

WORLDWIDE CEMENTING PRACTICES

First Edition, January 1991

American Petroleum Institute
1220 L Street, Northwest
Washington, D.C. 20005



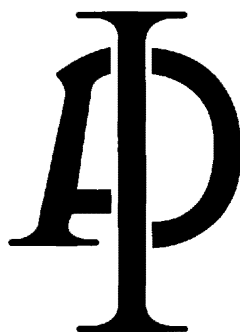
WORLDWIDE CEMENTING PRACTICES

Sponsored by

COMMITTEE 10
COMMITTEE ON STANDARDIZATION OF WELL CEMENTS

AMERICAN PETROLEUM INSTITUTE

SPECIAL BOOK PROJECT
API PROJECT 88-59
Dwight K. Smith - Project Leader



Published by
American Petroleum Institute
1991

REAFFIRMED, MAY 1995

Documents
Document Sharing Hub

Copyright 1991 by the
American Petroleum Institute

Printed in the U.S.A.
by
Johnston Printing Company
Dallas, Texas

POLICY

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

API is not undertaking to meet duties of employers, manufacturers, or suppliers to warn and properly train and equip their employees, and others exposed, concerning health and safety risks and precautions, nor undertaking their obligations under local, state, or federal laws.

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.

FOREWORD

Several thousand wells are drilled and completed annually throughout the world--some productive of oil or gas and some that are dry--yet during this drilling and completion process most of these wells are cased, with the casing set in the borehole, surrounded by cement.

In 1959, the API published the first edition of a book covering the technology of "Oil Well Cementing Practices in the United States" under the leadership of Harry N. Stansbury of the Atlantic Refining Co. Drilling and completion experts throughout the industry participated in this early project. Its contents covered cementing technology dating from the early 1920's through the mid 1950's. The major part of this cementing information, however, represented practices used after World War II until about 1956.

Since these early events in our industry, many changes have taken place in cement standardization, in cement testing, and in field practices, particularly in deep drilling. API Cement Standardization Committee 10 and its members have played a significant role in the research and development of all phases of cement technology since this original book was published. In 1987, experts within the industry and from Committee 10 were again selected to write chapters in this revised volume entitled "World Wide Cementing Practices." **This revised version is an attempt to mold all the various technologies used today; no part of this book should be interpreted as an American Petroleum Institute recommendation for any procedure, method, practice or equipment.**

In 1990 the processes of "cementing a well" are very similar in most parts of the world. Nomenclature and terminology may vary from one area to another; however, the basic process is about the same worldwide.

The compositions used in cementing today are essentially API cements or API cements prepared by supplementing with additives or by variations in grinding or manufacturing processes. Bonding and sealing materials other than Portland cement are rarely used in wells, yet when applied follow methods similar to those used with Portland cement.

Cementing of surface casing is one of the most uniformly followed procedures. Surface casing depth may vary from 100 to several thousand feet; its function is to protect freshwater formations, to mount wellhead equipment, and to anchor blowout-preventer equipment.

"Intermediate strings" may range from a few thousand to over 10,000 ft in depth. In some conditions they case off salt beds of moderate depth and are called "salt strings." In others they case off troublesome shales, or zones that will not withstand high fluid pressures, and for these purposes they may be called "protection strings."

"Completion strings" and/or liners represent more diversified designations. In localities where cement is used to enable such casing strings to shut off water immediately above the oil production, the term "water string" is customary.

In other areas the customary term is "oil string," and where the well may produce oil or gas or both, "completion string," "production string," "producing string," or "long string" may be used.

Where it becomes impractical to continue drilling to the depth intended for the producing string, it is sometimes set at a lesser depth as a protection string and the hole below is cased with a liner hung in the bottom of the original string.

Technology now being developed and evaluated in selected drilling areas may or may not find wide applications in the petroleum industry. Of particular interest is the drilling and cementing of horizontal wells. The use of this technology has been in fewer than 2000 of the 3.5 million wells drilled worldwide before 1990. Completion techniques in horizontal wells has been variable, yet experts will agree that the same cementing fundamentals are required as in a vertical or directional well, i.e., a well-drilled hole, proper centralization, mud conditioning to remove regions of gelled or immobile fluids before cementing, use of proper spacers and/or flushes, use of good cementing materials with emphasis on solids-settling control with no free water, and pipe movement where possible.

The chapters of this volume follow a logical sequence in relation to the development and application of cementing methods and consequently bear a fairly close relationship one to another. This relationship, however, is loose enough to permit the chapters to be read and studied individually. To facilitate such use, indexes are provided at the beginning of each chapter rather than at the back of the book.

Leadership in this major endeavor has been under API Cement Standardization Committee 10 chairman D. G. "Jerry" Calvert, Mobil Oil Company in Dallas, TX, and coordinated for Committee 10 by Dwight K. Smith, Consultant (Ret. Halliburton Services), Duncan, OK.

ACKNOWLEDGMENT

Development of the volume *Worldwide Cementing Practices* has involved many people and organizations. So many individuals and groups of people helped in the development of the book, and in so many ways, that its publication can truly be said to be a consequence of industry effort.

Individuals, particularly, contributed freely of their time and effort and they and their employing companies are due more than a small measure of credit for this volume. Among them are the past and present chairmen and secretaries of API Committee 10 who provided the leadership for the development of much of the original material and the expert review for individual chapters.

Chapter Authors - Co-Authors

Sam Maravilla - Consultant (Ret. Lehigh Portland Cement Co.)
Richard Gandy - BJ-Titan Co.
R. C. "Bob" Smith - Consultant (Ret. Amoco Production Co.)
Bob Sullaway - Halliburton Services
Fred Brooks - Consultant (Ret. Exxon Production Research Co.)
W. H. "Hal" Grant Jr. - Chevron Research Co.
H. E. "Ed" Lindsey - Lindsey Completion Systems
Mike Cowan - Shell Development Co.
Ben Bradford - Consultant (Ret. Dowell-Schlumberger)
Charles R. George - Halliburton Services
T. R. Garvin - Halliburton Services
Larry K. Moran - Conoco Inc.
K. J. Goodwin - Mobil E&P Services Inc.
W. W. Carpenter - Schlumberger Well Services Inc.
D. G. "Jerry" Calvert - Mobil E&P Services Inc.
R. L. Root - Dowell-Schlumberger
Dwight K. Smith - Consultant (Ret. Halliburton Services)

API Cement Standardization Committee 10 (1951-1990)

Chairmen

Carl Dawson - 1951 through 1955 - Standard Oil of California
Walter F. Rogers - 1956 through 1960 - Gulf Oil Company
George Howard - 1961 through 1962 - Stanolind Oil and Gas Co.
Francis M. Anderson - 1963 through 1967 - Halliburton Oil Well Cementing Co.
Bill Bearden - 1968 through 1970 - Pan American Petroleum Co.
R. V. "Bob" Scott - 1971 through 1975 - Standard Oil of California
Frank Shell - 1976 through 1978 - Phillips Petroleum Co.
Horace Beach - 1979 through 1981 - Gulf Oil Company
R. C. "Bob" Smith - 1982 through 1984 - Amoco Production Co.
Dwight K. Smith - 1985 through 1987 - Halliburton Services
D. G. "Jerry" Calvert - 1988 through 1990 - Mobil E&P Services Inc.
Hal Grant - 1991 through 1994 - Chevron Petroleum Co.

Secretaries

Walter F. Rogers - 1951 through 1955 - Gulf Oil Co.
N. C. Ludwig - 1956 through 1961 - Universal Atlas Cement Co.
J. B. Alexander - 1962 through 1967 - Southwestern Portland Cement Co.
Sam Maravilla - 1968 through 1987 - Lehigh Portland Cement Co.
Charles R. George - 1988 through 1994 - Halliburton Services

Some of the organizations from whose literature and resources illustrative material has been freely taken are as follows:

SPE Monograph "Cementing"
Halliburton Services
World Oil Magazine
Dowell-Schlumberger
Petroleum Engineer Magazine
Oil and Gas Journal
Lindsey Completion Systems

To all these people and organizations and to many others who have not been identified, the American Petroleum Institute owes a debt of gratitude.

It is the hope of API Committee 10 that these few words will express that gratitude, and in part, repay that debt.

Bobby Hall - Director API, Dallas, Texas
Mark Rubin - API Staff, Dallas, Texas
Mike Loudermilk - API Staff, Dallas, Texas
Jim Giddens - Halliburton Services, Duncan, Oklahoma
Caterina Mathes - Halliburton Services, Duncan, Oklahoma
Walt Glover - Halliburton Services, Duncan, Oklahoma

TABLE OF CONTENTS

	PAGE
Chapter 1 - Cementing History and the Development of API Well Cement Standards Sam Maravilla Richard Gandy	2
Chapter 2 - Cement Job Planning R. C. (Bob) Smith	18
Chapter 3 - Casing Equipment Bob Sullaway	33
Chapter 4 - Primary Cementing Fred Brooks W.H. Grant Jr.	52
Chapter 5 - Liner Cementing E.H. Lindsey	70
Chapter 6 - Remedial Cementing K.M. Cowan Ben B. Bradford	82
Chapter 7 - Down-hole Plugging Charles George	103
Chapter 8 - Lost Circulation: Its Consideration During Primary Cementing Larry Moran Thomas Garvin	115
Chapter 9 - Cement Sheath Evaluation K. J. Goodwin W. W. Carpenter	126
Chapter 10 - Special Cementing Conditions Jerry Calvert Ron Root	149
APPENDIX A - Bibliography	170
APPENDIX B - Patents	211
APPENDIX C - Worldwide Field Data	229
APPENDIX D - Squeeze Cementing Formulas and Calculations	440
APPENDIX E - U.S. Wells Drilled 1859-1988	447
APPENDIX F - U.S. Drilling Record Depths to 1990	448
APPENDIX G - U.S. Record Producing Wells (Depths) to 1990	449
APPENDIX H - U.S. Drilling Depth Records by State to 1990	450
APPENDIX I - U.S. Record Producing Wells by State to 1990	452
APPENDIX J - U.S. Well Completions and Footage Drilled by Depth Intervals 1970-1989	454
SUBJECT-AUTHOR INDEX	461

Chapter 1

Cementing History and the Development of API Well Cement Standards

authors
Sam Maravilla
Richard Gandy

INDEX

SUBJECT	PAGE
1.1 Introduction	3
1.2 Early History of Portland Cement	3
1.3 Manufacture of Portland Cement	4
1.4 Chemistry of Cements	5
1.5 API Standardization Background	9
1.6 Publication of Standardization Studies	13
1.7 Current API Well Cement Classifications	13
1.8 Cement Properties Covered by API Specifications	14
1.9 Current and Future Development of API Standards for Well Cements	16
1.10 Summary	17

Chapter 1

Cementing History and the Development of API Well Cement Standards

By: S. Maravilla and R. Gandy

Sam Maravilla is a private consultant working out of Hammond, Indiana. He retired from Lehigh Portland Cement Co., Waco, TX, where he was director of research and development for well cements. From 1950 to 1980, Maravilla served as senior research scientist at the Gary, IN Central Research Laboratories for Universal Atlas Cement Division of US Steel where he authored several well cement patents. He has a BA degree in chemistry from the University of Indiana (1950) and is a member of API, SPE, ICMA, and ASTM. He was secretary of the API Committee 10 on standardization of well cements from 1968 to 1988, serving also as publications chairman during that period, and has been a member of more than 20 API task groups since 1959.

Richard Gandy is a group leader in cementing at BJ-Titan's research and development laboratory in Tomball, TX. He attended the University of Texas at Arlington, and has worked in cement technical services and R&D since 1958.

1.1 Introduction

The objectives of this chapter are (1) to review briefly the early history,* manufacture, and chemistry of Portland cement; (2) to review the history and development of American Petroleum Institute (API) standards documents; (3) to discuss publication of well cement standardization studies; and (4) to discuss present API standards.

1.2 Early History of Portland Cement¹

Portland cement is produced by partially fusing powdered blends composed of limestone with materials such as clays, shales, blast furnace slag, siliceous sands, iron ores, pyrite cinders, etc. From a chemical standpoint these blends may be considered to be mixtures of the oxides of calcium (CaO), aluminum (Al_2O_3), silicon (SiO_2), magnesium (MgO), iron (Fe_2O_3), potassium (K_2O), and sodium (Na_2O). During heating to temperatures of about 2700°F , these oxides combine to form calcium silicates and aluminates (commonly referred to as "clinker") that can react with water to form a hydrated product which has cementitious properties. The paste of Portland cement and water will harden under water as well as in air. Because this paste can set under water, Portland cement is known as a hydraulic cement.

When hydraulic cements set and harden by reacting chemically with water, this reaction, called hydration, forms a stonelike mass. Hydration begins as soon as cement comes in contact with water. Each cement particle forms a type of growth on its surface that gradually spreads until it links up with the growth from other cement particles or adheres to adjacent substances. This building up results in progressive stiffening, hardening, and strength development. The stiffening of well cement slurries can be recognized by an increase in consistency that is dependent on time, temperature-pressure conditions, and upon the composition and fineness of the cement and slurry formulation.

Early investigators found that limes produced by calcining certain limestones had the property of setting and hardening under water; in other words, they were hydraulic limes. These limestones were found to contain relatively large amounts of argillaceous materials, i.e., clays and shales. From this experience with hydraulic limes the practice developed whereby Portland cements were made by heating blends of high grade limestones with other materials to give the desired proportions of CaO , Al_2O_3 , SiO_2 , and Fe_2O_3 in the finished product. This blending of separate materials was done by English Engineer Joseph Aspdin in 1824; he gave the name "Portland cement" to his product because the concrete produced from it resembled in appearance the building stone quarried on the Isle of Portland. From this begin-

*Much of the literature cited in this chapter consists of reviews from which the reader may obtain references to the earlier literature.

ning, the present-day Portland cements developed over many years.

Although Aspdin was the first to prescribe a formula for Portland cement and the first to have his product patented, calcareous cements had been used for many centuries. Natural cements were manufactured in Rosendale, New York, in the middle 1800's.² The first recorded shipment of Portland cement to the United States was in 1868 and the first Portland cement made in the United States was produced at a plant in Coplay, Pa., in 1871.

In the early development of Portland cement, it was found that cement clinker, when powdered and mixed with water and aggregate, produced mortars and concretes that were very difficult to place because of the rapid rates at which they stiffened and became unworkable. There appears to be no record of the discovery, but someone found about a century ago that this rapid stiffening could be prevented by either grinding the clinker with or blending the powdered clinker with small amounts of either gypsum or plaster of Paris ($\text{CaSO}_4 \cdot \frac{1}{2}\text{H}_2\text{O}$). This use in the United States³ developed from an American observing masons in Paris adding plaster of Paris to Portland cement mortars. It seems, therefore, that the discovery that calcium sulfate compounds would retard the rate of stiffening of Portland cement pastes may have been the result of accidentally mixing plaster of Paris and Portland cement in the same equipment without cleaning between batches.

The first methods⁴ of testing hydraulic cements for strengths and setting times were developed, beginning in about 1750, for use with hydraulic limes and blends of limes with pozzolans. This work on test methods led gradually to specifications for Portland cements. Since gypsum was ground with the clinker to control setting times, and since it was observed that calcium sulfate in excess of certain amounts produced excessive expansions in the cement products, it was natural that these specifi-

cations should include maximum limits for the SO_3 content of Portland cement. The first specification for Portland cement appears to be one adopted in Germany in 1878. This specification did not include a limit for SO_3 until 1909, when the limit was set at 2.5%.

In 1940 ASTM (American Society for Testing Materials) Committee C-1 on Portland cement adopted specifications (C 150-40T) for five types of Portland cement: Types I, II, III, IV, and V. This specification has been reviewed a number of times and the current revision C150-86 carries the limits of 3.0, 3.0, 3.5, 2.3, and 2.3% respectively for the SO_3 contents of Types I, II, III, IV, and V cements when the potential tricalcium aluminate contents do not exceed 8%. When the tricalcium aluminate contents exceed 8%, the SO_3 content of Type I cement may not exceed 3.5%, and that of Type III may not exceed 4.5% (Table 1.1).

As may be seen from Table 1.1, API Classes B, C, D, E, F, G, and H have a C_3A content of about 8% or less and are similar in composition to ASTM Type II, which may possess either moderate or high sulfate resistance. However, C_3A requirements for API Class C HSR cement are more stringent than the ASTM Type III HSR cement based on 1954 studies reported by Swayze.⁵

1.3 Manufacture of Portland Cement

Portland cement is produced by pulverizing clinker consisting essentially of hydraulic calcium silicates, along with some calcium aluminates and calcium aluminoferrites, and usually containing one or more forms of calcium sulfate (gypsum) as an interground addition.

Materials used in the manufacture of Portland cement must contain appropriate proportions of calcium oxide, silica, alumina, and iron oxide components. During manufacture, all materials are analyzed frequently to ensure a uniformly high quality cement.

**TABLE 1.1—COMPARISON OF ASTM PORTLAND VS API WELL CEMENT
 SO_3 AND C_3A REQUIREMENTS**

	Sulfur Trioxide (SO_3) max., %	Tricalcium Aluminate (C_3A) max., %
ASTM Type I	3.0	---
API Class A, Ordinary (O) (Similar to Type I)	3.0	---
ASTM Type II	3.0	8
API Class B, D, E, F, G, H Moderate Sulfate Resistance (MSR) (Similar to Type II)	3.0	8
ASTM Type II	---	---
API Class B, D, E, F, G, H High Sulfate Resistance (HSR) (Similar to Type II)	3.0	3.0
ASTM Type III	4.5	15
API Class C Ordinary (O) (Similar to Type III)	4.5	15
ASTM Type III High Sulfate Resistance	3.0	5
API Class C High Sulfate Resistance (HSR) (Similar to Type III)	3.0	3



TABLE 1.2—SOURCES OF RAW MATERIALS USED IN MANUFACTURE OF PORTLAND CEMENT⁵

Lime, CaO	Iron, Fe ₂ O ₃	Silica, SiO ₂	Alumina, Al ₂ O ₃	Gypsum, CaSO ₄ •2H ₂ O	Magnesia, MgO
Alkali waste	Blast-furnace flue dust	Calcium silicate	Aluminum-ore refuse*	Anhydrite	Cement rock
Aragonite*	Clay*	Cement rock	Bauxite	Calcium sulfate	Limestone
Calcite*	Iron Ore*	Clay*	Cement rock	Gypsum	Slag
Cement-kiln dust	Mill scale*	Fly ash	Clay*		
Cement rock	Ore washings	Fuller's earth	Copper slag		
Chalk	Pyrite cinders	Limestone	Fly ash*		
Clay	Shale	Loess	Fuller's earth		
Fuller's earth		Marl*	Granodiorite		
Limestone*		Ore washings	Limestone		
Marble		Quartzite	Loess		
Marl*		Rice-hull ash	Ore washings		
Seashells		Sand*	Shale*		
Shale*		Sandstone	Slag		
Slag		Shale*	Staurolite		
		Slag			
		Traprock			

NOTE: As a generalization, probably 50% of all industrial byproducts have potential as raw materials for the manufacture of portland cement.

*Most common sources.

Steps in the manufacture of cement are illustrated in the flow charts in Figs. 1.1 and 1.2.⁶ While the operations of all cement plants are basically the same, no flow diagram can adequately illustrate all plants. There is no typical Portland cement manufacturing plant; every plant has significant differences in layout, equipment, or general appearance.

