used above the last planned fracture in curve, whether an intermediate casing string has been set, or presence of a known geologic seal. The designed TOC must conform to applicable regulations.

6.4.2.5 Industry Standards

Besides regulations and industry standards on the TOC location above hydrocarbon zones or groundwater, industry standards recommend TOC locations for other reasons such as preventing APB and/or SCP. See API 65-2, API 90-2, and API 96.

6.5 Mechanical Barriers

The design of mechanical sealing devices being used as a well barrier is addressed in the sections below, in other parts of this document and in other API publications, including API 65-2 and API 96. The design of any mechanical well barriers should be performed in accordance with the objectives of the overall well barrier plan as discussed above. When utilizing mechanical barriers, the equipment should only be installed and operated in accordance with the manufacturer's recommended practice and other industry standards relating to the design, selection, and placement of barrier devices and barrier installation equipment. For packers that are to be used as fracture containment, the loads that these packers will be subjected to and their performance ratings should be documented in the basis of design.

The operator, in cooperation with the manufacturer, may elect to confirm the operating envelope of equipment through additional qualification testing. Equipment qualification methods may include finite element analysis and/or static and dynamic testing of entire components, sub-components, or material billets. Additional qualification tests can be necessary in those cases where the operator wishes to verify that the equipment satisfies the functional requirements of a particular well application.

6.6 Barrier Verification

6.6.1 Acceptance Criteria

Acceptance criteria should be established for the verification of each barrier in the well. The levels of acceptance may result in classification of the barrier as being verified, either as a tested or a confirmed barrier. Acceptance criteria define the conditions to be fulfilled to verify the integrity of the barrier for its expected application. Barrier verification results should be retained as required by local regulations or by company policy.

6.6.2 Geological Barrier Verification

Verification of geologic barriers is subject to interpretation and cannot be directly confirmed. Listed below are some examples of confirmation methods:

- a) mechanical testing of cores taken in field or well;
- b) log analysis;
- c) offset well information;
- d) pressure testing in vertical or near vertical well early in life of field;
- e) microseismic testing to establish field barriers;
- f) chemical or radioactive tracers.

6.6.3 Cement Barrier Verification

6.6.3.1 Successful placement of properly designed cement slurry can create a reliable annular barrier. However, verification of this cement barrier cannot be achieved directly through pressure testing in the direction of potential flow and to the anticipated loads.

6.6.3.2 Verification that a cement barrier has been established may be determined by either direct or indirect operational/design indicators or a combination of both. These indicators may include the following.

- a) The anticipated surface pumping parameters (density, rate, volumes, pressures, etc.) were met, confirming the cement operation was executed as planned.
- b) The anticipated circulation of fluids during cementing placement was maintained.
- c) FIT or LOT values are within the expected range upon drill out.
- d) Casing was centralized as planned.
- e) Casing was rotated or reciprocated during cement placement as planned.
- f) Measured differential pressure of the fluids just prior to bumping the plug is consistent with expected values.
- g) Isolation is confirmed from cement sheath evaluation logs.
- h) No indications of fluid influx occurs prior to, during, or after the cementing operation.
- i) Laboratory tests conducted under simulated downhole temperature and pressure conditions with representative field-blended cement and field sampled additives/mix water indicate the performance

design targets for the cement system were met. Additionally, unexpected surface treating pressure anomalies experienced during fracturing operations can indicate issues with quality cement job.

6.6.3.3 As described in API 65-2, once set, cement is considered a physical barrier element only when it has attained a minimum sustained compressive strength of 50 psi (345 kPa) in laboratory testing.

6.6.4 Mechanical Barrier Verification

6.6.4.1 The reliability of any well barrier is best verified if its sealing integrity is tested to expected loads in the direction of potential flow. However, pressure testing often cannot be used to verify a barrier's sealing integrity because potential load directions cannot be simulated within the well. If a mechanical well barrier cannot be verified by pressure testing in the direction of potential flow and to its full range of anticipated loads, consider one of the following alternative verification methods.

- a) Confirm the barrier's placement in the proper position in the well.
- b) Collect data or observations during installation of the physical barrier to confirm effective execution of the installation.
- c) If feasible, perform post-installation inspection of the mechanical barrier such as wellhead and liner-tops.
- d) If placement of a physical barrier cannot be confirmed, additional processes or procedures such as a monitoring plan may be used to enhance the well system barrier reliability in accordance with local regulations.