Selected raw materials (Table 1.2) are crushed, milled, and proportioned in such a way that the resulting mixture has the desired chemical composition. The raw materials are generally a mixture of calcareous (calcium oxide) material such as limestone, chalk or shells, and an argillaceous (silica and alumina) material such as clay, shale, or blast-furnace slag. Either a dry or a wet process is used. In the dry process, grinding and blending are done with dry materials. In the wet process, the grinding and blending operations are done with the materials in slurry form. In other respects, the dry and wet processes are very much alike. Figure 1.2 illustrates important technological developments that can improve significantly the productivity and energy efficiency of dry-process plants.

After blending, the ground raw material is fed into the upper end of a kiln. The raw mix passes through the kiln at a rate controlled by the slope and rotational speed of the kiln. Burning fuel (powdered coal, oil, or gas) is forced into the lower end of the kiln where temperatures of 2600°F to 3000°F change the raw material chemically into cement clinker, grayish-black marble-sized pellets.

The clinker is cooled and then pulverized. During this operation a small amount of gypsum is added to regulate the setting time of the cement. The clinker is ground to such fine texture that nearly all of it passes through a No. 200 mesh (75 micrometer) sieve with 40,000 openings per square inch. This extremely fine gray powder is Portland cement.

1.4 Chemistry of Cements

During the burning operation in the manufacture of Portland cement clinker, calcium oxide combines with

the acidic components of the raw mix to form four compounds that make up 90% of cement by weight. Gypsum and other materials are also present. A typical oxide analysis, together with calculated compound composition of the four compounds of API Class G or H dry cement used in wells is given in Table 1.3.

The characteristic crystal shape of dry cement compounds observed under magnification and reflected light using an etched polished section specimen is illustrated in Fig. 1.3.⁷ Statements below are keyed by number to compounds shown in Fig. 1.3.

1. C₃S, tricalcium silicate (alite). Hexagonal or angular crystals may be highly colored with blues, pastels, and greens.

2. C₂S, dicalcium silicate (belite). Spherical or rounded crystals, often with rough surfaces and not highly colored.

3. C₄AF, tetracalcium aluminoferrite. White matrix surrounding other crystals.

4. C₃A, tricalcium aluminate. Gray blades, flecks, or streaks.

5. MgO, periclase. Small, pink hexagonal plates.

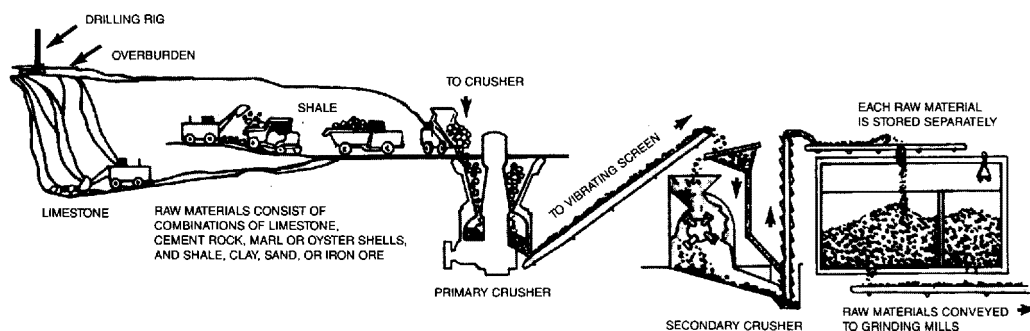
6. CaO, free lime. Small, smooth spheres, highly colored in reds, purples, greens, etc., generally in clusters.

7. Weathering, water, or moisture attack on outer edge of cement grains causes discoloration of affected crystals, sometimes caused by outdoor storage or shipping.

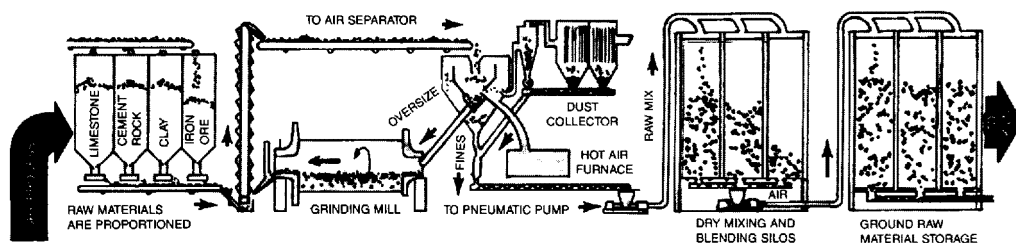
When cement is slurried at the wellsite, water functions as a carrier for placement of the reactive silicates produced in the manufacturing process. Once in place, a plastic lattice structure develops gel strength, finally resulting in a set solid mass (Fig. 1.4).⁸

A well-burnt API Class H dry cement is shown in Fig. 1.5A.⁹ The crystals are clear-cut, colorful, and correct in size and distribution. A poor-quality dry cement is illustrated in Fig. 1.5B.⁹ The color is drab, and individual particles are not distinct; this condition is caused by inadequate burning in the kiln during manufacture.⁸

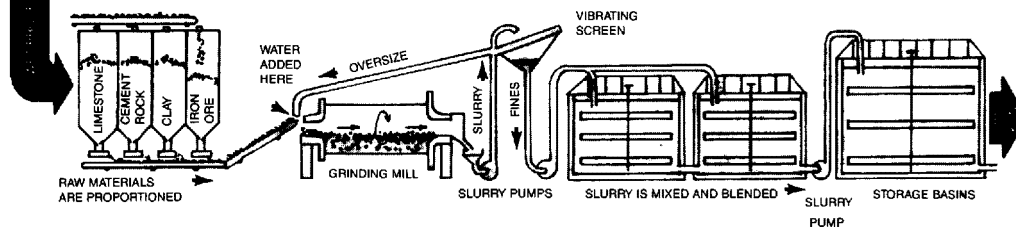
Investigators^{5,10} have disclosed a marked difference in the physical properties of Portland cement pastes



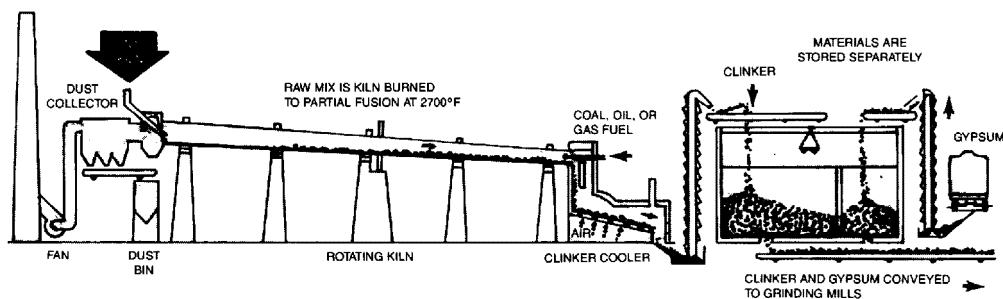
1. Stone is first reduced to 5-in. size, then to $\frac{3}{4}$ in., and stored.



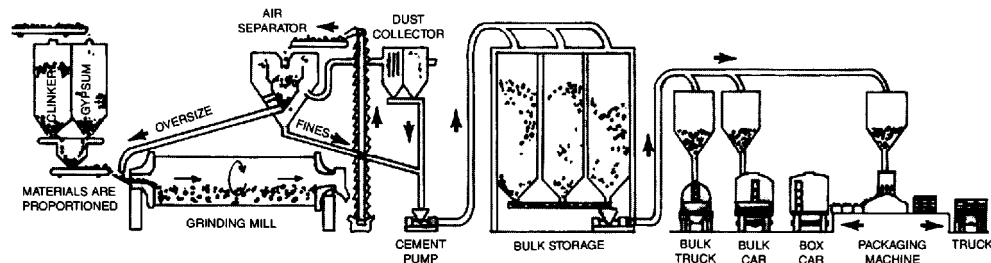
2. Raw materials are ground to powder and blended.



2. Raw materials are ground, mixed with water to form slurry, and blended.

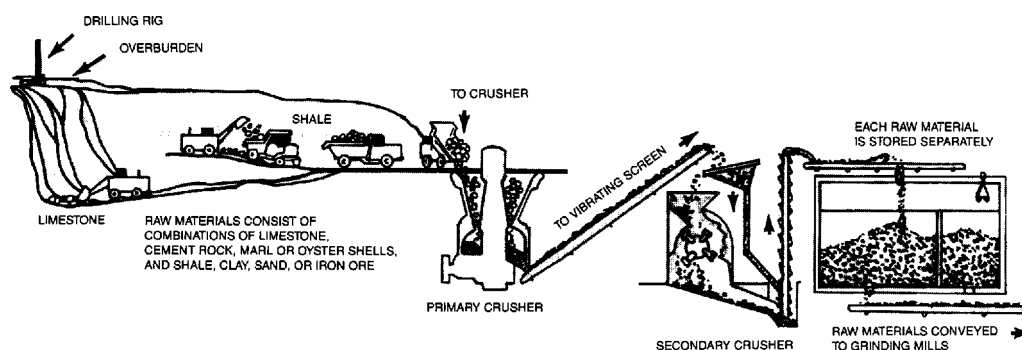


3. Burning changes raw mix chemically into cement clinker.

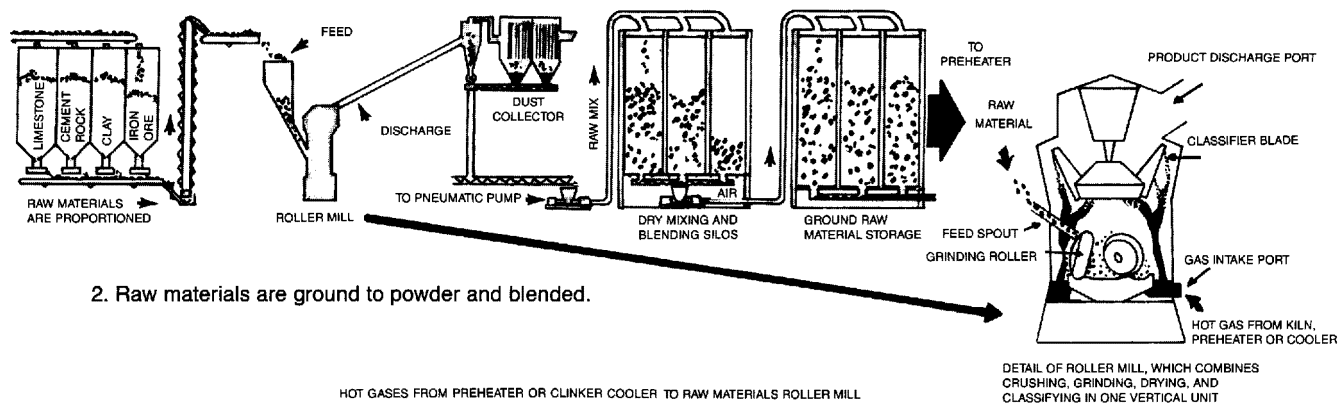


4. Clinker with gypsum is ground into Portland cement and shipped.

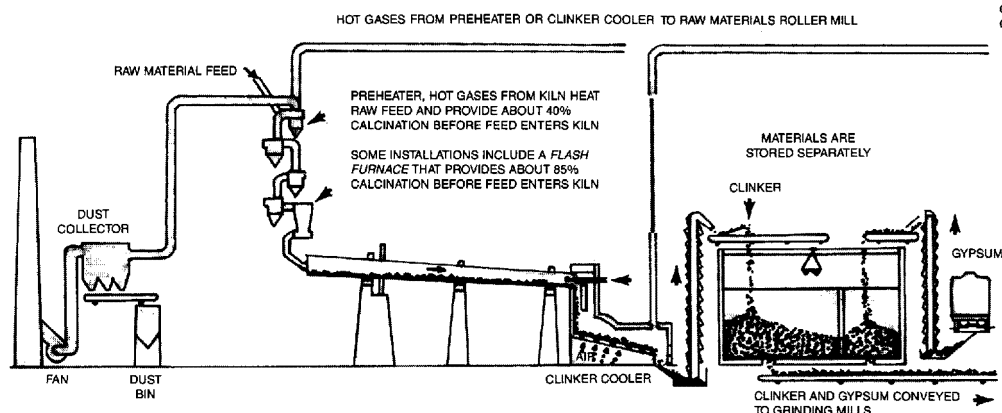
Fig. 1.1—Steps in the manufacture of Portland cement.



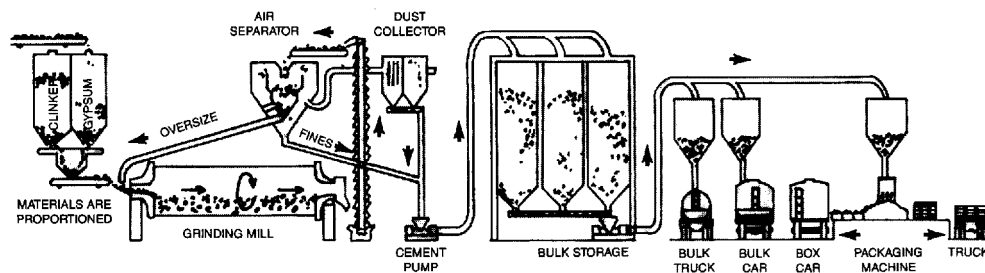
1. Stone is first reduced to 5-in. size, then to $\frac{3}{4}$ in., and stored.



2. Raw materials are ground to powder and blended.



3. Burning changes raw mix chemically into cement clinker. Note four-stage preheater, flash furnaces, and shorter kiln.



4. Clinker with gypsum is ground into Portland cement and shipped.

Fig. 1.2—New technology in dry-process cement manufacture.

TABLE 1.3—TYPICAL OXIDE ANALYSIS AND CALCULATED COMPOUND COMPOSITION OF PORTLAND CEMENTS (API CLASS G OR H BASIC CEMENT)

Oxide	Chemical Formula	%
Silicon dioxide	SiO_2	22.1
Aluminum oxide	Al_2O_3	4.2
Iron oxide	Fe_2O_3	4.3
Calcium oxide	CaO	64.8
Magnesium oxide	MgO	0.8
Sulfur trioxide	SO_3	2.7
Sodium oxide	Na_2O	0.2
Potassium oxide	K_2O	0.6
Sodium oxide equivalent*	Na_2O Equiv.	0.5
Loss on Ignition		0.4
Calculated Compound Composition	Chemical Formula and Abbreviation**	%
Tricalcium silicate	$3\text{CaO} \cdot \text{SiO}_2 = \text{C}_3\text{S}$	54
Dicalcium silicate	$2\text{CaO} \cdot \text{SiO}_2 = \text{C}_2\text{S}$	23
Tricalcium aluminate	$3\text{CaO} \cdot \text{Al}_2\text{O}_3 = \text{C}_3\text{A}$	4
Tetracalcium aluminoferrite	$4\text{CaO} \cdot \text{Al}_2\text{O}_3 \cdot \text{Fe}_2\text{O}_3 = \text{C}_4\text{AF}$	13
* Na_2O equivalent = $(0.658 \times \% \text{K}_2\text{O}) + \% \text{Na}_2\text{O}$		
**Dry Cement		

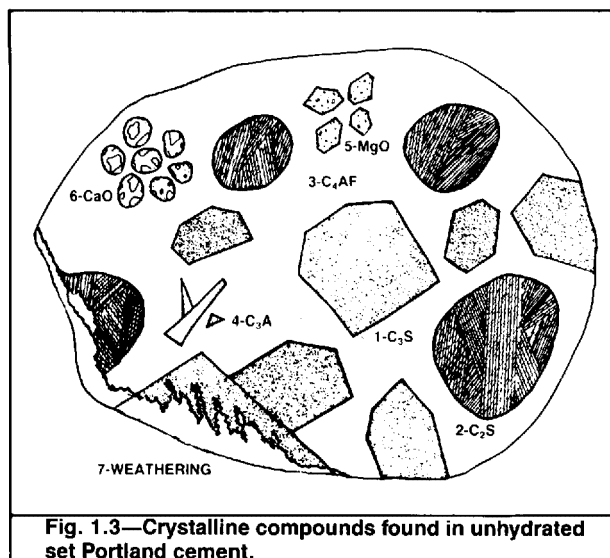
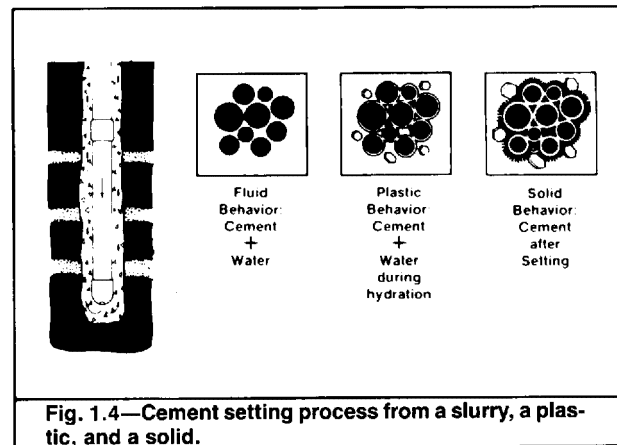
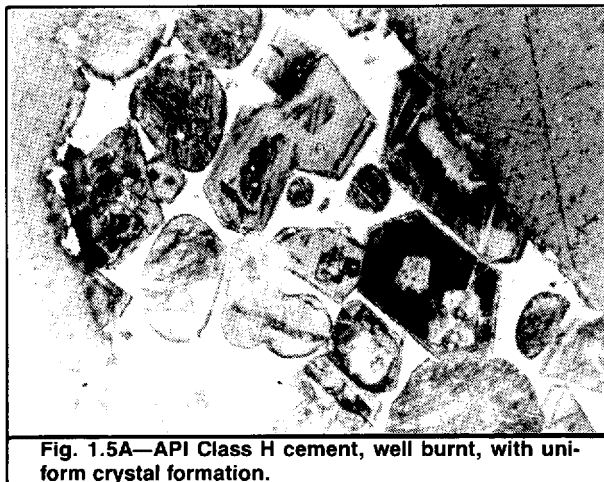
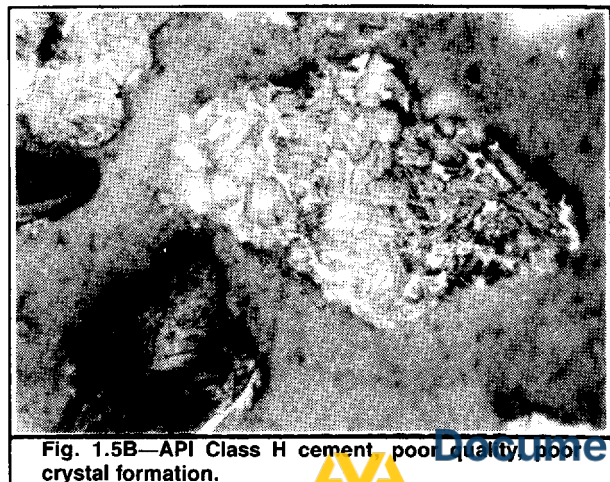
**Fig. 1.3—Crystalline compounds found in unhydrated set Portland cement.****Fig. 1.4—Cement setting process from a slurry, a plastic, and a solid.****Fig. 1.5A—API Class H cement, well burnt, with uniform crystal formation.****Fig. 1.5B—API Class H cement, poorly burnt, with poor crystal formation.**

TABLE 1.4—EFFECT OF TEMPERATURE AND PRESSURE ON CEMENT COMPONENTS

Well Condition Element	Effect on Cement Property
Increase temperature up to 200°F	• Increase rate of hydration • Decrease thickening time • Less severe sulfate attack • Increase fluid loss • Increase permeability
200°F to 400°F Range	• Lower values for strength internal surface area and nonevaporable water content • Decreases thickening time generally
Pressure	• Generally decreases thickening time
Pressures up to 1000 psi and 2000 psi	• Greater heat of hydration, surface area, and nonevaporable water content
Pressures above about 2000 psi	• Cause no appreciable further effect on heat of hydration, surface area, and nonevaporable water content

(cement-water mixtures) cured at atmospheric conditions and at elevated temperatures and pressures. A summary of reactions of cement minerals at atmospheric conditions and at elevated temperatures is cited in the literature.¹¹ The effects of temperature and pressure on cement properties are shown in Table 1.4.

1.5 API Standardization Background

API Code 32 and RP 10B Standards. Test procedures and specifications for the performance of various types of Portland cement in construction work are maintained by the ASTM. ASTM tests were determined by the oil industry to be inadequate for determining the performance of cements in wells because ASTM tests were made under conditions unlike those encountered in well cementing operations. The literature as reviewed by B. E. Morgan¹² reveals that this fact was recognized since the early use of Portland cements in wells.

In 1937 the American Petroleum Institute established the first committee to study cements. There already existed several cement-testing laboratories equipped with strength-measuring apparatus and stirring devices to determine the fluidity or pumpability of cement slurries at down-hole temperatures.

With the establishment of cement-testing laboratories, many new developments occurred in well cements between 1937 and 1950.¹³ During that period, a need arose for standardization of cement testing. To fulfill that need, the Mid-Continent API Committee on Oil-Well Cements prepared the proposed Code 32 in 1940. However, it was not until 1948 that the first edition of the Tentative API Code 32 was issued, entitled "API Code for Testing Cements Used in Wells." This code encompassed a specification governing test procedures, methods, and equipment used to evaluate and define those physical properties of special importance to the oil and gas industry. The objects of the code were to promote standardization and uniformity and to eliminate discrepancies and misunderstandings relative to cement slurry behavior in the laboratory as well as in actual cementing operations.

The tentative 1948 Code 32 included ASTM devices as well as stirring devices specifically designed for testing well cements as follows.

1. ASTM device.

A. Home appliance mixer (either hoop or fan type) for mixing cement slurries.

B. Setting-time devices (Vicat and Gillmore) wherein setting time of neat cement slurries could be determined at temperatures in the range of 80 to 200°F under atmospheric pressure.

C. Strength-measuring apparatus (compression and tensile strength) for measuring the strength of cement specimens in the range of 80 to 200°F under atmospheric pressure.

2. Well cement test devices for determination of cement thickening time.

A. Standard of California atmospheric pressure stirring device (80 to 200°F).

B. Halliburton atmospheric pressure stirring device (80 to 200°F).

C. Stanolind pressure-temperature thickening time tester.

The types of cement listed in the code were identified merely as (1) low fineness (slow-set or oilwell), (2) normal fineness (ASTM types I, II, IV, V), and (3) high fineness (ASTM type III).

A procedure for determining thickening time under down-hole simulated well conditions in the range of 1000 to 18,000 ft was also incorporated. Field data for wells 5000 to 14,000 deep, having average mud circulating pressures and bottomhole temperatures, are also included and are the basis for casing-cementing well simulation schedules.

API Code 32 was transferred to the jurisdiction of the national Committee on Standardization of Oil-Well Cements and redesignated RP 10B. This recommended practice remained tentative until 1954, and in 1956 RP 10B was advanced to "standard" by the national API Committee. Table 1.5 summarizes significant changes which evolved during 1940-1979 for API Code 32 and standard RP 10B.

API Std 10A Standard

In 1952 the national API Committee adopted standards for six classes of cements used in cementing operations for oil and gas wells. The first tentative standard in 1953 was designated API Std 10A and entitled "Specification for Oil-Well Cements." The standards for six API

**TABLE 1.5—SUMMARY - SIGNIFICANT CHANGES ADOPTED BY API FOR API CODE 32 AND RP 10B
RECOMMENDED PRACTICES (1940-1979)**

- 1937— API established committee to study oil-well cements.
- 1940— Proposed API Code 32 was prepared by F. E. Davis, Chairman of the Special Subcommittee on Oil Well Cements.
- 1948— The first edition of Tentative API Code 32 issued February 1948 entitled "API Code for Testing Cements Used in Wells (Tentative)." This code encompassed a specification governing test procedures, methods, and equipment used to evaluate and define those physical properties of special importance to the oil and gas industry.
- 1952— API Code 32 transferred to the jurisdiction of the Committee on Standardization of Oil-Well Cements and redesignated RP 10B. This recommended practice remained tentative from 1952 (Second Edition) to 1954 (Fourth Edition).
- 1956— RP 10B, Fifth Edition, May 1956.
- RP 10B advanced to "Standard" in June 1955 (Adopted June 1955, Circ PS-1054*). Tentative test for fluid loss also adopted and included in this edition.
- 1957— RP 10B, Sixth Edition, May 1957.
- Vicat Setting-Time Test deleted (Adopted June 1956, Circ PS-1083).
- 1958— RP 10B, Seventh Edition, January 1958.
- Following items were adopted at the June 1957 meeting (Circ PS-1109):
- Propeller-type two-speed, 1-qt mixing device (home-appliance type and heavy bench-type mixing devices deleted).
 - 750 ml slurry volume for test slurries.
 - Mixing procedure for 1-qt mixing device.
- 1959— RP 10B, Eighth Edition, January 1959.
- Following items were adopted at the June 1958 meeting (Circ PS-1161):
- Four-quart, propeller-type, multiple-speed mixing device.
 - Slurry volumes and mixing time requirements for the 4-qt mixing device.
 - Title changed to include cement additives, i.e., API Recommended Practice for Testing Oil-Well Cements and Cement Additives.
- 1960— RP 10B, Ninth Edition, January 1960, (Adopted June 1959, Circ PS-1161).
- Determination of water content of slurry using maximum and minimum water procedures adopted.
 - Also, rate of loading for testing compressive strength specimens specified (i.e., 4000 psi/min rate for normal-strength specimens and 1000 to 2000 psi/min rate for low-strength specimens, 500 psi or less).
- 1961— RP 10B, Tenth Edition, March 1961 (Adopted June 1960, Circ PS-1186).
- Fluid-loss test advanced to standard. Name changed from "filter" loss to "fluid" loss.
 - Tentative Permeability Test adopted.
- 1962— RP 10B, Eleventh Edition, March 1962 (Adopted June 1961, Circ PS-1208).
- Numbering of sections changed.
 - Class N cement deleted.
 - Atmospheric Pressure Thickening-Time Test-B (California Tester) deleted.
 - Normal water procedure adopted based on determination of slurry yielding a consistency of 11 ± 1 poises.
 - Atmospheric Pressure Thickening-Time Test use changed as procedure used in determination of Water Content and Fluid-Loss Tests.
 - Revised (Table 7.1 - Well-Simulation Test Schedules for Curing Strength Schedules).
 - Revised (Tables 9.1 and 9.2 - Basis for Casing-Cementing and Squeeze Cementing Well-Simulation Test Schedules, respectively based on a survey of field operations and reflecting conditions as severe as 75% of the jobs surveyed).
- 1963— RP 10B, Twelfth Edition, March 1963 (Adopted June 1962, Circ PS-1234).
- Related API publications included in Foreword.
 - Weight of test samples table revised and expanded to include all tests in RP 10B.
 - Water percentage for Classes D, E, and F retarded cements reduced from "40%" to "38%."
 - Free Water Content procedure adopted. New procedure based on revisions to Maximum Water Content procedure.
 - Fluid-Loss Test procedure revised to include high-pressure filter press apparatus.
 - Fann Thickening-Time Tester adopted as tentative pressure-temperature consistometer intended for field work only.
- 1964— RP 10B, Thirteenth Edition, March 1964 (Adopted June 1963, Circ PS-1260).
- Class G basic cement adopted as tentative (44% water).
 - Tentative Determination of Rheological Properties adopted.
 - Tentative Pressure-Temperature Consistometer Apparatus and test procedure for field work adopted and included as an appendix to RP 10B.
- 1965— RP 10B, Fourteenth Edition, March 1965 (Adopted June 1964, Circ PS-1285).
- Atmospheric Pressure Consistometer (Halliburton) moved to Appendix of RP 10B.
 - "Tentative" from Class G cement deleted.
- 1967— RP 10B, Fifteenth Edition, January 1967 (Adopted June 1965 and June 1966, Circ PS-1309 and Circ PS-1325, respectively).
- Class H basic cement adopted as tentative.
 - Slurry container rotation of 150 rpm adopted for Thickening-Time Tester (Pan American).
 - Slurry volume requirement for Classes A, B, C, D, E, F, G, and H changed from 750 ml to 600 ml when using the 1-qt mixing device.
- 1969— RP 10B, Sixteenth Edition, April 1969 (Adopted June 1968, Circ PS-1363).
- Calibration of potentiometer mechanism using weight-loaded type potentiometer calibrating device. Use of Paratone equilibrium oil adopted as alternate method.
- 1971— RP 10B, Seventeenth Edition, April 1971 (Adopted June 1971, Circ PS-1401).
- Class H cement advanced to "standard."
 - Tentative well-simulation test procedures for hesitation squeeze-cementing adopted.
- 1972— RP 10B, Eighteenth Edition, April 1972 (Adopted June 1971, Circ PS-1422).
- Tentative Fluid Density Balance adopted for measuring the absolute density of a field sample.
 - Rotational speed of slurry container increased from "35 rpm" to "150 rpm" (Atmospheric Pressure Consistometer).
- 1974— RP 10B, Nineteenth Edition, January 1974 (Adopted June 1972, Circ PS-1443 and June 1973, Circ PS-1468, respectively).
- Tentative Class J cement based solely on performance data adopted.
 - Height (238 mm min, 248 mm max) of graduated portion of 250 mL graduate cylinder specified. Graduate is used in determination of free water of Class G and H cements.
 - Thickening-time test schedules for determination of specification thickening time of different API class cements were reclassified as Casing Cement Specification Test schedules.
 - Tentative gradient casing-cement well-simulation test schedules adopted. Schedules designed to represent field practices (1000 ft to 20,000 ft).
 - Delete Pressure-Temperature Consistometer (Fann).
 - Tentative Arctic Cementing Testing Procedures adopted.
 - Tentative deleted from Pressurized Fluid Density Balance.
- 1977— RP 10B, Twentieth Edition, April 1977 (Adopted June 1977, Circ PS-1536).
- Metric conversions introduced.
 - Gradient Casing-Cementing Schedules redesignated 1g through 11g (1000 ft to 20,000 ft).
 - Tentative deleted from Arctic Cementing Testing procedure.
- 1979— RP 10B, Twenty-First Edition, December 1979 (Adopted June 1979, Circ PS-1614).
- Testing equipment and procedures divided into sets of mandatory (required by Spec 10A) and nonmandatory testing practices for field operating tests.
 - Alternate 1-qt size mixer adopted capable of controlling speed as required.
 - Mixing speed "slow" and "high" specifications adopted for 1-qt mixer.
 - Procedure approved for filling pressurized consistometer cup from the top and use of alternative flat diaphragm.

*Number designation of API Report for Annual Meetings of API Standardization Committee

classes of well cements were comprised of both chemical and physical requirements.

Chemical requirements were determined by using ASTM procedures, while the physical requirements were determined in accordance with procedures outlined in RP 10B and ASTM.

The chemical tests included determination for MgO, SO₃, loss on ignition, insoluble residue, and C₃A. The physical tests included determinations for soundness (ASTM test for autoclave expansion), fineness (ASTM C 115 test), compressive and tensile strength, and the thickening time test. The choice of thickening time tester (California, Halliburton, or Stanolind) was optional in the determination of thickening time for Classes A, B, and C cements. However, thickening time tests for Classes D, E, and F cements had to be determined in the Stanolind pressure-temperature tester.

Table 1.6 summarizes significant changes which were incorporated in API Std 10A by the national API Committee during the years 1953-1979.

Listed below are some of the most notable achievements of the API Committee during the above period.

1. Adoption of Class N retarded cement specifications in 1956 and subsequent deletion in 1962.
2. Adoption of specifications for Classes G and H basic cements in 1965 and 1971, respectively.
3. Adoption in 1977 of specifications for high-temperature Class J basic cement, approved solely on the basis of performance requirements.
4. Adoption in 1959 of bentonite and barite specifications, and in 1972, specifications for fly ash.

In 1972, the national API Committee approved a change in the document 10A designation to "Spec 10A" instead of "Std 10A" to agree with and to accurately reflect specifications content.

API Spec 10 Standard (Combined Spec 10A and RP 10B). Standardization studies which were published annually by API in two booklets, Volume 10A and Volume 10B, were combined into a single booklet. The first edition of the combined document, designated "API Spec 10," was issued in 1982.

The assigned title of the combined API Spec 10 single volume was changed to "API Specification for Materials and Testing for Well Cements."

Primary objectives for the consolidation were (1) to place in one section all the chemical and physical specifications, mandatory test procedures and mandatory test equipment for materials (cement and cement additives) required to determine conformance of the materials with chemical and physical requirements embodied in the specifications; and (2) to place in another section optional nonmandatory testing procedures which may be used in association with specified field applications. Table 1.7 summarizes the chronology of significant annual modifications to the API Spec 10 document (1982-1988).

Other API Committee 10 Documents. Standardization studies also resulted in the publication of the following documents under the jurisdiction of Committee 10. *Bul 10C, "Bulletin on Oil Well Cement Nomenclature,"* provides the definitions for the commonly used terms

associated with well cementing. The first edition of Bul 10C was issued in 1963. Modifications were incorporated in two subsequent editions which were issued in 1969 and 1984. In 1988 the Production Department of the American Petroleum Institute issued the first edition of "Glossary of Oilfield Production Terminology (GOT)." Abbreviations and definitions were compiled from all API Publications including all 385 terms listed in the 1984 edition of Bul 10C. The stated purpose of GOT is to provide a standard of previously used abbreviations and definitions. Bulletin 10C was removed from the jurisdiction of Committee 10 on Well Cements.

API Std 10D, "Specification for Casing Centralizers," covers the minimum performance requirements for standard and close tolerance spring-bow centralizers. It is not applicable to rigid or positive centralizers. Recommended testing equipment and procedures, as well as marking requirements and the application of the API monogram, are included. In addition, recommendations for determining centralizer spacing, based on centralizer performance and required stand-off, in deviated and dog-leg holes are presented. The first edition was issued in 1971. Modifications to the specifications were added in 1973 (second edition) and 1986 (third edition).

API RP 10E, "Recommended Practice for Application of Cement Lining to Steel Tubular Goods, Handling, Installation, and Joining," was developed through the joint effort of members of the National Association of Corrosion Engineers (NACE) T-1G-8 Task Group on Cement Lining of Tubular Goods, and the API Task Group on Cement Lining of Steel Pipe. This recommended practice was developed to provide standard procedures for the plant application of cement lining to oilfield tubular goods and recommended methods of joining cement-lined pipe. The first edition of RP 10E (tentative) was issued in 1978 and reissued in 1982. However, in 1984 concerns were raised by the API Legal Department concerning the use of asbestos in the cement mix. Upon approval in 1984 by the national cement Committee 10, the API Production Department withdrew API RP 10E and a task group was appointed to study the use of asbestos in cement-lined pipe. A solution was proposed and approved by the national Committee 10 from a recognized cement lining company to use an alternate additive for asbestos. Based on tests by this company the viable surrogate additive was an alkali-resistant glass fiber. Substitution of the alternate fiber for asbestos and other minor editorial modifications removed the concerns of the API Legal Department, and thus this action cleared the way for the publication and issuance of RP 10E (Second Edition) in 1987.

The proposed "API Recommended Practice for Performance Testing of Cementing Float Equipment" has been approved by the national committee. This recommended practice was released in print early 1989. Development of the RP, which commenced in 1986 required approximately two years. Its purpose is to provide recommended procedures for the performance testing of cementing float equipment.

TABLE 1.6—SUMMARY - SIGNIFICANT CHANGES INCORPORATED IN API STD 10A (1953-1979)