6.6.4.2 If a mechanical barrier is found to be deficient during the course of operations and it cannot be repaired, reassess the remaining well barrier system reliability in accordance with regulations. The loss of a mechanical barrier may cause a reduction in the well reliability. As a part of the management of change (MOC) process, consider replacing the mechanical barrier if possible, or installing supplemental mechanical barriers, or using operational barriers. Additional information concerning mechanical barrier verification is contained in API 96.

6.6.5 Special Consideration: Critical Separation Wells

6.6.5.1 General

Critical separation wells are wells where the zone to be fracture stimulated is close to the base of useable quality groundwater. These wells require additional review to determine if adequate barriers are in place to protect useable quality groundwater. Such separation wells can include one or more of the following characteristics:

- a) the vertical distance between base of useable quality groundwater and the zone to be fracture treated is less than 1000 ft (305 m);
- b) the geology between the base of the useable quality groundwater and zone to be fracture treated is complex and thereby there may not be an adequate barrier to protect the useable quality groundwater;
- c) wells where local regulatory agencies or local knowledge indicate that there may not be an adequate barrier.

6.6.5.2 Verification Considerations

For critical separation wells, the operator should perform an additional technical review early in the field development and gather additional data to verify adequate fracture treatment barriers,

The following are some mitigation measures that, where applicable, may be implemented to provide protection of useable quality groundwater for critical separation wells.

- a) Cement brought inside the surface casing or last casing shoe set protecting useable quality groundwater and cement allowed to set and develop 500 psi (3447 kPa) compressive strength before any additional casing movement or casing pressure test is performed (casing can be tested prior to the cement setting; see 5.3.5).

NOTE By bringing cement above the useable quality groundwater, the protective casing shoe prevents monitoring this casing shoe during fracture stimulation. Refer to local regulations concerning annulus pressure monitoring during fracture stimulation operations.

- b) Implement recommended cementing practices noted in 7.2 such as hole cleaning, pipe movement, and centralization.
- c) A cement evaluation tool should be run to assess radial cement integrity on the first few wells in the field.
- d) Fracture design and modeling should be performed to estimate fracture growth relative to this separation for the first few wells in the field.
- e) Three-dimensional fracture mapping methods such as microseismic monitoring on first test well(s) in the area to model barriers and fracture containment.
- f) During job execution, closely monitoring fracture pressures for variances (low or high) from plan and the job immediately suspended if the pressures vary from the pre-job defined values and not resumed until the cause of the pressure deviation is determined and a remediation plan is developed.
- g) Tracers or other surveillance methods can be used to identify the top of the fracture treatment.
- h) Use alternative stimulation techniques.

7 Cementing

7.1 General

7.1.1 Wells that are hydraulically fractured require appropriate levels of engineering design in order to establish an isolated wellbore. Guidance for zonal isolation practices and requirements for cement design, testing, and placement is found in API 65-2. Additional guidance can be found in industry recognized sources such as the Society of Petroleum Engineers (SPE), the International Association of Drilling Contractors (IADC), and from best practices established by service companies and operators.

7.1.2 Additionally, consideration should be given to those actions required to isolate the wellbore in a horizontal environment. In a horizontal completion, the production casing is isolated, usually with cement, in a range of well deviations from horizontal to vertical. The ability to establish adequate zonal isolation is impacted by the variation in deviation across the well trajectory. Careful consideration should be given to achieving adequate casing standoff, in order to promote mud displacement with cement in the vertical, deviated, and horizontal sections of the wellbore. The objective of this phase of the well construction is to produce a cemented annulus capable of containing the hydraulic fracturing treatment within the intended interval.

7.1.3 Operators should also recognize that operations conducted for a specific purpose in one section of the well can have unintended consequences in another part of the well. Furthermore, even those activities being conducted outside the wellbore, such as the impact of offset well operations, shall be managed during the drilling and cementing phase of well construction.

7.2 Pre-job Considerations

7.2.1 Hole Cleaning Considerations

Hole cleaning is important to achieve effective cuttings and gas removal and to maximize mud mobility. The hole should be conditioned before tripping out to run casing and again when casing is on bottom before cementing.

Hole cleaning in horizontal wells is more challenging due to solids settling, higher ECD, and eccentric tubulars. Additional drilling practices are needed to manage the formation of solids beds. Horizontal wells can require significantly longer circulation periods compared to more vertical wells in order to maximize mud mobility.