1953—Tentative standard was approved and issued in 1953 and entitled "API Specification for Oil-Well Cements," First Edition, March 1953. (Adopted June 1952 and December 1952, Circ PS-958 and Circ PS-972, respectively). • Specification provided standards for six API class cements (Classes A, B, C, D, E, and F) used in cementing operations for oil and gas wells. Classes A, B, and C cement were similar to ASTM construction-type cements; Classes D, E, and F were retarded cements possessing a chemical composition similar to ASTM Type II cement. 1955—Std 10A Advanced to "standard." Second Edition, 1955 (Adopted June 1953, Circ PS-993 and June 1954, Circ PS-1022, respectively). • List of authorized manufacturers approved (total six domestic manufacturers). • Use of API Monogram requirements by cement manufacturers incorporated. 1956—Tentative Class N retarded cement requirement approved Std 10A, Third Edition, May 1956 (Adopted June 1955, Circ PS-1054). 1957—Eight-hour compressive strength specifications approved for Classes A, B, C, and N cements. Std 10A, Fourth Edition, May 1957 (Adopted June 1956, Circ PS-1083 and 1083A). 1958—Eight hour compressive strength specifications approved for Classes N, D, E, and F. • Twenty-four hour compressive strength specifications approved for Classes D, E, and F. • Specifications for 24 hour compressive strength revised for Classes A and B cements. • Thickening-time specification (Schedule 1, 80°F BHCT) approved for Classes A, B, and C cements. • Twenty-four hour tensile strengths for all classes of cements deleted. Std 10A, Fifth Edition, January 1958 (Adopted June 1957, Circ PS-1109). 1959—Std. 10A, Sixth Edition, January 1959 (Adopted June 1958, Circ PS-1137). • Specifications for untreated bentonite and barite (barium sulfate rock) approved. • Class N cement 8-hour and 24-hour compressive strength specifications revised downward when cured at 140°F under atmospheric pressure. • Pressure-temperature thickening-time specifications for Classes A, B, C, N, D, E, and F cements revised upward (lengthened). • Atmospheric pressure thickening-time (Halliburton) specifications for Classes A, B, C, N, and D revised upward (lengthened). • Atmospheric pressure thickening-time (California) specifications for Classes N and D revised upward (lengthened). • Document of title changed to reflect inclusion of specifications for cement additives. 1960—Std 10A, Seventh Edition, January 1960 (Adopted June 1959, Circ PS-1161). • Atmospheric pressure consistometer A (Halliburton) and B (California) relegated to alternate tester status. In case of dispute, pressure-temperature thickening test shall govern. • Class N thickening-time specification under Schedule 5A revised downward (shortened). • Thickening-time specifications for Classes N and D using atmospheric pressure consistometers A and B deleted. 1962—Std 10A outlined in Eighth Edition of Std 10A, March 1962 (Adopted June 1960 and 1961, Circ PS-1186 and PS-1208, respectively). • Thickening-time physical requirements specified for atmospheric pressure consistometers deleted. • Chemical and physical test requirements for Class N cement deleted. • Eight-hour and 24-hour compressive strength specifications revised for Classes D and E cements. • Thickening-time specifications for Classes A, B, and C cements shortened from 110 to 90 minutes under Schedules 1 (1000 ft) and 4 (6000 ft). • Thickening-time specifications for D, E, and F revised. • Mandatory tests and equipment required for conducting of physical tests for API manufactured cement. 1963—Std 10A, Ninth Edition, March 1963 (Adopted June 1962, Circ PS-1234). • Thickening-time specifications for Classes D, E, and F shortened when tested under Schedule 6 (10,000 ft), and lengthened for Class F under Schedule 9 (16,000 ft).	• Table incorporated showing authorized manufacturers' cement trade names vs API Cement Class Designations. 1964—Std 10A, Tenth Edition, March 1964 (Adopted June 1963, Circ PS-1260). • Specifications for tentative Class G basic cement approved. • API Classes A and B cements redesignated "ordinary (O)" instead of "regular" type. • Chemical specifications approved for cements (Classes B, C, D, E, F, and G) designated "moderate" sulfate-resistant (MSR) and "high" sulfate resistant (HSR) types. • Specification approved for total alkali content expressed as sodium oxide equivalent for tentative Class G cement (both MSR and HSR types). • Physical test specification requirements approved for Class G cement. • Requirements included for soundness, compressive strength (under elevated pressure), and thickening-time for MSR and HSR types. • SO₃ oxide specification raised for Class C "O" type from "3.00%" to "4.00%." 1965—Std 10A, Eleventh Edition, March 1965 (Adopted June 1964, Circ PS-1285). • Class G cement elevated to "standard" for both MSR and HSR types. • Free water specification approved for Classes G MSR and HSR types. 1966—Std 10A, Twelfth Edition, March 1966 (Adopted June 1965, Circ PS-1309). • Additional specifications for bentonite approved (Fann reading, yield point, and filtration properties). • No. 325 sieve residue specification approved for barite. 1967—Std 10A, Thirteenth Edition, January 1967 (Adopted June 1966, Circ PS-1327). • Tentative chemical and physical requirement specifications approved for Class H cement (MSR type only). • Maximum C₃S specification raised to "65%" from "58%" for Class G HSR cement only. 1969—Std 10A, Fourteenth Edition, April 1969 (Adopted June 1968, Circ PS-1363). • Metric conversions of U.S. customary units commenced in this edition. • Tentative specifications for fly ash approved. 1970—Std 10A, Fifteenth Edition, May 1970 (Adopted June 1969, Circ PS-1381). • Sampling approved as mandatory test. 1971—Std 10A, Sixteenth Edition, 1971 (Adopted June 1970, Circ PS-1401). • Specification SO₃ values approved to correspond with changes made by ASTM, i.e., cements for which values increased are Class A (O), Class B (MSR and HSR), and Class C (O, MSR, and HSR). 1972—Spec 10A, Seventeenth Edition, 1972 (Adopted June 1971, Circ PS-1422). • Approved change to designate document API "Spec" 10A instead of API "Std" 10A. • Fly ash advanced to "standard." 1974—Spec 10A, Eighteenth Edition, January 1974 (Adopted June 1972 and June 1973, Circ PS-1443 and PS-1468, respectively). • Tentative Class J basic cement approved based solely on physical performance requirements. • Mandatory Test Equipment for additive suppliers approved. 1977—Spec 10A, Nineteenth Edition, April 1977 (Adopted June 1966, Circ PS-1536). • Class J cement advanced to "standard." • Tentative chemical specifications for Class H - HSR cement approved. 1979—Spec 10A, Twentieth Edition, April 1979 (adopted June 1977 and 1978, Circ PS-1562 and PS-1588, respectively). • Magnesium oxide (MgO) content increased from "5.0% max" to "6.0% max" for all API cement classes to correspond with increases approved by ASTM for similar types of ASTM cements. • Tentative 8-hour compressive strength specs approved for Classes G-MSR, G-HSR, H-MSR, and H-HSR cements when tested at 100°F and 140°F under atmospheric pressure, i.e., 300 psi/min, 100°F atmospheric pressure, 1500 psi/min, 140°F atmospheric pressure.
---	--

TABLE 1.7 —SUMMARY - CHRONOLOGY OF THE MODIFICATIONS TO API SPEC 10, "MATERIALS AND TESTING FOR WELL CEMENTS" (1982-1988)

1982— Spec 10, First Edition, January 1982 (adopted June 1981, Circ PS-1664). • Spec 10A Standards and RP 10B Recommended Practices are combined into one document. Specifications are covered in Sections 1 through 14; operating test procedures are covered in Appendices A through O. • Compressive strength requirements (8 hours @ 100°F and 140°F, atmospheric pressure) advanced to "standard." • Name of document designated "API Specification for Materials and Testing for Well Cements." • Test Manual of Cement Testing approved for insertion into "Operating Test" section. 1984— Spec 10, Second Edition, June 15, 1984 (adopted June 1983, Circ PS-1712). • Specifications for Class H - HSR advanced to "standard." • Revised Section 14, "Packaging, Handling, and Storage," approved as tentative. 1986— Spec 10, Third Edition, July 1986 (adopted June 1984 and June 1985, Circ PS-1739, and Circ PS-1767, respectively). • Specification on barite deleted. • Specification for weight loss requirement of 1-qt mixer propeller blade approved. • Rate of loading for compressive strength specimens revised and approved. • Specifications revised and approved for oil used as heating and pressure medium in pressurized consistometer. • Relationship of Bearden units of consistency between the pressurized consistometer (Bc) and the atmospheric pressure consistometer (ABc) was approved.	• Fluid-loss test (revised) tentative designation deleted. • Revised procedure approved for "Determination of Rheological Properties Using a Rotational Viscometer." • New tentative calculational procedure approved entitled "Procedure for Calculating Pressure Drop, Rate for Plug Flow and Rate for Turbulent Flow for Cement Slurries in Pipes and Annuli." • New tentative precision statement approved entitled "Statement for API Testing." • New tentative calibration procedure approved entitled "Calibration Procedures for Thermocouples and Temperature Indicators." • New tentative operating test procedure approved entitled "Investigation of Preflushes and Spacers for Cementing." 1988— Spec 10, Fourth Edition, August 1, 1988 (Adopted June 1987 Circ PS-1827). • Revised section on "Sampling" specification requirement approved. • Change in temperature requirement of water and cement for mixing cement slurries ($73 \pm 2^\circ\text{F}$) approved. • Change in temperature requirement to which graduate is exposed during quiescent 2-hour period of free water test ($73 \pm 2^\circ\text{F}$) was approved. • Specifications for fly ash deleted. Information guidelines on fly ash inserted in operating test section. • Revisions approved in procedure for determining rheological properties. • Revised statement of precision approved for API Testing.
--	---

1.6 Publication of Standardization Studies

Throughout the existence of the API Committee on Standardization of Well Cements, the committee has sought to inform both users and manufacturers about the important contributions which have resulted from standardization studies. Many of the significant papers on early standardization efforts were either direct or indirect studies sponsored by the API Mid-Continent District Study Committee on Cementing Practices and Testing of Oil-Well Cements. Table 1.8 summarizes these significant paper contributions by API Committee 10 and Mid-Continent District Committee (MC).⁵

1.7 Current API Well Cement Classifications

The petroleum industry purchases cements manufactured predominately in accordance with API classifications as published in API Specifications for Materials and Testing for Well Cements.¹⁴ These standards have been published by the American Petroleum Institute in Dallas, Texas since 1953, when the first national standards on cements for use in wells were issued. These specifications are reviewed annually and revised according to the needs of the oil industry (Table 1.7). The different classes of API cements for use at down-hole temperatures and pressures are defined below. They are listed in API Spec 10 dated August 1988.¹⁴

Class A. Intended for use from surface to 6000 ft depth, when special properties are not required. Available only in ordinary type (similar to ASTM C 150, Type I).*

Class B. Intended for use from surface to 6000 ft depth, when conditions require moderate to high sulfate resist-

ance. Available in both moderate (similar to ASTM C 150, Type II) and high sulfate-resistance types.

Class C. Intended for use from surface to 6000 ft depth, when conditions require high early strength. Available in ordinary and moderate (similar to ASTM C 150, Type III) and high sulfate-resistance types.

Class D. Intended for use from 6000 ft to 10,000 ft depth, under conditions of moderately high temperatures and pressures. Available in both moderate and high sulfate-resistance types.

Class E. Intended for use from 10,000 ft to 14,000 ft depth, under conditions of high temperatures and pressures. Available in both moderate and high sulfate-resistant types.

Class F. Intended for use from 10,000 ft to 16,000 ft depth, under conditions of extremely high temperature and pressures. Available in both moderate and high sulfate-resistant types.

Class G. Intended for use as a basic well cement from surface to 8000 ft depth as manufactured, or can be used with accelerators and retarders to cover a wide range of well depths and temperatures. No additions other than calcium sulfate or water, or both, shall be interground or blended with the clinker during manufacture of Class G well cement. Available in moderate and high sulfate-resistant types.

Class H. Intended for use as a basic well cement from surface to 8000 ft depth as manufactured, or can be used with accelerators and retarders to cover a wide range of well depths and temperatures. No additions other than

calcium sulfate or water, or both, shall be interground or blended with the clinker during manufacture of Class H well cement. Available in moderate and high sulfate-resistant types.

Class J. Intended for use as manufactured from 12,000 ft to 16,000 ft depth under conditions of extremely high temperatures and pressures or can be used with accelerators and retarders to cover a range of well depths and temperatures. No additions of retarder other than calcium sulfate, or water, or both, shall be interground or blended with the clinker during manufacture of Class J well cement.

*Depth limits are based on the conditions imposed by the casing-cement specification tests (Schedules 1, 4, 5, 6, 8, 9), and should be considered as approximate values.

ASTM C 150: Standard Specification for Portland cement is available from American Society for Testing and Materials, 1916 Race Street, Philadelphia, PA 19103.

1.8 Cement Properties Covered by API Specifications

In well completion operations, cements are almost universally used to displace the drilling mud to fill space between the casing and the openhole. To serve this purpose, cements must be designed for wellbore environ-

ments varying from those at the surface to those at depths exceeding 30,000 ft, where temperatures range from below freezing in permafrost areas to more than 700°F in wells drilled for geothermal steam production.

Specifications do not cover all the properties of cements over such broad ranges of depth and pressure. Specifications do, however, embody a realistic method of classifying Portland cement for use in wells, by specifying the required properties. It furnishes the manufacturer a list of properties needed in the product, and it assures the purchaser that the product meets certain minimum requirements. In addition, it greatly simplifies communication among the manufacturer, the distributor, and the consumer.

Although these properties describe cements for specification purposes, well cements should have other properties and characteristics to provide for their necessary functions down-hole.¹⁰

The chemical and physical requirements of API Classes of cements as defined in API Spec 10 are shown in Tables 1.9 and 1.10.

API specifications are not enforced by an official agency; however, use of the API monogram indicates that the manufacturer has agreed to make cement according to the specifications outlined in API Spec 10. Although the API defines nine different classes of cement, only A, B, C, G, and H are available from manufacturers and dis-

TABLE 1.8—SUMMARY - SIGNIFICANT PAPERS ON STANDARDIZATION EFFORTS DEVELOPED BY API COMMITTEE 10 AND THE OLD API MID-CONTINENT DISTRICT COMMITTEE

1941—API Prod. Bull. 228, API Proc. Spec. IV, "Report of Special Subcommittee on Oil-Well Cements" API Proc. Sec. IV (Prod. Bull. 228) (1941) 84-85.	1955—"A Study of Surface Casing and Open-Hole Plugback (MC) Cementing Practices in the Mid-Continent District," Mid-Continent District Study Committee on Cementing Practices, Spring Meeting of the Mid-Continent District, Division of Production, March 23-24-25, 1955. Drill. and Prod. Prac., API, 1955.
1951—Ludwig, N.C.: "Effects of Sodium Chloride on Setting (MC*) Properties of Oil-Well Cements," Spring Meeting of the Mid-Continent District, API Division of Production, Amarillo, TX (March 21-23, 1951).	1958—Morgan, B.E.: "API Specification for Oil Well Cements," (MC) Drill. and Prod. Prac., API (1958) 83.
1951—Roberts, J.B.: API Code 32, "Testing Oil-Well Cements - (MC) Applications, Limitations, and Versatility," Spring Meeting of the Mid-Continent District, API Division of Production, Amarillo, TX (March 21-23, 1951).	1959—"A Survey of Field Casing Cementing Operations," Committee on Standardization of Oil-Well Cements, Subcommittee on RP 10B, Well Simulation Tests Task Group (March 16, 1959).
1951—"The Effects of Drilling-Mud Additives on Oil-Well Cements," API Mid-Continent District Study Committee on Cementing Practices and Testing of Oil-Well Cements (Sept. 1951).	1959—"A Survey of Field Squeeze Cementing Operations," (10) Committee on Standardization of Oil-Well Cements, Subcommittee on RP 10B, Well Simulation Tests Task Group (May 25, 1959).
1952—Saunders, C.D. and Nussbaumer, F.W.: "Trend in Use of (MC) Low-Weight Cement Slurries," API Mid-Continent District Study Committee on Cementing Practices and Testing of Oil-Well Cements, Wichita, KS (March 1952).	1965—"A Basic Oil Well Cement," API Standardization Committee 10, All 1965 District Spring Meetings, Division of Production (Feb. 1965).
1953—Dawson, C.W.: "Accomplishments and Objectives of API (10**) Standardization Committee on Oil-Well Cements," Symposium on Oil-Well Cements, Midyear Meeting of the Division of Production, API (June 16, 1953).	1972—Shell, F.J. and Tragesser, Art: "Accurate Bottom-Hole (10) Temperatures Are Needed," Second Annual Meeting, Division of Production, API (March 6-8, 1972).
1953—Anderson, Francis M.: "Modern Oil-Well Cementing Operations," Symposium on Oil-Well Cements, Midyear Meeting of the Division of Production, API, June 16, 1953.	1977—"Cement Blends Can Be Tested for Arctic Environments," Pet. Engr. Intl. (Feb. 1977) 22-30.
1954—Swayze, M.A.: "Effects of High Temperatures and Pressures on Strengths of Oil Well Cements," Drill. and Prod. Prac., API (1954) 72; Oil and Gas J. (Aug. 2, 1954) 103-105.	1977—"New Cement Test Schedules Issued," Oil and Gas J. (10) (July 25, 1977).
1955—"Report on Cooperative Tests on Sulfate Resistance of (MC) Cements and Additives," API Mid-Continent Dist. Study Committee on Cementing Practices and Testing of Oil-Well Cements (1955).	1980—Smith, D.K.: "Silica Flour-Mechanism for Improving Cementing Composition for High Temperature Well Conditions," Pet. Eng. Intl. (Dec. 1980) 43-48.
	1985—API Geothermal Paper, Oil and Gas J. (Feb. 11, 1985).
	(10)
	1986—Beirute, R.M.: "API Revised Procedures," Oil and Gas J. (10) (Sept. 22, 1986).

*MC - Abbreviation for API Mid-Continent District Committee

**10 - API Committee 10

TABLE 1.9—CHEMICAL REQUIREMENTS* FOR API CEMENTS

	Percent Required by Cement Class					
	A	B	C	D,E,F	G	H
Ordinary (O)						
Magnesium oxide (MgO), maximum	6.0	----	6.0	----	----	----
Sulfur trioxide (SO ₃), maximum ¹	3.5	----	4.5	----	----	----
Loss on ignition, maximum	3.0	----	3.0	----	----	----
Insoluble residue, maximum	0.75	----	0.75	----	----	----
Tricalcium aluminate (C ₃ A), maximum ²	----	----	15	----	----	----
Moderate Sulfate-Resistant (MSR)						
Magnesium oxide (MgO), maximum	----	6.0	6.0	6.0	6.0	6.0
Sulfur trioxide (SO ₃), maximum	----	3.0	3.5	3.0	3.0	3.0
Loss on ignition, maximum	----	3.0	3.0	3.0	3.0	3.0
Insoluble residue, maximum	----	0.75	0.75	0.75	0.75	0.75
Tricalcium silicate (3CaO•SiO ₂), maximum ²	----	----	----	----	58	58
Tricalcium silicate (3CaO•SiO ₂), minimum ²	----	----	----	----	48	48
Tricalcium aluminate (3CaO•Al ₂ O ₃), maximum ²	----	----	----	----	----	----
Total alkali content expressed as sodium oxide (Na ₂ O) equivalent, maximum ³	----	----	----	----	0.75	0.75
High Sulfate-Resistant (HSR)						
Magnesium oxide (MgO), maximum	----	6.0	6.0	6.0	6.0	6.0
Sulfur trioxide (SO ₃), maximum	----	3.0	3.5	3.0	3.0	3.0
Loss on ignition, maximum	----	3.0	3.0	3.0	3.0	3.0
Insoluble residue, maximum	----	0.75	0.75	0.75	0.75	0.75
Tricalcium silicate (3CaO•SiO ₂), maximum ²	----	----	----	----	65	65
Tricalcium silicate (3CaO•SiO ₂), minimum ²	----	----	----	----	48	48
Tricalcium aluminate (3CaO•Al ₂ O ₃), maximum ²	----	3	3	3	3	3
Tetracalcium aluminoferrite (4CaO•Al ₂ O ₃ •Fe ₂ O ₃) plus twice the tricalcium aluminate (3CaO•Al ₂ O ₃), maximum ²	----	24	24	24	24	24
Total alkali content expressed as sodium oxide (Na ₂ O) equivalent, maximum	----	----	----	----	0.75	0.75

* Methods covering the chemical analyses of hydraulic cements are described in ASTM C114: *Standard Methods for Chemical Analysis of Hydraulic Cement*.

¹ When the tricalcium aluminate content (expressed as C₃A) of the Class A cement is 8% or less, the maximum CO₃ content shall be 3%.