7.2.2 Casing Centralization

Effective pipe centralization is a critical component in achieving successful cement placement and the extent of centralization and its effect on fluid placement should be modeled.

7.2.3 Casing Movement

The use of pipe movement (reciprocation and/or rotation) during casing placement assists in achieving effective bulk drilling fluid removal. Pipe movement significantly improves the probability of flow being achieved on all sides of the annulus. While reciprocating pipe aids in the drilling fluid removal, it also imparts certain swab and surge pressures in the well that can lead to fluid influx or losses respectively. Computer simulation can be used to estimate such swab and surge pressures to enable their management within acceptable bounds. The results of these simulations then provide guidance on maximum allowable reciprocation rates that will prevent such losses or influx from occurring.

Additionally, industry studies have demonstrated that pipe rotation achieves better fluid displacement than reciprocation alone. Depending on well conditions, rotational rates of 5 rpm to 40 rpm have proven extremely effective in improving mud removal. In terms of actual execution, the use of reciprocation and rotation present certain operational challenges. When reciprocating pipe, it is important that the pipe does not become stuck in a position that prevents it from properly landing out in the wellhead at the end of the cement job. It should be noted that under certain conditions that pipe reciprocation is not achievable. The ability to rotate pipe may also be restricted by, for example, the amount of torque that can be applied may be a limiting factor. Torque limitations may be due to the casing connections themselves, running tools, or the rig equipment. In order to impart rotation on full casing strings, a rotating cement head would be required. Liners are often suitable candidates for rotation, but only if a rotating liner hanger has been specified.

7.2.4 Cement Slurry Design and Testing Parameters

7.2.4.1 The well construction objectives determine the detail of cement coverage and performance requirements for each hole section. The typical cement performance areas to which close attention is given during the design and testing process include (but are not limited to) gas control, static gel strength development, fluid loss, free fluid, slurry stability, thickening time, rheology, and the developed cement compressive or sonic strength. The mechanical parameters of the set cement will also be an important consideration in maintaining the cement barrier under the loads induced by changes in temperature and pressure during the hydraulic fracturing operations.

7.2.4.2 Operators should evaluate fluid flow potential during the well planning and drilling phase, in order to address the potential for fluid flow into the cemented annulus. If the intervals exposed during drilling of the borehole are capable of producing flow after cementing, contingency plans should be developed to use cement designs incorporating fluid control technologies. This includes gas-containing intervals in the shallower sections of the well and charged injection intervals, and it may extend into the hole section covered by the surface casing. Post-cementing operations such as pressure testing casing, slacking off casing and setting casing slips, drilling out of casing, etc. should also be accounted for in the impact on post-cement setting and prevention of creating potentially conductive channels.

7.2.4.3 Operators should identify those intervals within the drilled hole section that have the potential for flow. Zones with flow potential, either identified by predrilling methods or that flow during drilling, 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.

7.2.4.4 The process elements and considerations related to cement slurry design, testing, and placement are listed below and described more in-depth in API 65-2. These elements are as follows:

a) cement slurry thickening time;

b) cement slurry free fluid;

NOTE It is important to prevent a high-side fluid channel in the horizontal section.

c) cement slurry fluid loss;

d) cement slurry stability;

e) cement compressive strength;

f) cement slurry static gel strength;

g) cement pre-flush (wash) and spacer design;

h) cement slurry fluid velocity;

NOTE Fluid velocity may be limited in horizontal sections of wells compared to vertical sections due to increased ECD.

i) fluid rheology/density hierarchy.

NOTE In highly deviated or horizontal sections, designing for effective rheology hierarchies supersedes the density hierarchies as the critical placement parameter regardless of the cement densities that are being used.

7.2.5 Cement Placement and Thermal Modeling

7.2.5.1 Computer-based cement placement simulators and thermal models allow the cement design engineer to optimize the cementing operation in terms of the fluid hierarchy, the fluid pump rates, the casing centralization/mud displacement, and the cementing test temperature(s). These models eliminate the need for users to depend on inexact rules of thumb and provide assurance and continuity across the cement design process. A wide range of industry models are available, but variation in the computational complexity and functional capability exists in the currently available well engineering software that is used. These models are engineering tools; users should recognize the capabilities and the limitations of each model and apply sound engineering judgment in their application.