² The expression of chemical limitations by means of calculated assumed compounds does not necessarily mean that the oxides are actually or entirely present as such compounds. When the ratio of the percentages of Al₂O₃ to Fe₂O₃ ratio is greater than 0.64, the compounds shall be calculated as follows:

$$C_3A = (2.65 \times \% Al_2O_3) - (1.69 \times \% Fe_2O_3)$$

$$C_4AF = 3.04 \times \% Fe_2O_3$$

$$C_3S = (4.07 \times \% CaO) - (7.60 \times \% SiO_2) - (6.72 \times \% Al_2O_3) - (1.43 \times \% Fe_2O_3) - (2.85 \times \% SO_3)$$

When the ratio of Al₂O₃ to Fe₂O₃ is less than 0.64, an iron-alumina-calcium solid solution [expressed as (C₄AF + C₂F)] is formed and the compounds shall be calculated as follows:

$$ss(C_4AF + C_2F) = (2.10 \times \% Al_2O_3) + (1.70 \times \% Fe_2O_3) \text{ and } C_3S = (4.07 \times \% CaO) - (7.60 \times \% SiO_2) - (4.48 \times \% Al_2O_3) - (2.86 \times \% Fe_2O_3) - (2.85 \times \% SO_3)$$

³ The sodium oxide equivalent (expressed as Na₂O equivalent) shall be calculated by the formula:

$$Na_2O \text{ Equivalent} = (0.658 \times \% K_2O) + \% Na_2O$$

TABLE 1.10—PHYSICAL REQUIREMENTS FOR API CEMENTS

Well Cement Class				A	B	C	D	E	F	G	H	J ¹
Water by weight of well cement, %				46	46	56	38	38	38	44	38	J ¹
Soundness (autoclave expansion), maximum %				0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	---
Fineness ² (specific surface), minimum, m ² /kg				150	160	220	---	---	---	---	---	---
Free water content, maximum, ml				---	---	---	---	---	---	3.5 ³	3.5 ³	---
	Schedule Number,	Curing Temp (°F)	Curing Pressure (psi)	Minimum Compressive Strength, psi								
Compressive Strength Test,	---	100	Atmos.	250	200	300	---	---	---	300	300	---
	---	140	Atmos.	---	---	---	---	---	---	1500	1500	---
	8S	230	3000	---	---	---	500	---	---	---	---	---
	8S	290	3000	---	---	---	---	500	---	---	---	---
	9S	320	3000	---	---	---	---	---	500	---	---	---
Compressive Strength Test,	---	---	---	---	---	---	---	---	---	---	---	---
12-Hour Curing Time	8S	290	3000	---	---	---	---	---	---	---	---	500
	Schedule Number,	Curing Temp (°F)	Curing Pressure (psi)	Minimum Compressive Strength, psi								
Compressive Strength Test,	---	100	Atmos.	1800	1500	2000	---	---	---	---	---	---
	4S	170	3000	---	---	---	1000	1000	---	---	---	---
	6S	230	3000	---	---	---	2000	---	1000	---	---	---
	8S	290	3000	---	---	---	---	2000	---	---	---	---
	9S	320	3000	---	---	---	---	---	1000	---	---	---
	10S	350	3000	---	---	---	---	---	---	---	---	1000 ⁴
	Speci- cation Test Schedule	Curing Temp (°F)	Curing Pressure (psi)	Minimum Thickening Time, minutes ⁶								
Pressure	1	---	30	90	90	90	---	---	---	---	---	---
Temperature	4	---	30	90	90	90	90	---	---	---	---	---
Thickening	5	---	30	---	---	---	---	---	---	90	90	---
Time Test	5	30	---	---	---	---	---	---	---	---	---	---

¹ Water as recommended by the manufacturer.

² Determined by Wagner turbidimeter apparatus described in ASTM C 115: *Fineness of Portland Cement by the Turbidimeter*.

³ Based on 250 mL volume, percentage equivalent of 3.5 mL is 1.4%.

⁴ Compressive strength after 7 days shall be no less than the 24-hour compressive strength on Schedule 10S.

⁵ Bearden units of slurry consistency (Bc).

⁶ Thickening time requirements are based on 75 percentile values of the total cementing time observed in the casing survey, plus a 25% safety factor.

⁷ Maximum thickening time requirement for Schedule 5 is 120 minutes.

tributed in the USA. The number of API classes has been reduced to the point that API Classes G and H are those most widely used.⁹ Approximately 80% of the cement used in wells in non-Communist countries is manufactured in the U.S. and falls within these two classes. Approximately 65% of the well cement made in the U.S. is API Class H (mostly in the Gulf Coast and mid-continent operations), and 15% is API Class G, which is marketed in the California and Rocky Mountain areas. The remaining well cement used is either Class A (10%) or Class C (10%).

In international operations,⁹ most of the well cement used is API Class G (Canada, Europe, Middle East, South America, and Far East). Specialty cements⁹ constitute less than 1% of the worldwide down-hole market.

1.9 Current and Future Development of API Standards for Well Cements

The development of API standards for well cements has

been the result of the cooperative effort during the past several decades of personnel from producing companies, service companies, and cement manufacturers. These standards have evolved and have been planned by people who are well qualified, by experience in both laboratory testing and field operations, to prepare a practical, workable set of requirements for well cements.

The same dedication of purpose is still in evidence today in the refinement of API test methods and equipment and the development of new API standards and apparatus.

Much of the industry's current capability to design a well cement slurry is the direct result of the standardization of laboratory equipment and testing procedures and the availability of laboratory facilities for testing at simulated down-hole cementing conditions.

Current and future standardization studies under investigation include (1) revision of cementing temperature schedules based on well cementing field data.

opment of a recommended practice for the calibration of cement bond-logging tools using a test facility at Texas A&M University, (3) preparation of a trade journal article for standardization of pressure-temperature curing equipment, (4) revision of current standard static fluid-loss test procedure, (5) development of new test procedure for a stirring device that allows measurement of the filtration rates of a cement slurry under down-hole conditions after a simulated placement time, and (6) revision of the Spec 10 document to meet the challenges posed by the new upgraded API Q1 quality specification program.

The API Committee on Standardization of Well Cements also has under its jurisdiction a task group which conducts a voluntary, cooperative test program on an annual basis using a manufacturer's API Class G or Class H basic cement. The program is open worldwide to interested oil industry and cement manufacturers possessing equipment required to conduct thickening time, compressive strength, and free water tests in accordance with the procedures specified in API Spec 10. Emphasis of the program is placed on controls, test procedures and recommended tightening of controls in Spec 10 which are beneficial to the oil and gas industry, cement manufacturers, and governmental regulatory bodies.

1.10 Summary

The early history, manufacture, and chemistry of Portland cement is reviewed. A historical review of the development of API well cement standardization documents is also presented. Significant contributions and papers on standardization efforts made over the past several decades by API Committee 10 on Standardization of Well Ce-

ments and the old API Mid-Continent District Committee are presented and summarized for future reference.

References

1. Bogue, R.H.: *The Chemistry of Portland Cement*, Reinhold Publishing Company (1947).
2. Hadley, E.J.: *The Magic Powder*, G. P. Putnam's Sons, New York (1945).
3. Lesley, R.W.: *History of the Portland Cement Industry in the United States*, International Trade Press Inc. (1924).
4. Gonnerman, H.F.: "Development of Cement Performance Tests and Requirements," *Bulletin 93*, Research Department, Portland Cement Association, Skokie, IL (1958).
5. Swayze, M.A.: "Cooperative Study on Strength of Set Cement Cured at High Temperatures," API Drilling and Prod. Prac. Report for Mid-Continent Dist. Study Committee on Cementing Practices and Testing of Oil-Well Cements (1954), 72.
6. Kosmatka, S.H. and Panarese, W.C.: *Design and Control of Concrete Mixtures*, Portland Cement Association, Skokie, IL (1988).
7. Caveny, W.J. and Weigand, W.: "Microscopic Method Helps Assess Cement Performance," *Oil and Gas J.* (Sept. 26, 1983).
8. Caveny, W.J. and Weigand, W.: "Practical Oilwell Cement Microscopy," 1985 Int'l. Conference on Cement Microscopy, Fort Worth, TX (March 25-28, 1985).
9. Smith, D.K.: *Cementing*, Monograph Vol. 4 SPE Henry L. Doherty Series, NY and Richardson, TX (1987).
10. Hansen, W.C.: "Oil Well Cements," *Proc. Third International Symposium on the Chemistry of Cement* (London) (1952).
11. "Oil-Well Cementing Practices in the United States," API, New York (1959), Chapters 2 and 4.
12. Morgan, B.E.: "API Specification for Oil-Well Cement," *API Drilling and Prod. Prac.* (1958) 83-90.
13. Robinson, W.W.: "Cement for Oil Wells: Status of Testing Methods and Summary of Properties," *Drill. and Prod. Prac.*, API (1939) 567-91.
14. *API Spec 10, "Specification for Materials and Testing for Well Cements*, Fourth Edition, API, Dallas (August 1988).

Chapter 2

Cement Job Planning

author
Robert C. Smith

INDEX

SUBJECT	PAGE
2.1 Introduction	19
2.2 Cement Job Planning and Design	19
2.3 Cement Slurry Density	20
Casing Setting Depths	21
Selecting Slurry Density	22
2.4 Thickening Time Testing	23
Down-hole Pressure	23
Cementing Temperature	23
2.5 Compressive Strength Testing	27
2.6 Permeability	29
2.7 Fluid-Loss Testing	29
2.8 Free Water Testing	30
2.9 Rheology Determination	30
2.10 Bulk Blending	30
2.11 Job Execution	31
2.12 Job Monitoring	31
2.13 Quality Control	32

Chapter 2

Cement Job Planning

By: Robert C. Smith

Robert C. Smith is a well cementing consultant in Inola, OK. He retired from Amoco Production Co. in 1989 after 32 years service. He joined Amoco in 1957 as a petroleum engineer, with a BS degree in engineering from the University of Wyoming. For the past 21 years, he has been engaged in basic research on well completion and repair, primarily in the field of cementing. The previous 11 years he specialized in drilling, production, and secondary recovery operations in Wyoming and west Texas. He is a registered professional engineer (Oklahoma), the author of numerous publications and patents, and past chairman of the 1988 SPE Forum series meeting on primary cementing.

2.1 Introduction

The producing performance of a well depends in great part on a good primary cementing job. In a high-quality cement job, mud and gas channels have been permanently prevented, and there is a complete hydraulic seal between the casing and the formation throughout the zones of interest. A successful primary cementing operation requires careful coordination and control of many factors, beginning with job planning. This chapter discusses the important aspects of job planning and how they contribute to successful cementing.

2.2 Cement Job Planning and Design

The Team Effort. To assure proper job planning and slurry design, a team effort is essential. The team consists of employees of the service company, the operating company, and the drilling contractor. Communication and cooperation must be established early among all parties, particularly between drilling engineers and service company engineers.

Engineering the design of the cementing job to fit well requirements takes time. All personnel must apply the total, engineered concept, which starts with planning and design, continues through blending and mixing cement, and culminates in pumping cement. A team effort is necessary to handle the many quality control measures required in each of these areas.

Planning. Detailed planning of the cementing operation must begin far in advance of reaching casing setting depth. Ideally, the first planning meeting with service company personnel is held a few weeks before the job. Frequent contacts and checks must be made with the service company regarding slurry design, planned mixing and pumping schedules, and displacement requirements. Equipment requirements and spotting on location are included. Finally, about a week before the

job, a major meeting involving all participants (service company, drilling contractor, and operator) is required to review the entire cementing operation. Safety meetings and detailed briefings are held on location before each operation.

The major areas of consideration in job planning are slurry design, blending of bulk materials, slurry mixing, well preparation, and slurry pumping.^{1,2} Each area requires special attention and offers many challenges. Other aspects of job planning (discussed in Chapter 3) include casing equipment such as floats, centralizers, packers, etc. Planning in these other areas must be coordinated with overall job planning.

A properly engineered slurry design satisfies all well requirements and is affected by well depth, down-hole temperature, down-hole fracture pressure, slurry density, gas migration, fluid loss, pumping time, strength development, type and quality of mix water, type and density of drilling mud, displacement flow regime, and brand and kind of cement. The design proceeds in a logical manner from one slurry property to the next until all well requirements are fulfilled. The literature contains procedures for determining most of these properties.^{1,3} Steps leading to successful slurry design are (1) determining wellbore geometry, mud weight, type of mud, cement column height, and types of exposed formations (such as salt); (2) determining the down-hole fracture pressure for selecting maximum slurry density and maximum pump rate; (3) determining the down-hole temperature (static and circulating); (4) determining whether specific conditions exist that require fluid loss control, gas migration prevention, etc.; (5) estimating pumping time, safety factor and flow regime (Chapter 4); and (6) selecting initial slurry design for testing.

Wellbore Geometry. Before a cement slurry can be designed, information about the wellbore must be collected. This includes wellbore geometry, mud weight,

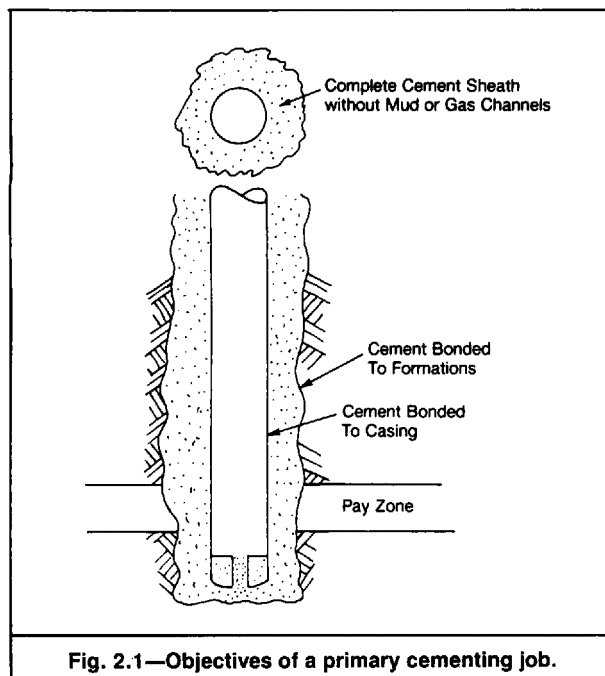


Fig. 2.1—Objectives of a primary cementing job.

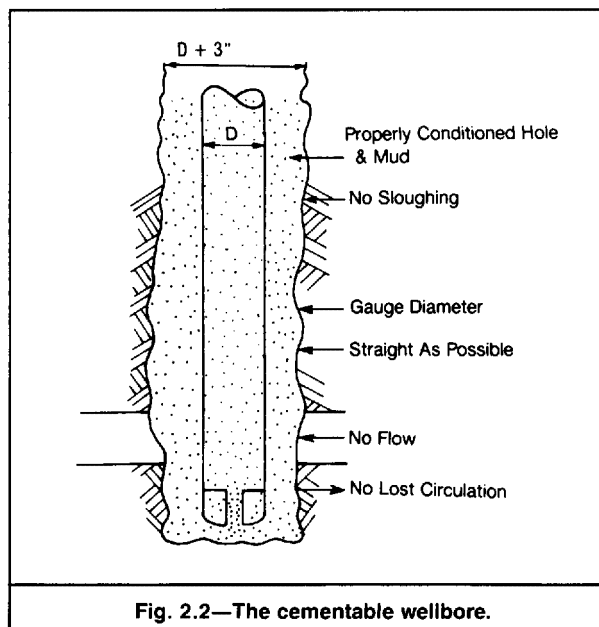


Fig. 2.2—The cementable wellbore.

type of mud, cement column height, and types of formations exposed to the wellbore. The wellbore should meet certain requirements to be cementable and achieve the desired objectives. This portion of cement job planning begins long before the well is drilled. Of utmost importance in all planning and drilling decisions is the objective of obtaining complete zonal isolation in the wellbore (Fig. 2.1). A hydraulic seal must be obtained between the cement and the casing and between the cement and the formation; at the same time, mud and gas channels within the cement sheath must be prevented. If these goals are to be accomplished, the wellbore must be designed and drilled to be cementable. The ideal cementable wellbore (Fig. 2.2) is one that is (1) 3 in. larger than the outside diameter of the casing (the absolute minimum is 1½ in. larger),^{4,6} (2) as nearly gauge as possible (without washouts), (3) as straight as possible (without severe doglegs), and (4) stabilized and properly conditioned (without sloughing, flowing, or losing circulation). Drillers must keep these requirements foremost in all plans.

It is imperative that the cementable wellbore not be sacrificed in the efforts to reduce drilling days and mud costs. The cost of repairing the cement job can far exceed savings in drilling costs. Lost production and lost reserves must also be included in any analysis of costs.

2.3 Cement Slurry Density

Fracture Pressure. The formation fracture pressure at the last casing point or at weak formations must be known to enable optimization of cement slurry density. During the planning stage of drilling a well, tentative decisions must be made about casing seats, mud weights, and cementing requirements. The decisions become more firm as more information becomes available during drilling. Sufficient knowledge of formation fracture pressure, pore pressure, and lithology is required not only to

optimize the casing and drilling plan, but also to provide for a successful cementing job. Casing setting depths must be selected to prevent lost circulation problems and to permit proper control of the well at all times. It becomes imperative, therefore, for the designer to know the total hydrostatic pressure at which exposed formations will fracture.

For safe operations, formation fracture pressure is defined for cementing purposes as the fracture extension pressure. It should not be confused with fracture initiation pressure, which is usually higher because of the tensile strength of the exposed rocks. However, since rock strength can not be accurately measured in situ, fracture initiation pressure can not be predicted very accurately. Figure 2.3 presents two formation control capability tests that show the difference between fracture initiation pressure and fracture extension pressure. The tests were conducted about 1 hour apart on an 8000-ft well. Note on Test 2 the absence of a breakdown or fracture initiation pressure, yet fracture extension pressure on the two tests remained essentially unchanged. In Test 1, fracture initiation pressure was about 450 psi or 1 lb/gal higher than fracture extension pressure. It appears that once the formation has been broken, this extra pressure due to rock strength can no longer be counted on for control of the well. It seems possible that during normal drilling operations the formation could be broken unintentionally without its being indicated at the surface. Designing for maximum slurry density on the basis of initiation pressure could easily lead to lost circulation during the cementing job. Therefore, the fracture extension pressure should be considered the maximum safe pressure for cementing.

Formation fracture pressure is affected by the interrelationship of overburden stress, pore pressure, and matrix stress coefficient, as given by the following expression:^{6,9}

$$p_f = p_p + K (S_{ov} - p_p), \dots$$

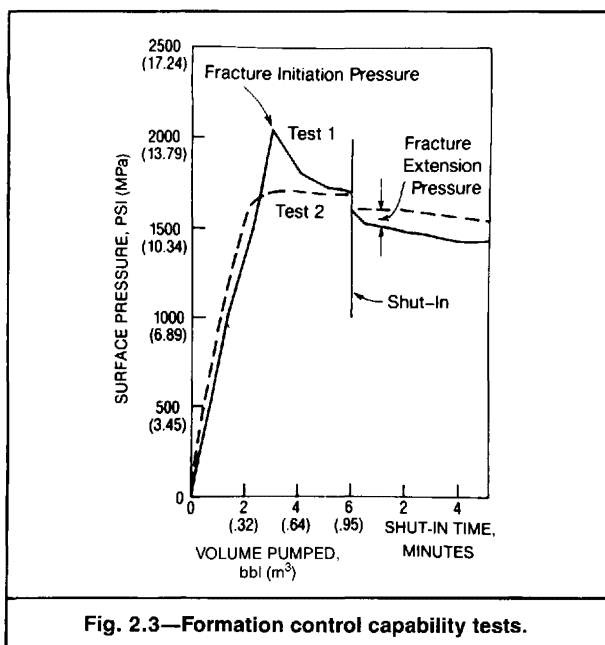


Fig. 2.3—Formation control capability tests.

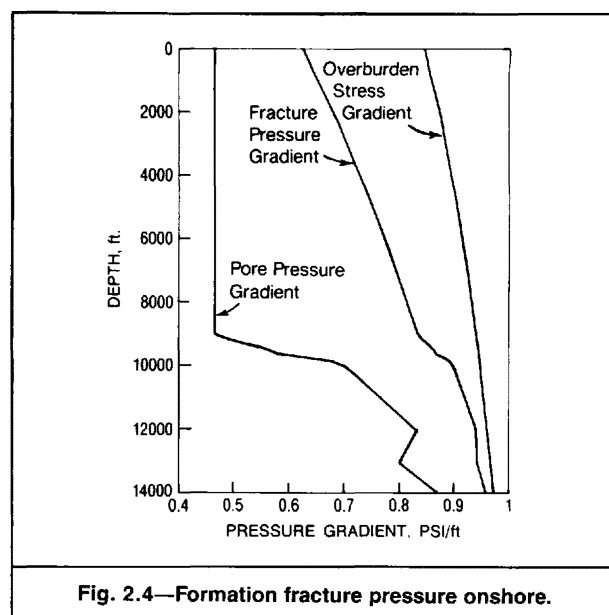


Fig. 2.4—Formation fracture pressure onshore.

where: p_f = formation fracture pressure, psi,
 p_p = formation pore pressure, psi,
 S_{ov} = overburden stress, psi,
 K = matrix stress coefficient, dimensionless.

To obtain a reasonable prediction of formation fracture pressure using Eq. 2.1, representative estimates must be obtained for overburden stress, formation pore pressure, and matrix stress coefficient. Overburden stress is obtained from formation density logs, and pore pressure is usually obtained from empirical correlations using wireline log parameters and measured pore pressures for the drilling area.¹⁰ However, the matrix stress coefficient (K) must be determined from actual destructive testing of the formation (i.e., hydraulic fracturing, or formation control capability testing at the casing shoe where the formation was fractured) or from leakoff test data. Care must be exercised in developing empirical correlations for stress coefficient. Usually, it is back-calculated from Eq. 2.1 when the other parameters are known. The value of formation fracture pressure, p_f , must be the value of fracture extension pressure determined in the destructive test. For some active drilling areas, a correlation has been developed by Matthews and Matthews.⁸

Sometimes Poisson's ratio⁹ is used in place of the stress coefficient, however reliable values for Poisson's ratio are not always available. An updated procedure for determining down-hole fracture pressure from which maximum slurry density can be obtained is presented in Reference 8.

An example curve representing a calculated onshore fracture pressure gradient in relation to curves of overburden stress and pore pressure is shown in Fig. 2.4. Notice that overburden stress, which is calculated from density logs, is not constant. Also, for offshore application, the fracture pressure gradient must be adjusted for depth of water and height of mud return line above water level.¹¹

Casing Setting Depths. Casing setting depths must be selected to ensure that the well can be controlled and that lost circulation can be prevented during both drilling and cementing. Assuming an overbalanced drilling situation, a mud weight curve is established, as shown in Fig. 2.5. From this curve and the fracture pressure curve, casing seats can be selected (Fig. 2.5). Maximum and minimum setting depths for surface casing are often dictated by (1) the regulatory body having jurisdiction over the drilling area, and (2) established field rules. Also, guidelines are often given for pressure gradients for the other casing strings; therefore, these requirements, field rules, and guidelines must be followed in selecting the final casing string setting depth and size program.

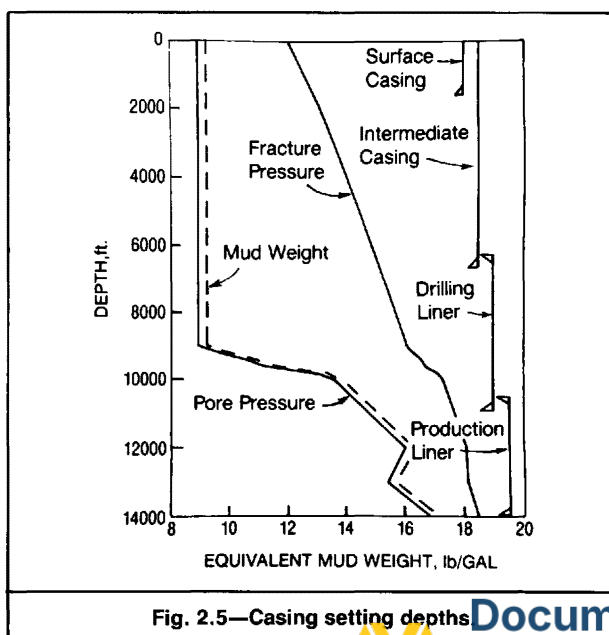
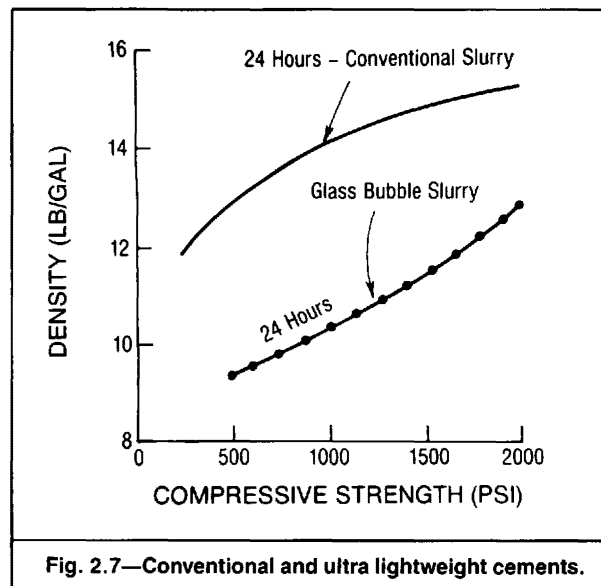
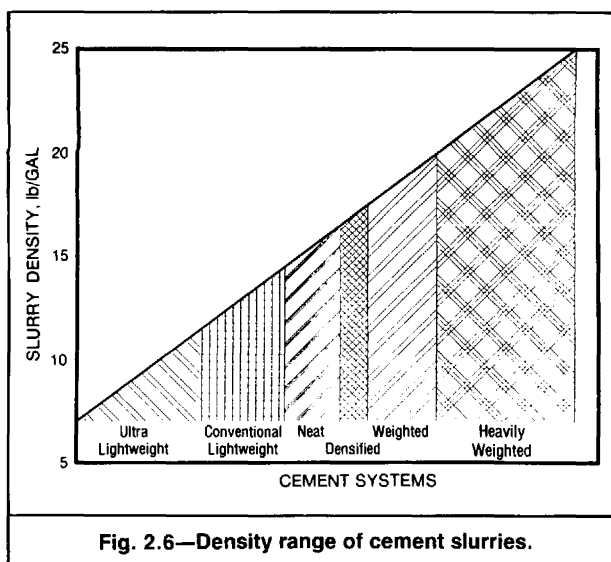


Fig. 2.5—Casing setting depths



Selecting Slurry Density. For a casing program like that of Fig. 2.5, the maximum slurry density to prevent losing circulation would be (1) about 17.5 lb/gal for the production liner, (2) nearly 15 lb/gal for the drilling liner, and (3) 11.5 to 12.5 lb/gal filler slurry followed by 15.8 lb/gal tail-in slurry for the intermediate string.

If the down-hole fracture pressure will not support the hydrostatic head of the required cement column, consideration should be given to using stage cementing tools. The process of selecting slurry density is the same for a stage tool as it is for the long string cementing described above. Stage tools are discussed in Chapters 3 and 4.

Determination of optimum slurry density involves considerable effort, but the extra effort can pay dividends in successful cementation of the well.

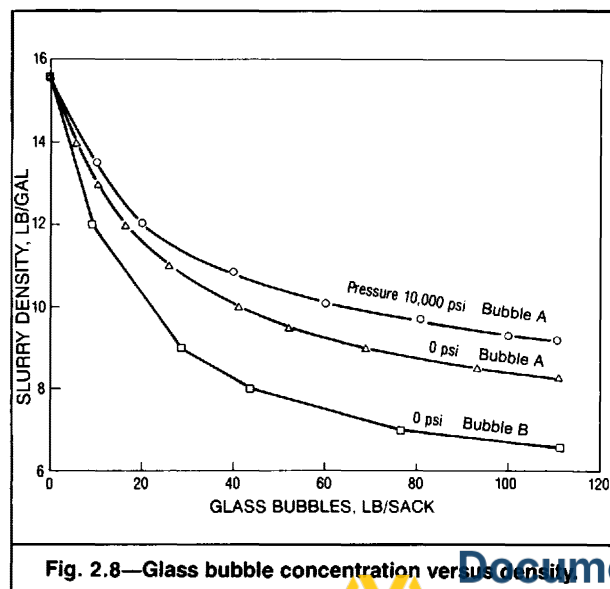
A wide range of slurry densities can be obtained using the nine API classes of cement, other non-API cements, and various additives.⁴ Figure 2.6 shows slurry densities of a generalized grouping of cements ranging from neat (with no additives) to cements variously weighted with additives that alter density. Each group has distinct advantages and properties. Laboratory testing will determine the upper and lower limits for application.

Conventional lightweight cement additives are important in lowering cement slurry density to prevent fracturing down-hole formations and to decrease slurry costs. These additives, such as bentonite, diatomaceous earth, and sodium silicate, are used to extend a cement, i.e., increase yield and reduce density by allowing use of high concentrations of mix water. A neat cement system (cement and API water requirement), however, has certain properties which are directly affected by additives and additional water. The most important of these properties is reduced strength; as shown in Fig. 2.7, the strength reduction associated with lower density is significant.¹² Based on compressive strength development, the usable minimum slurry density for conventional additives is about 11.5 lb/gal.

Many well situations require densities lower than those attainable with the above conventional high water additives. Shallow formations like those encountered in off-

shore conductor and surface pipe operations, onshore coal seams, and naturally fractured formations, require densities as low as 7 lb/gal. Ultra lightweight additives¹² developed for these applications include (1) hollow microspheres such as glass bubbles (boro or sodium silicate), (2) ceramic bubbles, and (3) nitrogen to foam the cement. These products allow achievement of in-situ slurry densities as low as 7 lb/gal and perhaps lower. The strength of these lower density cements is more than adequate to support casing, and in some cases even for perforating opposite pay zones. Figure 2.7 also shows strength characteristics of some ultra lightweight glass bubble slurries.

Figure 2.8 shows slurry density versus glass bubble concentrations for two glass bubbles, one for shallow wells and one for extremely deep wells. Since some microspheres are crushed as pressure is applied in the well, slurry density increases; this increase in density must be



accounted for in the design phase. To illustrate breakage of bubbles, Fig. 2.8 shows the bubble concentration required at 10,000 psi for the high strength bubble. Compare the top curve with the second curve at 0 psi to observe the change in bubble concentration.

2.4 Thickening Time Testing

In all cementing operations, the cement slurry properties, (1) thickening time (pumping time), (2) strength development, (3) permeability, (4) fluid loss rate, (5) rheology, and (6) free water, are drastically affected by down-hole temperature and pressure.^{1,13} Of these, the most important is thickening time, which is defined as the elapsed time from initial mixing of the cement with water to achievement of a final consistency of 100 Bearden Units (Bc). A Bearden Unit is a dimensionless unit of measure used to designate the consistency of a cement slurry. This unit is a torque-weight equivalent in the calibration procedure for the high-pressure consistometer potentiometer. Since a cement slurry is a non-Newtonian fluid, it is incorrect to refer to its viscosity in poise, so the dimensionless Bearden Unit is actually a viscosity index.

To select a cement composition that will have adequate pumping time in the down-hole environment for casing and liner cementing, proper laboratory job simulations must be made. Usually, the simulation is conducted in a high-pressure, high-temperature consistometer where the cement slurry can be exposed to down-hole temperature and pressure. Several tests with varying concentrations of cement retarders are usually required until an adequate pumping time is obtained, but first it is necessary to determine down-hole temperature and pressure to use in the lab tests.

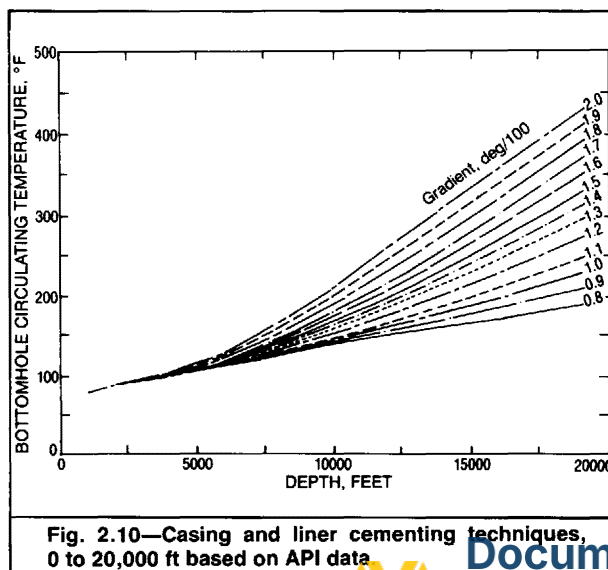
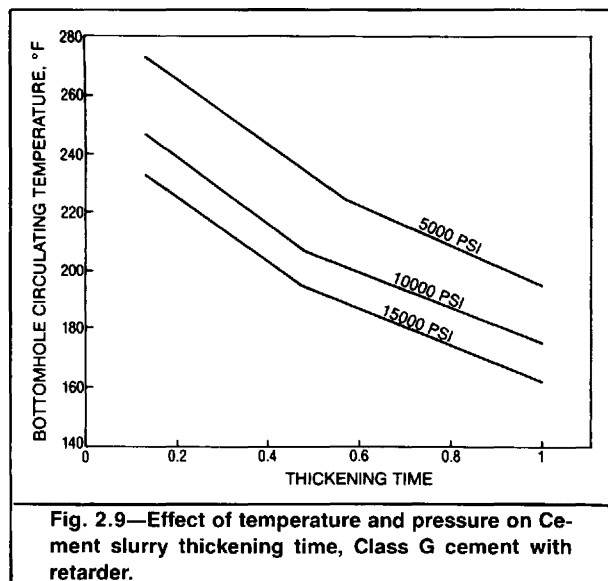
Down-hole Pressure. Accurate knowledge of down-hole pressure is required for laboratory consistometer simulation. The typical effect of pressure on cement slurry thickening time can be observed from the family of curves on Fig. 2.9, which were developed for a Class G cement with retarder. Notice that as down-hole pressure increases, the thickening time decreases. It is emphasized

that since the effect of pressure on the thickening time of any given slurry may be completely different than shown in this figure, it is important to include down-hole pressure in any lab simulations made. Pressure can be easily estimated from drilling mud weight and cement density, or standard pressure schedules developed by the API³ can be used in cement testing. These schedules are discussed in Section 2.3.

Cementing Temperature. Down-hole cementing temperature has a greater influence on reducing thickening time than does pressure, as shown in Fig. 2.9. It is therefore important to know down-hole temperature as accurately as possible. However, unlike pressure, the down-hole circulating temperature for testing is not always readily available. Sources of down-hole temperature information are primary well logs, measured temperatures during circulation surveys prior to cementing, Horner plots, and local practices. Of these, the best source is a bottomhole circulation survey, followed next by using API schedules in conjunction with primary well logs of 24 hours or longer shut-in, and third, API data. The Horner plot method and local practices can be inaccurate and must be used with caution.

The API³ has developed, from actual well measurements, relationships between BHCT (bottomhole cementing temperature), and a pseudo BHST (bottomhole static temperature) for temperature gradients of 0.9 to 1.9°F/100 ft and for depths to 20,000 ft. These relationships have been expanded for this presentation to make them more complete. The expansion to include more gradients was made with a simple interpolation between the API gradients. These data are presented in Table 2.1 and are shown graphically in Fig. 2.10 for casing and liner cementing operations.

To use the API charts, a pseudo BHST rather than true static temperature is required because API measured values are not true static temperatures. The API pseudo BHST are the maximum shut-in temperatures measured with down-hole recording tools run on the drillpipe just before running and cementing casing (Fig. 2.11). For all



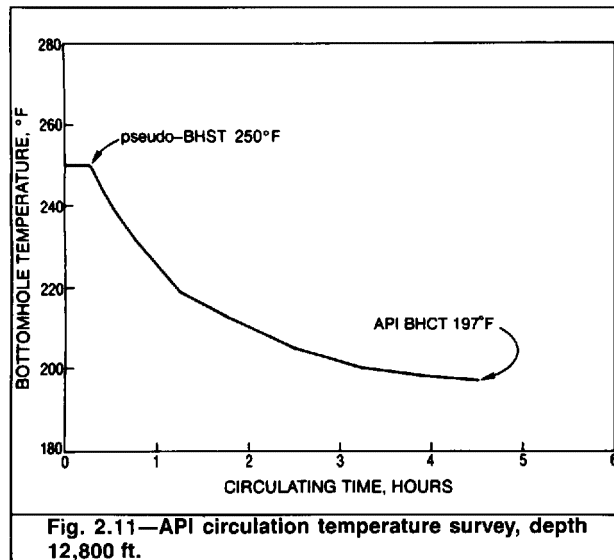


Fig. 2.11—API circulation temperature survey, depth 12,800 ft.

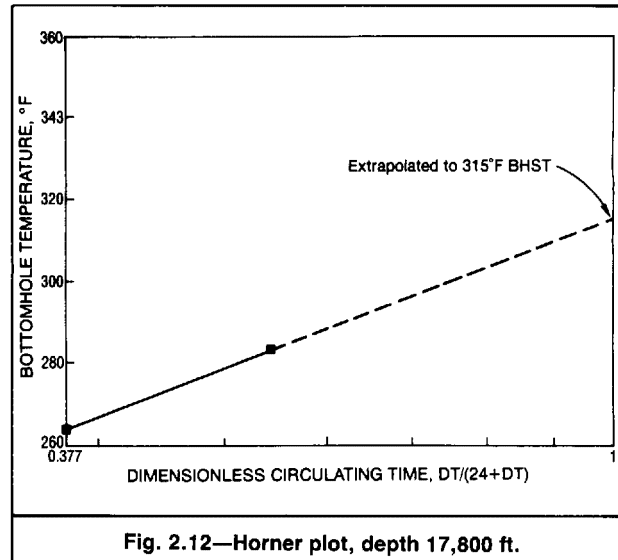


Fig. 2.12—Horner plot, depth 17,800 ft.

wells included in the API data, the shut-in time since the last mud circulation averaged 31 hours (range was 7 to 76 hours) when the temperature was measured. A much longer shut-in time than this is required to reach true static temperature; therefore, true static formation temperature must not be used with API data.

An example of temperatures measured during a field survey from which the API charts were developed is shown in Fig. 2.11. After monitoring the bottomhole shut-in temperature (pseudo BHST) for about 15 minutes, circulation of the well was begun. Notice that after about 4 hours of circulation time, the circulating temperature had nearly stabilized at 197°F. Similar BHCT and pseudo BHST data for many wells were correlated with temperature gradient and depth to develop the API cementing temperatures.

An example will illustrate the use of well logs and API temperature data for determining BHCT for use in cement testing. A well at 12,000 ft has a BHLT (bottomhole log temperature) of 272°F after 24 hours shut-in since the last mud circulation. For casing or liner cementing, either Table 2.1 or Fig. 2.10 can be used for determining BHCT. A temperature gradient of 1.6°F/100 ft is calculated from the following equation.

$$\text{Temperature gradient} = (\text{BHLT} - 80)/(\text{depth}/100) \dots (2.2)$$

where

Temperature gradient = Temperature change with depth, °F/100 ft

BHLT = Bottomhole log temperature, °F

Depth = Well depth of measured temperature, ft.

By entering Fig. 2.10 at 12,000 ft on the X-axis and moving vertically to a temperature gradient of 1.6, then left to the Y-axis, the BHCT should be used in cement testing is found to be 207°F. In this case, Table 2.1 is easier to use. Enter Table 2.1 at 12,000 ft and move to right to 1.6 gradient, then read 207°F BHCT.

The Horner method is still used by some to arrive at a BHST, which is then used to determine a BHCT. This method is inappropriate for using API temperatures and schedules but is described here so the reader may beware.