7.2.5.2 Typical modeling capabilities include the following.

a) Hydraulic simulations to predict the ECD during placement and equivalent static density (ESD) after the cement is in place. This modeling is performed to determine if the wellbore pressures during and after cement placement are within the pore pressure/fracture gradient window of the hole section and to allow the designer to make necessary adjustments to achieve this objective. ECD management during cement placement in a horizontal wellbore may be challenging, especially the case in smaller hole size/casing configurations (i.e. 6.75-in. hole × 4.5-in. casing). See API 65-2 for additional information concerning ECD modeling.

b) Dynamic surface pressure predictions.

c) Foamed cementing calculations (as applicable).

d) Calculation of the resulting casing swab and surge pressures.

e) Centralization/standoff calculations.

f) Efficiency and achievement of mud displacement.

- g) Circulating and post-cementing operation temperature profiles. In cases of highly deviated and horizontal wells, the test schedules in API 10B-2 cannot be used.

7.2.5.3 Wellbore stress modeling can also be used to evaluate the cement performance under the pressure and temperature changes imposed by the anticipated hydraulic fracturing operation(s).

7.3 Cementing Operations

7.3.1 Surface observations made both during and after placement of the cement can be used to establish confidence in the quality of the isolation provided by the cement sheath. This entails verification that the operation was executed and met the proposed targets as planned. These parameters include (but are not limited to) the following.

- a) The cement slurry performance has been verified by laboratory testing under representative well conditions and meets the desired design criteria.
- b) The centralization program was followed as planned in the job design.
- c) The volume of returns are as planned or modeled, with no unexpected loss of fluid returns observed or indications of fluid influx prior to, during, or after cement operations.
- d) Proper concentration of cement additives were used.
- e) The planned fluid pumping schedule for the job was followed.
- f) Deviation occurred from the cementing plan, such as an inability to maintain the desired cement slurry and spacer density, or the use of less-than-designed volume.
- g) The measured mud and cement properties [plastic viscosity (PV), yield point (YP), gels] are similar and representative of those that have been used in the pre-job modeling.
- h) Deviation occurred in the calculated versus measured differential pressure profile of the cement just prior to bumping the plug.
- i) The top cement plug is landed at the appropriate displacement volume.
- j) The float equipment holds.
- k) Where applicable, the liner hanger expanded successfully or liner-top packer set and tested.

7.3.2 In the above cases, where an exception to any of these criteria has been experienced, the establishment of an appropriate barrier(s) can be in question and further assessment may be necessary. A contingency plan should be in place and implemented if an exception to the above criteria occurs during the mixing and placement of the cement slurry. A cementing operation conducted that generally follows the parameters identified above can be considered to have produced a barrier when a sustained 50 psi (345 kPa) unconfined compressive strength has been reached.

7.4 Cement Sheath Evaluation

Caution should be exercised when using cement evaluation logs as the primary means of establishing the hydraulic competency of a cement barrier. The interpretations of cement evaluation logs are based on inferences from downhole measurements, and as such the interpretation of cement evaluation logs can be highly subjective. Refer to API 10TR1 for an overview of the attenuation physics, features, and the limitations of the various types of cement evaluation logs.

8 Fracturing Design Considerations

8.1 General

In order to perform hydraulic fracturing operations, treatment fluids are pumped into the well at rates and pressures that result in the creation of a hydraulic fracture. The potentially unfavorable consequences of loss of well integrity and/or fracture height growth can be avoided using suitable approaches to job design and execution. In the early phase of planning, a conservative design should be generated based on appropriate and available basin data for the targeted formation. This basic design is refined with rock property (log, core, permeability, porosity) and/or diagnostic fracture injection testing (DFIT) data acquired from early project wells (provided as input to modeling), which reduces the risks related to well integrity and uncontrolled height growth. This process allows for design modification and optimization as more well performance information and geologic data become available.

8.2 Fracture Stimulation Objectives

Fracture stimulation design is intended to enhance the well performance and to achieve economic success from improved production rates and ultimate reserves recovery. As such, the initial design will have a suite of goals such as achieving a particular fracture geometry and flow capacity: fracture half-length, width, height, and conductivity.

8.3 Fracturing Simulations

Computer modeling should be used to simulate fracturing operations to better understand the potential injection pressure behavior of the desired fracture geometry. When it is impractical to do so for every individual well, it may be performed for a group of wells, as long as they have similar formation lithologies, treatment schedules, and wellbore properties (i.e. a baseline generic model). When a fracture treatment is not reasonably represented by a preexisting model, then the design should be based on the available data or conservative estimates.