In the Horner method,¹⁴ a BHST is calculated from at least two temperature measurements taken at different shut-in times at the same depth during logging operations. It uses an analytical extrapolation technique similar to Horner's pressure buildup technique. The basic criterion for the technique is the straight-line relationship (on semilog paper) of maximum bottomhole temperature versus the ratio of

$$\Delta t/(T + \Delta t), \dots (2.3)$$

where

Δt = shut-in time since last circulation ceased for temperature measurement, hours

T = circulation time prior to shut-in, hours.

The log of the above ratio is plotted versus linear temperature measured during logging operations. The straight line between at least two points is extrapolated to a log ratio of 1.0 for the BHST.

The BHST calculated by the Horner method is always significantly higher than the pseudo-BHST required for using API charts. The corresponding BHCT determined by using the BHST calculated from the Horner plot will be much higher also and will result in overretardation of the cement slurry and long WOC (waiting-on-cement) times.

In the following example for a 17,800 ft casing cement job, a comparison is made between the Horner plot, primary well logs and API data, and an actual down-hole circulating survey for determining BHCT. Measured log temperatures were 264°F after 14.5 hours shut-in and 283°F after 28.5 hours shut-in. Prior to shut-in for logging, the well had been circulated for 24 hours during drilling. For each of the temperatures, Eq. 2.3 is used to calculate a ratio of 0.377 for the first log time of 14.5 hours and 0.543 for the second log time of 28.5 hours.

TABLE 2.1 — BOTTOMHOLE CEMENTING TEMPERATURE BY DEPTH³

		Temperature Gradient, °F/100 ft												
Well Depth	Temp*	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.5	1.6	1.7	1.8	1.9	2.0
		Temperature, °F												
1000	BHCT	80	80	80	80	80	80	80	80	80	80	80	80	80
	BHLT	88	89	90	91	92	93	94	95	96	97	98	99	100
2000	BHCT	89	89	89	89	90	90	90	90	91	91	91	91	91
	BHLT	96	98	100	102	104	106	108	110	112	114	116	118	120
3000	BHCT	94	94	94	95	95	96	96	96	97	97	97	98	98
	BHLT	104	107	110	113	116	119	122	125	128	131	134	137	140
4000	BHCT	99	99	100	100	101	101	102	102	103	103	104	104	105
	BHLT	112	116	120	124	128	132	136	140	144	148	152	156	160
5000	BHCT	105	106	106	107	108	109	109	110	111	112	113	115	117
	BHLT	120	125	130	135	140	145	150	155	160	165	170	175	180
6000	BHCT	111	112	113	114	115	116	117	118	119	120	123	126	129
	BHLT	128	134	140	146	152	158	164	170	176	182	188	194	200
7000	BHCT	118	119	120	122	124	126	127	129	131	133	138	143	148
	BHLT	136	143	150	157	164	171	178	185	192	199	206	213	220
8000	BHCT	125	126	128	129	132	135	138	140	143	146	153	160	167
	BHLT	144	152	160	168	176	184	192	200	208	216	224	232	240
9000	BHCT	132	134	136	138	142	147	150	154	158	163	172	180	189
	BHLT	152	161	170	179	188	197	206	215	224	233	242	251	260
10,000	BHCT	139	141	144	146	152	158	163	167	174	180	190	200	210
	BHLT	160	170	180	190	200	210	220	230	240	250	260	270	280
11,000	BHCT	144	148	152	156	164	172	177	182	190	199	211	224	236
	BHLT	168	179	190	201	212	223	234	245	256	267	278	289	300
12,000	BHCT	150	155	160	165	175	185	191	197	207	217	232	247	262
	BHLT	176	188	200	212	224	236	248	260	272	284	296	308	320
13,000	BHCT	155	162	169	176	188	200	208	215	226	238	254	270	286
	BHLT	184	197	210	223	236	249	262	275	288	301	314	327	340
14,000	BHCT	160	169	178	187	201	215	224	233	246	258	276	293	311
	BHLT	192	206	220	234	248	262	276	290	304	318	332	346	360
15,000	BHCT	165	176	187	199	214	230	241	252	266	280	298	317	335
	BHLT	200	215	230	245	260	275	290	305	320	335	350	365	380
16,000	BHCT	170	183	197	210	228	245	258	270	286	302	321	340	359
	BHLT	208	224	240	256	272	288	304	320	336	352	368	384	400
17,000	BHCT	176	191	207	222	242	261	275	289	307	325	344	363	382
	BHLT	216	233	250	267	284	301	318	335	352	369	386	403	420
18,000	BHCT	182	199	217	234	256	277	293	308	328	347	366	385	404
	BHLT	224	242	260	278	296	314	332	350	368	386	404	422	440
19,000	BHCT	187	207	227	247	271	295	311	328	349	370	389	408	427
	BHLT	232	251	270	289	308	327	346	365	384	403	422	441	460
20,000	BHCT	193	215	237	259	286	312	330	348	370	392	412	431	451
	BHLT	240	260	280	300	320	340	360	380	400	420	440	460	480

* BHCT is the bottomhole circulating temperature.

BHLT is the bottomhole log temperature after 24 hours shut-in.

The log of these values versus measured temperature is plotted in Fig. 2.12. Extrapolating the straight line from these two points to a log ratio of 1.0 yields a BHST of 315°F. Referring to Table 2.1 and a 1.3 temperature gradient (from Eq. 2.2), an API BHCT of 277°F is shown for a BHST of 314°F. This BHCT is 40° higher than the circulation survey BHCT of 237°F shown for the same well on Fig. 2.13. The 6-hour circulation survey followed 50 hours shut-in for logging operations.

A better estimate (than the Horner plot) of BHCT can be made using the 28.5-hour shut-in log temperature of

283°F and the API charts. Since the shut-in time is more than 24 hours, this BHLT can be considered a pseudo BHST for cementing purposes. From either Table 2.1 or Fig. 2.10, an API BHCT can be interpolated between the 1.1 and 1.2°/100 ft temperature gradient at 18,000 ft. The corresponding BHCT is 240°F, which compares very closely with the 237°F measured on the circulation survey (Fig. 2.13).

This comparison confirms, as do many others not included here, that the Horner method should not be used for determining BHCT from the API data for cement testing.

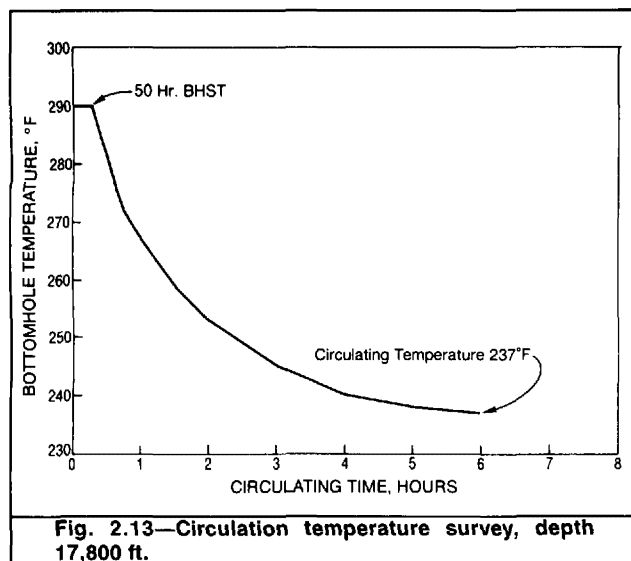


Fig. 2.13—Circulation temperature survey, depth 17,800 ft.

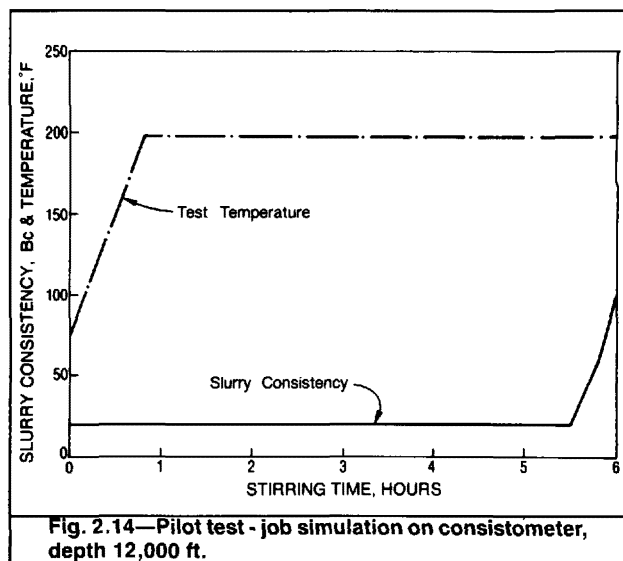


Fig. 2.14—Pilot test - job simulation on consistometer, depth 12,000 ft.

In some areas, the local practice is to use a method which results in a BHCT that is too high. The BHLT is increased by 5% to 15% to arrive at a BHST; then, either the API tables or other correlations are used for estimating BHCT. This method also is inappropriate because it can result in a high BHCT which results in overretardation of the cement slurry and long WOC times.

An example from a Gulf Coast liner cementing job illustrates how inaccurate this technique can be. Well logs at 14,900 ft showed a BHLT of 291°F after 24 hours since the last circulation. One company extrapolated this to 315°F BHST at 15,300 ft (liner setting depth). From API correlations, a BHCT of 270°F was selected. Laboratory consistometer tests were conducted on the cement slurry until a thickening time of 5½ hours was obtained at 270°F at 15,300 ft. This required a high concentration of retarder. When compressive strength tests for the liner top at 12,400 ft were run, the slurry was not set within 55 hours WOC time. Thus, this method for BHCT resulted in overretardation and a long WOC time.

A better method for determining BHCT in this case is to use the 24-hour shut-in log temperature of 291°F as a pseudo BHST at 14,900 ft. Extrapolating this to 15,300 ft (liner setting point), the pseudo-BHST is 297°F. Using the API data from Table 2.1, a BHCT of 246°F is determined by interpolating between the temperature gradients of 1.4 and 1.5 at 15,000 ft. Note that this temperature is 25°F below the previous estimate. Subsequent testing at this temperature resulted in a mixing of slurry having much less retarder; there was no overretardation of the slurry nor long WOC time at the lower temperature that existed at the top of the liner.

The local method for estimating circulating temperature should be avoided in cement testing, since it often is in error by a high percentage.

From the above comparisons, it is obvious that the best source for obtaining BHCT is a down-hole circulation survey near the casing setting depth. In the absence of a circulation survey, the BHCT for cement testing can be determined using (1) log temperatures obtained approximately 24 hours since the last mud circulation and (2) API values from Table 2.1 or Fig. 2.10. If the only log temperatures available are obtained much sooner than 24

hours since the last mud circulation, a circulation survey should be conducted to determine the BHCT.

After determining the appropriate BHCT, a laboratory consistometer simulation must be conducted following a particular test schedule for temperature and pressure. The consistometer exposes a cement slurry formulation to temperature and pressure similar to the actual environment of the slurry as it is pumped down the well. The schedules in API Spec 10 can be used for this purpose. For the earlier example of a 12,000-ft casing cement job simulation, API Schedule 7g can be used. This schedule is reproduced here as Table 2.2. On this table, locate the column for the calculated 1.6°/100-ft temperature gradient. Interpolating for this gradient on Table 2.2 shows that the temperature of the cement slurry would be increased from 80°F to 207°F in 44 minutes. The corresponding pressure increase schedule is shown in Column 2 for a 14 lb/gal drilling mud. The final temperature of 207°F and final pressure of 10,200 psi are maintained constant throughout the remainder of the test. The test is completed when the slurry consistency reaches 100 Bc. Figure 2.14 shows curves for temperature and slurry consistency for a cement tested on the 12,000-ft schedule determined above. The thickening time to 100 Bc is 6 hours.

Determining whether this slurry is satisfactory for the example job requires knowledge about the job time, the type of mixing, and safety factor desired. As a general rule, a cement slurry should be in place behind the casing and the job completed at least 1 hour before the slurry reaches a consistency of 50 Bc. Hartog, et al.¹⁵ suggest an even lower value of 40 Bc. Figure 2.15 shows the minimum acceptable thickening time, taking into account job time, mixing-on-the-fly, and a 1-hour safety factor.

If the cement slurry is to be batch mixed, then this extra time at the surface must be included in the consistometer test. To simulate batch mixing, the slurry is simply stirred in the consistometer at 80°F for 1 hour, or the estimated batch mixing time, before increasing temperature and pressure following the chosen schedule as shown on Fig. 2.16. For wells with a low BHCT, it is most important that the batch-mix time be simulated in the

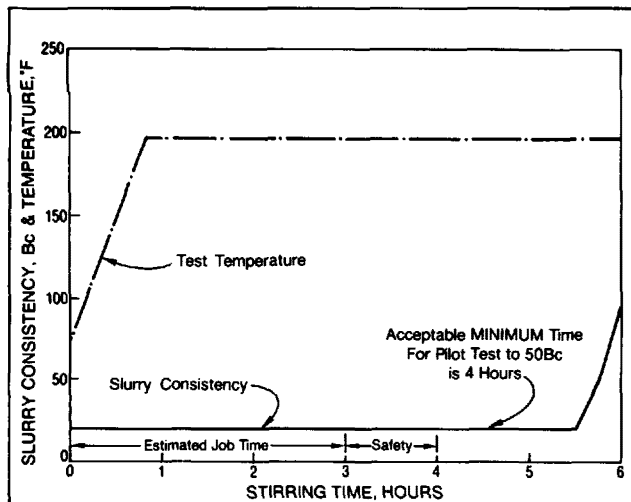


Fig. 2.15—Pilot test - job simulation on consistometer, depth 12,000 ft.

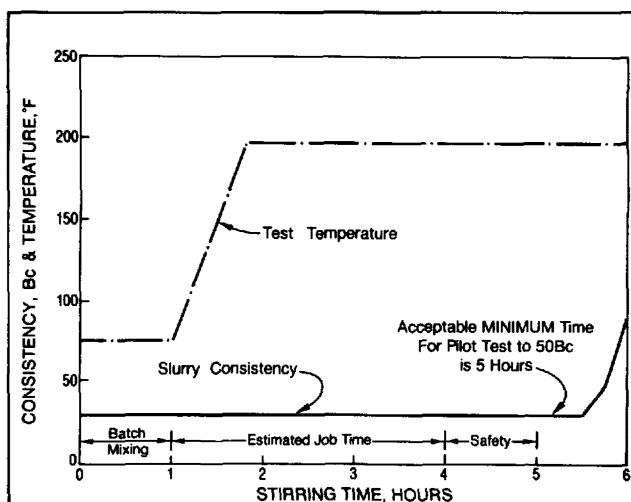


Fig. 2.16—Pilot test - batch mixing job simulation on consistometer, depth 12,000 ft.

consistometer test because 1 hour of mixing at the surface can shorten the thickening time almost as much as 1 hour of mixing at low down-hole cementing temperatures. This simple analysis will show if the selected slurry is satisfactory for the job with either type of mixing.

After the selected cement composition has been blended at the service company yard for the intended job, it is recommended that a consistometer test be run on some, if not all, cement blends on critical jobs or for wells drilled deeper than 8000 ft. If time does not permit consistometer tests to be run, then consideration should be given to running a chemical thickening time test on each blend.¹⁶ This is to ensure that the additives are present in the proper ratio and that the cement slurry will perform at designed conditions down-hole. Figures 2.17 and 2.18 show examples of acceptable times for blend tests. If the blends do not meet the specified well requirements, additional blending and testing are required.

The BHCT for casing and liner cementing jobs is the same; however, the heat-up schedule for liners is faster than for casings. This is because on liner jobs, cement is pumped down drillpipe and reaches the bottom of the hole faster than for casing jobs.

2.5 Compressive Strength Testing

Strength requirements of cements are dependent on many factors. Generally, the cement must have sufficient strength to (1) support and secure the casing in the hole,^{1,2} (2) achieve zonal isolation in the wellbore, (3) prevent communication of fluids behind the casing, and (4) withstand the shock of drilling, perforating, and fracturing.

Very little strength is needed to support pipe. A minimum compressive strength of about 100 psi is all that is needed to support and secure the casing in the hole; however, this does not eliminate the need for higher strength later on in the life of the well. For most surface

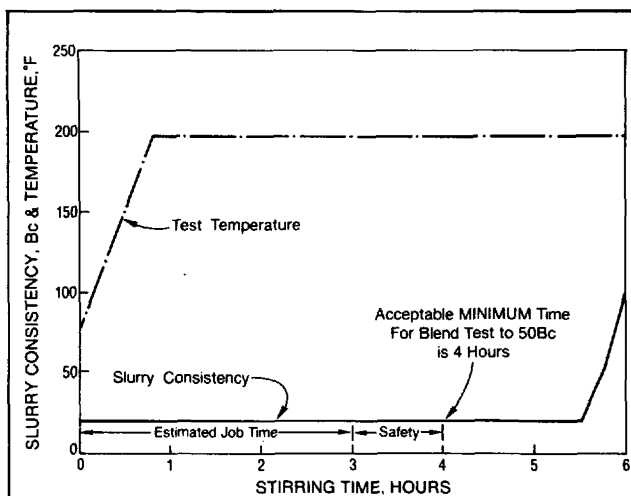


Fig. 2.17—Blend test - job simulation on consistometer, depth 12,000 ft.

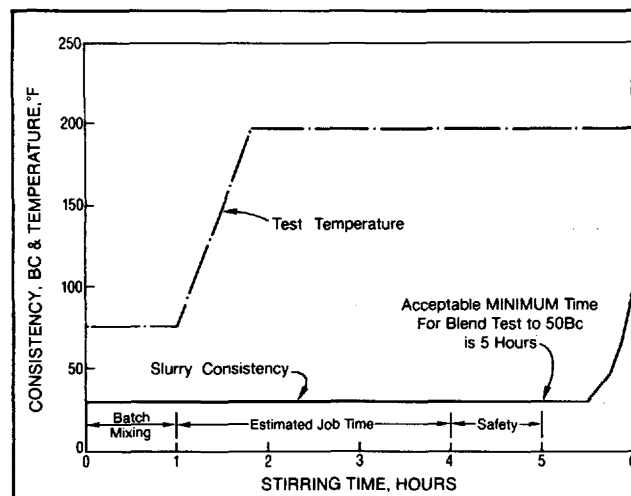


Fig. 2.18—Blend test - batch mixing job simulation on consistometer, depth 12,000 ft.

TABLE 2.2 — BOTTOMHOLE CIRCULATING TEMPERATURE BY TIME AT 12,000 FT DEPTH³

Time, Min	Pressure, psi	Temperature Gradient, °F/100 ft depth					
		0.9	1.1	1.3	1.5	1.7	1.9
		Temperature, °F					
0	1500	80	80	80	80	80	80
2	1900	84	84	85	85	86	88
4	2300	87	88	89	91	93	96
6	2700	91	92	94	96	99	105
8	3100	94	95	99	102	106	113
10	3500	98	99	103	107	112	121
12	3900	101	103	108	113	118	129
14	4300	105	107	113	118	125	137
16	4700	108	111	117	124	131	145
18	5100	112	115	122	129	138	154
20	5500	115	119	127	135	144	162
22	5900	119	122	131	140	150	169
24	6300	122	126	136	145	157	176
26	6700	126	130	141	151	163	183
28	7100	129	134	146	156	170	190
30	7500	133	138	151	162	176	197
32	7800	136	142	156	167	183	204
34	8200	140	146	161	172	189	211
36	8600	143	150	166	177	195	218
38	9000	146	153	171	182	202	228
40	9400	149	157	176	187	207	232
42	9800	152	161	180	192	212	239
44	10,200	155	165	185	197	217	247
Heating Rate °F/min		1.70	1.93	2.39	2.66	3.11	3.80

NOTE: Mud density used was 14 lb/gal.

and intermediate strings it is the usual practice to use high-strength cement around the shoe joints and lower-strength, lower-cost filler cements around the upper portions of these strings. The higher-strength cements around the shoe joints also contribute to savings because they shorten WOC (waiting on cement) time before shoe joints can be drilled.