8.4 Design and Other Considerations

While enhanced production rates and improved resource recovery are the goals of fracture stimulation, safety is of the utmost importance. In line with safety, sustained well integrity and fracture height containment are considerations that can directly affect the stimulation design. In addition, a preliminary fracturing treatment design should consider personnel requirements, measures to protect human health and the environment, location size, on-site storage capability, pumping equipment needs, stimulation material selections (including fluid compatibility), and perforating plans. This preliminary treatment design is a primary input to the well basis of design, as the well construction and completion shall be designed to withstand the pressure and temperature changes that will take place during the fracturing treatment. Once the well has been constructed and the formation parameters are defined more accurately, a final fracturing treatment will be designed and modeled. This model can be verified and used as a basis of design for future stimulations in the field and the preliminary treatment design should take into consideration.

8.5 Formation Parameters (Uncertainties)

8.5.1 Understanding the geomechanical properties of a reservoir, and the adjacent zones, is one of the key data requirements for designing, executing, and maintaining zonal isolation. Since a fracture will take the path of least resistance, understanding the initial stress profile in the field is very important. A general understanding of the regional stress field is also important, since faults and other geological features can influence the amount and direction of the stresses laterally. Defining the barriers associated with fracture containment is of prime concern. The strength of a barrier is dependent on its stress in contrast to the other layers and specifically to the potential producing (target) layer. The thickness of a barrier and its various rock properties, such as Young's modulus and Poisson's ratio, will determine the depth of penetration into the barrier. This in turn will determine the upper barrier that will contain the fracture.

8.5.2 Analysis of previous fracture treatments is often the way of assessing this information. Pressure data acquired during the treatment may indicate whether the fracture has a confining barrier or not, including whether or not the barrier is being penetrated. Intersection of the fracture to natural fractures and faults may also be detected with the pressure data.

8.5.3 Various types of logging can be useful in gathering rock mechanical properties data such as Young's modulus, Poisson's ratio, and stress anisotropy values. Acoustic or sonic logs are used to obtain "dynamic" rock properties. These are different from the "static" rock properties measured in the labs. Typically, logs are calibrated with core test data from the lab. Core data from the reservoir and the bounding layers should be included for proper calibration. The data acquired during the fracturing treatment will validate and calibrate the stress profile and mechanical earth model.

8.5.4 Defining the uncertainty ranges of influential formation parameters (quality data, reasonable analogue, etc.) results in more robust estimates of the treating pressures and estimate of created fracture geometry. An understanding of a range of formation properties such as rock stress profile, Young's modulus, reservoir pressure, Poisson's ratio, and the presence and properties of natural fractures is important to create an appropriate fracture design. The modeling design can be as simple as a three-layer model (reservoir layer with upper and lower barriers) or as complex as a multi-layered model with well-defined layer properties. The input data to the model directly affects the expected behavior of fracture initiation, extension pressures, and estimate of geometry. If the anticipated pressures or height growth are a concern, then risk mitigations should be considered by directly altering the controllable fracture design parameters (decisions) as discussed below.

8.6 Controllable Fracture Design Parameters (Decisions)

8.6.1 One of the key fracture design considerations that operators can precisely control is the fracturing fluid. Fracturing fluids have

- different rheological properties (slick water, linear gels, crosslinked gels, visco-elastic surfactants, etc.), including considerations for how base fluid water quality affects these properties;
- different densities (water-based, oil-based, energized, foamed, etc.); and
- different combinations of additives (proppants, friction reducers, breakers, crosslinkers, etc.).

8.6.2 These fluids will generate different fracture geometries and surface pressures. Fluid selection should be based on appropriate viscosity, proppant transport, and fluid leak-off control for the given temperature environment with minimal surface pumping pressure to create the desired fracture geometry. Fluid viscosity affects surface pumping pressure due to friction in the well and the fracture. Friction reducers or delayed crosslinkers can be used to reduce the magnitude of this friction and reduce the surface treating pressures. The effect of any restriction in the flow path, especially pipe size, on friction, and therefore on the maximum required wellhead pressure, can be significant.

8.6.3 Proppant selection is mainly influenced by stress tolerance, the dimensionless conductivity target and transport property of the fluid selected. The physical properties of the proppant, (e.g. angularity, density), characteristic of fluid type (e.g. viscosity, density, proppant pack damage, etc.), and pumping parameters (volumes pumped, mass of proppant, slurry concentration, and pump rate) will affect the resulting fracture conductivity and geometry. In addition, erosion, corrosion, and stress-corrosion cracking of the downhole equipment should be considered and appropriate mitigations implemented in order to prevent potential mechanical failure of the tubulars at load conditions less than those designed.

8.6.4 In cased and cemented completions, the location of the perforations in relation to stress barriers and the well trajectory directly affect the fracture geometry and treating pressures. Perforation parameters also influence injection pressures and fracture to wellbore connection. Due to the number of perforation combinations with differing stress profiles, the fracture propagation behavior is a complex nonunique solution. In open-hole completions, the complexity introduced by perforations in cemented cased hole is basically eliminated; however, a new set of complexities is introduced such as multiple fracture initiations, etc.

9 Fracturing Execution Considerations

9.1 General

Fracturing execution, especially management of pressure, shall be performed within the limits of the well construction basis of design. Executional failure, by allowing wellbore pressure to increase above the calculated allowable limits, can result in unfavorable consequences to the system well integrity and/or undesired fracture height growth. A properly executed fracture design requires close collaboration between the operating company and the many service providers and vendors. Fracture designs should be reviewed with information such as

- the indicated TOC,
- actual temperatures and fluid properties, and
- previous case history data.

These updated designs should subsequently be reviewed and approved by the operator and the service company. A job safety analysis should be conducted prior to the fracturing treatment, in order to appropriately identify the possible risks to the personnel and equipment on site. The risks identified should be reduced to an acceptable level through a combination of preventative and mitigating measures.

9.2 Completion Execution Objectives

Fracturing execution objectives are numerous; however, for the purposes of this discussion they include the following:

- a) performing well operations safely;
- b) retaining the stimulation treatment fluids within the wellbore and intended formation;
- c) retaining the produced fluids within the wellbore;
- d) providing optimal well performance allowing the well to deliver the projected production rate and reserves.

9.3 Surface Equipment Selection

9.3.1 Mixing and pumping equipment should be selected on the basis of the primary job parameters (volumes of fluid and proppant, type of fluids to mix, maximum expected pumping rate and pressure).

9.3.2 Wellhead isolations tools or a temporary fracture tree can be used to protect the production valves or the wellhead itself from damage resulting from proppant erosion/abrasion (see 5.9). High-pressure shutdown devices should be used to maintain a pressure safety margin and prevent damage to the system integrity (e.g. kick outs, trips, pressure-relief systems, etc.).

9.3.3 Quality assurance and quality control should be conducted before and during the treatment. Instrumentation should be calibrated before the treatment begins. The mixing, blending, pumping, etc. equipment should be tested for proper operation. During the fracture treatment, tanks should be strapped, fluid levels should be visually monitored, and sacks of solid material should be tracked to verify instrumentation is working properly.

9.4 Pressure Monitoring and Management

9.4.1 The well operator, or the operator's designated representative, should be on site throughout the hydraulic fracturing treatment in order to verify that the fracture execution takes place in accordance with the program expectations. During the hydraulic fracture treatment, certain parameters should be continuously monitored. These parameters include, but are not limited to, surface injection pressure (psi), appropriate

annular pressure (psi), slurry rate (bpm), proppant concentration (ppa or ppg), fluid rate (bpm), and chemical additive rates.

9.4.2 In order to improve the accuracy of the hydraulic fracturing modeling, a data calibration test (mini-frac or DFIT) may be conducted. This can provide useful information such as the closure pressure, fracture extension pressure, and leak-off coefficient. Data from the calibration test helps the engineers and service companies to refine the fracture design and reduce the risk of fracturing out of zone.

9.4.3 Real-time pressure monitoring can provide an early indication of a screen-out, which can warrant the shutting off of proppant and initiating flush earlier than the original plan, in order to reduce high treating pressures. Pressures can increase rapidly, if treatment pump rate is increased, or a screen-out occurs. A suitable safety factor should be used in setting the maximum allowable treating pressure to protect people, equipment, and the environment. Systems are used for high-pressure fracturing pumps, which are activated by overpressure measuring devices that compare the actual pump pressure to the set pressure limitation for the pump, its discharge line to the wellhead, or the well itself. These systems are designed to provide for operating personnel safety and to prevent damage to equipment during fracturing operations.

9.4.4 Casing annuli that are not cemented to surface and are accessible shall be monitored during the hydraulic fracturing treatment. For additional safety consideration, a pressure-relief system may be used. The relief valve, if used, should be set so that the pressure exerted on the casing does not exceed the burst of external casing and collapse of internal casing (if exposed), or cause failure of the casing shoe.

9.4.5 During the execution of the hydraulic fracturing operation, if the treating pressure and/or annuli pressures deviate from anticipated pressures in a manner that indicates the mechanical integrity of the well has been compromised and continued operations pose a risk to personnel safety, equipment integrity, or the environment, the hydraulic fracturing operations should be immediately suspended and not resumed until the cause of the pressure deviation is determined and a remediation plan is developed.

10 Fracturing Model Optimization Considerations

In areas where previous fracture stimulation treatments have been performed, the data collected can be used to calibrate and further validate fracture treatment models. However, in areas of little to no previous fracture stimulations, additional data may be needed. There are several technologies available and in development to provide that data, where applicable. These include, but are not limited to, the following:

- a) surface and downhole treatment pressure measurements;
- b) well testing and production measurements;
- c) temperature logs or distributed temperature sensing (DTS);
- d) tracers logs;
- e) surface and downhole microseismic measurements;
- f) surface and downhole tiltmeters measurements;
- g) production logs;
- h) open-hole image logs;
- i) cross-dipole sonic logs.

Bibliography

- [1] API Specification 5B, *Specification for Threading, Gauging, and Thread Inspection of Casing, Tubing, and Line Pipe Threads*
- [2] API Specification 5CT, *Specification for Casing and Tubing*
- [3] API Recommended Practice 7G, *Recommended Practice for Drill Stem Design and Operating Limits*
- [4] API Recommended Practice 10B-2, *Recommended Practice for Testing Well Cements*
- [5] API Recommended Practice 10D-2, *Recommended Practice for Centralizer Placement and Stop Collar Testing*
- [6] API Technical Report 10TR1, *Cement Sheath Evaluation*
- [7] API Technical Report 10TR4, *Selection of Centralizers for Primary Cementing Operations*
- [8] API Recommended Practice 90-2, *Annular Casing Pressure Management for Onshore Wells*
- [9] API Recommended Practice 96, *Deepwater Well Design and Construction*
- [10] API Bulletin 100-3, *Community Engagement Guidelines*
- [11] SPE 54360-MS ¹, *A Comprehensive Monograph for Hydraulic Fracture Initiation From Deviated Wellbores Under Arbitrary Stress Regimes*, April 1999, M.M. Hossain, M.K. Rahman, and S.S Rahman
- [12] SPE 152596, *Hydraulic Fracturing 101: What Every Representative, Environmentalist, Regulator, Reporter, Investor, University Researcher, Neighbor and Engineer Should Know About Estimating Frac Risk and Improving Frac Performance in Unconventional Gas and Oil Wells*, February 2012, G. King
- [13] SPE 145949, *Hydraulic-Fracture-Height Growth: Real Data*, October 2011, K. Fisher and N. Warpinski
- [14] IADC ²/SPE 151470, *Special Considerations in the Design Optimization of High Rate, Multistage Fractured Shale Wells*, March 2012, C. Sugden, J. Johnson, M. Chambers, G. Ring, and P.V. Suryanarayana
- [15] SPE 125970, *Montney Unconventional Gas—Next Generation, An Integrated Approach to Optimizing Wellbore Completions Technology*, R.A. Schnell, N.C. Tapper, R. Genyk, D. Deliu, and H. Tavakol

¹ International Association of Drilling Contractors, 10370 Richmond Ave #760, Houston, Texas 77042, www.iadc.org.
² Society of Petroleum Engineers, P.O. Box 833836, Richardson, Texas 75083, www.spe.org.



AMERICAN PETROLEUM INSTITUTE

1220 L Street, NW
Washington, DC 20005-4070
USA

202-682-8000

Additional copies are available online at www.api.org/pubs

Phone Orders: 1-800-854-7179 (Toll-free in the U.S. and Canada)
303-397-7956 (Local and International)
Fax Orders: 303-397-2740

Information about API publications, programs and services is available
on the web at www.api.org.

Product No. G100101