The capability of a cement sheath to resist communication during fracturing and subsequent producing operations is dependent, among other factors, on the strength of the cement. Because of the uncertainty in correctly simulating down-hole conditions in the laboratory, the most widely used minimum strength required for any operation is 500 psi in 24 hours at down-hole static temperature. Where closely-spaced zones during stimulation operations are of concern, cement of high ultimate strength should be used. When using expendable jet perforators a minimum compressive strength of 2000 psi may be required.

Temperature has a pronounced affect on strength development. Up to 230°F, increasing temperature increases strength; however, at higher temperatures strengths are decreased. Figure 2.19 illustrates this phenomenon for three different cements using 24-hour compressive strength values. This same trend is also usually observed at longer curing periods. This strength retrogression is thought to be caused partially by large particle size growth during the hydration process at the higher temperatures.^{17,18} The addition of silica to the cement formulation prevents strength retrogression, as shown in Fig. 2.20. An industry survey conducted by API¹⁷ re-

vealed that most companies routinely add 35% silica to cement at static temperatures of 230°F and above.

Note in Fig. 2.19 that very low strengths are indicated at temperatures below 80°F. To increase early strength development and shorten WOC time at the lower temperatures, calcium chloride is usually added to the cement recipe.

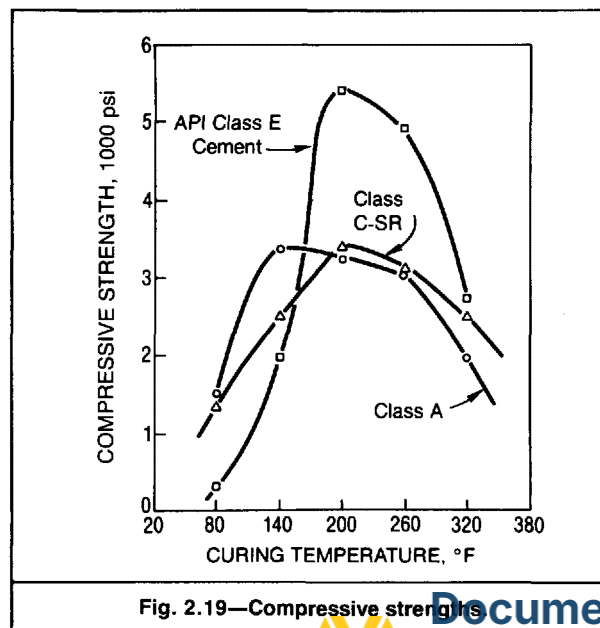


Fig. 2.19—Compressive strength



Documents

Document Sharing Hub

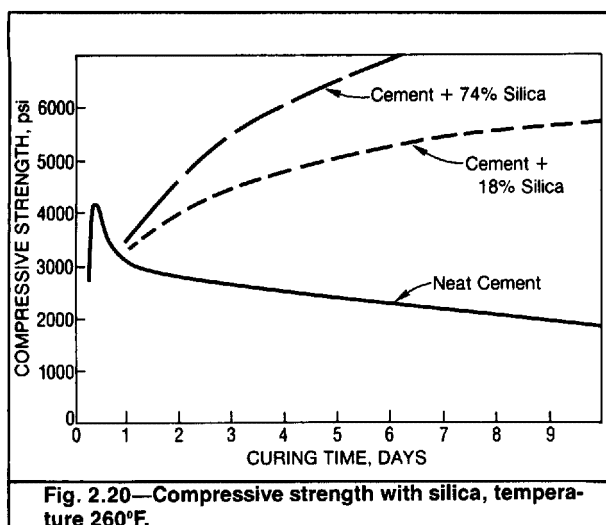


Fig. 2.20—Compressive strength with silica, temperature 260°F.

The ultimate strength of a given cement in a well is a factor over which little control can be exercised. If the slurry is mixed at the proper water:cement ratio, the slurry will be readily pumpable, and will generally develop adequate strength. Excessive water:cement ratios and high additive content decrease strength.

2.6 Permeability

The final permeability of a neat cement, much like its strength, is a factor over which little control can be exercised. As a general rule, the finer the grind the lower the permeability, however, this trend is often balanced by the larger amounts of water required to form a pumpable slurry with finer grinds. Increasing water also increases permeability.

Temperature affects permeability in much the same manner in which it affects strength. The same process that causes strength retrogression also causes high permeability development in cements, as shown in Fig. 2.21. Adding silica to the cement also prevents high permeability development.¹⁷

2.7 Fluid-Loss Testing

Another important cement slurry property to control is fluid-loss rate. Additives are available to control the fluid-loss rate of the cement and maintain the proper water:cement ratio. These additives prevent slurry dehydration. For a cement to be pumpable, water content above that required for proper hydration is required. Some or all of this excess water can be easily squeezed from the slurry if the cement encounters a permeable formation in the wellbore during the cement job. The loss of only a portion of this water can significantly alter cement properties. Thickening time, for example, is decreased with water loss. At the greater depths where longer pump times are required, thickening times must be predictable. Any change in the water ratio down-hole can so drastically reduce the thickening time that the job may be terminated prematurely. If a high portion of the excess water is squeezed from the slurry, the cement may experience what many call a "flash set." At this point, the

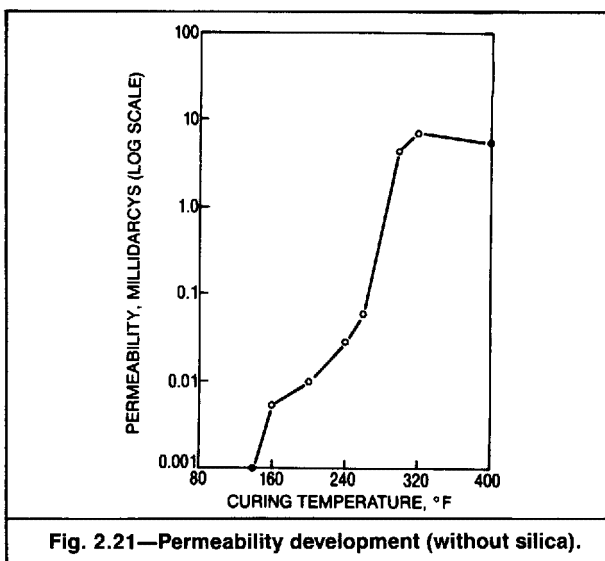


Fig. 2.21—Permeability development (without silica).

cement is no longer pumpable, and the job is terminated prematurely. Fluid-loss additives "tie up" the excess water and prevent it from being squeezed from the slurry.^{19,20} Usually, when a job is terminated prematurely, remedial work is required.

The fluid-loss test is conducted in accordance with API procedures by exposing the cement slurry to test temperature and a differential pressure of 1000 psi for 30 minutes. The amount of filtrate recovered in 30 minutes is measured. A choice of cells is provided for the user. For static testing, cells having a slurry volume of 250 cc to 400 cc are available. The larger cell volume is the most accurate for all fluid loss rates, whereas in the smaller volume cell the slurry can completely dehydrate before the 30 minute test period is up. Extrapolating the results to equivalent 30 minute values can be misleading; therefore, the best choice is the larger 400-cc cell.

For a more representative fluid-loss rate test, the stirring fluid-loss cell is recommended. This is a commercially available device which allows the slurry to be stirred in a large volume cell while the slurry temperature is increased to the simulated down-hole temperature. The cell is then inverted, and the fluid loss test is conducted. This cell is similar to the large API static cell but with the addition of the stirring and inverting capabilities.

Listed below are typical values for fluid-loss control rates versus field operation.⁴ For comparison, a cement slurry without fluid-loss additives has a fluid-loss rate of about 1000 cc/30 minutes.

- For casing cementing (if needed): 250 cc/30 minutes
- For liner cementing: 50 cc/30 minutes
- For prevention of gas channeling: 20 cc/30 minutes
- For squeeze cementing: 50 to 200 cc/30 minutes

Note: All fluid-loss determinations must be made at bottomhole *circulating* temperature except for preventing gas channeling, which is conducted at bottomhole *static* temperature.

2.8 Free Water Testing

The free water test is important because excessive free water can allow adverse conditions to develop in the down-hole region. For example, free water pockets in the cement sheath at casing collars and hardware can cause accelerated corrosion at these locations. Also, excess water can allow settling of weighting materials which, in turn, can cause bridging and gas migration. Other problems can occur with thickening time, strength, and other cement properties; therefore, free water should be held to a minimum.

The amount of free water will depend on the total mix water used in the slurry and the desired slurry consistency. The amount of mix water for a slurry will vary depending on the additives present in the recipe. There is a practical range of mix water content based on slurry consistency. Usually, the maximum consistency on mixing cement with water should be limited to near 30 Bc. Higher values than this may cause mixing and pumping problems. The lower end of consistency value can be determined by the free water test and a settling test. Often, the slurry consistency is lowered to achieve turbulent flow in the annulus at low pump rates. Perhaps a better way to achieve turbulence in the annulus is to use a properly designed spacer or preflush. This will allow the cement slurry to be designed to meet all the other important requirements for the well.

Typically, water for the cement portion of the slurry will follow the API specifications for each class of cement; this specification varies from 38 to 56%. The free water content of a slurry is determined in accordance with API specification 10. In this test, the slurry mixed with recommended water content is usually poured into a 250-ml cylinder and allowed to stand quiescent for 2 hours. The amount of supernatant water developed is designated the free water content. API sets free water specifications (1.4%) for only Class G and H cements as purchased from the manufacturer. For routine operations, this may be an acceptable value, but for liner cementing and prevention of gas channeling, the free water value should be zero. This low value can be achieved in the design phase of the cement job quite easily by adding 0.1% to 0.2% bentonite or other similar additive. Achievement of this value on the job requires close quality control of cement density.

2.9 Rheology Determination

Determination of rheological properties is usually done using a rotational viscometer. This device uses a concentric bob and rotor to shear the cement slurry in a small gap to arrive at the shear rate versus shear stress. API Spec 10 provides an excellent procedure for determining rheological properties of a cement slurry.

The cement system and spacer must be designed to achieve the desired mud displacement efficiency in the annulus without excessive pressure buildup due to friction. The most widely used models to determine flow regime are the power law model and the Bingham Plastic model; both are adequately described in API Spec 10. If the results of these calculations show excessive friction pressure or excessive pump rate requirements, the slurry should be redesigned to lower the rheology values.

Settling Tests. For slurries containing weighting mate-

rials such as hematite, the slurry should be checked to determine whether the rheological properties are adequate to suspend solids, not only at surface conditions during mixing, but also at the down-hole temperature and pressure. This is required to prevent solids settling and bridging while pumping, and to ensure placement of a competent and consistent cement column from top to bottom in the annulus. Excessive settling can cause down-hole plugging and premature termination of the job.

To verify that the slurry is capable of suspending solids, free water tests as described earlier should be conducted at surface conditions and at temperatures and pressures as close to bottomhole conditions as possible, and at the hole deviation angle. Slurries not passing this test should be redesigned.

In addition to the free water tests, settling tests should be run in the consistometer under bottomhole temperature and pressure. The settling test should be conducted in accordance with the procedure described in API Spec 10, Appendix P, Paragraph P.6. After completing the required three tests, and before terminating the procedure, the slurry cup should be removed from the consistometer and the condition of the slurry should be observed. Examine the slurry for settling, packing, gelation, and free water. Slurries failing this test should be redesigned.

2.10 Bulk Blending

Blending of the various additives and cement of the final design selection must be carried out with diligence to ensure that the ingredients are properly blended. The importance of this diligence becomes more evident when one considers that in some cement recipes as little as 50 lb of an additive is blended with 18,000 lb of cement.⁴ Altering an additive ratio or inadvertently leaving one additive out of the blend can have drastic consequences in the oven-like environment of a high-temperature well.

Blending of bulk materials often is taken for granted even though it is a process in which serious errors can occur undetected, and if not corrected, can lead to a cementing failure. After the cementing system has been carefully designed in the laboratory, the composition or recipe must be correctly blended to ensure proper slurry performance in the wellbore. The two major factors affecting this performance are the concentration and the distribution of additives in the cement blend.^{21,22} Small variations in concentrations of additive can significantly alter the performance properties of the cement slurry; therefore, quality control during this phase is extremely important.²³ Steps shown below should be carefully followed.²¹⁻²⁶

1. Visually inspect all bulk tanks before transferring any bulk material. Any cement remaining in tanks from previous jobs can contaminate a cement slurry to the point that it will not perform down-hole. A tank should be cleaned if it contains excess cement.

2. Verify the calculations of additive weights.

3. Verify the weights of all additives put into the batch tank for each blend. Count and stack the sacks of each additive placed in the cement blend.

4. Limit batch size to 50% of total tank capacity.

5. Verify air valve positions made by the operator.

6. Blend materials with air and transfer from smaller tanks at least three times.

7. Collect representative samples of the blend for analysis.

Close attention should be paid to the proper collection of samples. Although investigations into proper sampling techniques have been limited, the industry consensus is that three transfers of the blend should be made before sampling. With a continuous in-line sampling device, a representative sample can be taken of each blend. A minimum of two 1-gal samples of bulk material should be collected and identified for every weigh-tank batch.

After blending, laboratory tests should be conducted to determine the additive concentrations using the chemical method,¹⁶ or the thickening time using API procedures,³ at the expected down-hole temperature and pressure.

2.11 Job Execution

Surface Equipment and Devices. Surface equipment required for the cementing operation includes a cement head (plug container), pump trucks or skids, bulk material tanks, mix-water tanks, cement mixers, and a source of displacement fluid. On critical jobs, monitoring devices are needed. These may be an in-line radioactive densometer, flowmeters in the injection line and in the mud-return line, pressure transducer at the cement head, and a portable data recorder. Equipment must be located to minimize the length of all lines and to prevent confusion. Bulk tanks should be located near associated mixers to permit use of short bulk cement delivery lines to the cement mixers. The number of pumps required depends on the mixing method and pump rate. In any event, a standby pump truck or skid should be included and tied into the system to permit its immediate use if one of the primary pumps fails.

Container Heads. Container heads are available for single-plug, two-plug, and multiple-plug applications. The single-plug method requires a shut-down in the operation while the other two do not; since a shut-down is undesirable, the single-plug container is not recommended. The two-plug container is preferred over the single-plug head, but requires some special planning for its use. Usually the elevator bails are not long enough to accommodate the two-plug head; therefore, arrangements must be made ahead of the job for longer bails to be changed before the job. The multiple-head container is remotely operated and does not require shut-down to allow for dropping any of the several plugs it can hold (Chapter 3).

Mixers. The three types of mixers for mixing cement slurry are jet mixers, recirculating mixers, and batch mixers. The first two can be used to mix the slurry on-the-fly without a holding tank or can be directed into a batch mixer before the slurry is routed to the well. The most accurate method of mixing is to batch mix the cement slurry because the slurry can be mixed to proper density before the first barrel is pumped into the well. This is important, since density control usually is the only method that can be used to ensure that the cement recipe is correctly mixed. Once the cement slurry is routed to the wellhead, the slurry can not be changed (Chapter 4).

Density Devices. Density control is maintained with the pressurized balance. This device permits the most accurate measurement of density because it collapses all the entrained air that can cause an erroneous measurement by as much as 1 lb/gal. A radioactive (RA) densometer is used to obtain a continuous recording of density and can be very accurate if the slurry is under at least 200-psi pressure at time of measurement. Without pressure, the RA device will measure density incorrectly if entrained air is in the slurry and has not been collapsed. This dictates that the RA densometer is installed in the discharge line to the wellhead where pressure is usually available. The standard mud balance can be very inaccurate due to the influence of unpressurized, entrained air and is not generally recommended for slurry density measurements.

Water Tanks. Usually, portable tanks are used to hold mix water for the cement and for displacement. The total volume should be equal to the required operation plus excess for washing up equipment after the job. On some jobs the required volume of mix water exceeds storage capacity. In this event, ready access to the tanks must be provided for water trucks to replenish the supply as it is used. This requires careful planning to prevent running out of water before the job is completed. Always check the water to ensure that it is free from contaminants.

2.12 Job Monitoring

Locations To Monitor. Proper job execution includes monitoring and controlling several factors, particularly on critical jobs. Certain data must be collected and analyzed to ensure that timely decisions affecting the overall operation can be made. Recorded data should include pump rate in, annulus rate out, wellhead pressure (at the cementing head), density of fluids pumped in and those returning (using radioactivity devices or equivalent), cumulative displacement volume, cumulative return volume, and hook load during pipe reciprocation.^{23,24} To enable the job supervisor to make timely decisions, he should have a central monitoring point such as a monitoring van or portable electronic data recorder from which he can observe the entire operation.

Proper monitoring allows real-time diagnosis of problems during the cementing operation.^{23,24} Some events that can occur and cause a departure from job predictions of pressure and return rates include cement channeling, lost circulation, a restriction in the annulus, and a restriction in the casing. Early detection and correction of these problems may prevent a costly cementing failure. Proper monitoring techniques also allow evaluation of cementing procedures to achieve desired results.

Monitoring Mud Return Rate. In view of the phenomenon of free fall, a means of determining the down-hole performance of a cement job is needed (during free fall, the surface pump pressure is essentially zero). One way to do this is to measure the mud return rate and compare it with the predicted free fall rate. Figure 2.22 shows the mud return rate during an actual primary cementing job versus the surface pump rate. Note that the return rate is much different from the surface pump rate during most of the job. Of particular importance is the lower return rate during the latter part of free fall. With-

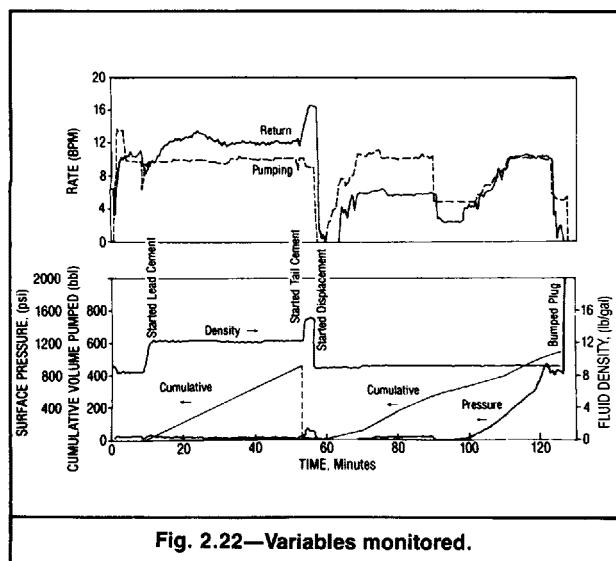


Fig. 2.22—Variables monitored.

out the knowledge that this lower return rate is normal, based on free-fall predictions, an erroneous conclusion might be made that lost circulation is occurring. Lowering the surface pumping rate on the basis of this erroneous conclusion could contribute to an unsuccessful cementing operation. It is pointed out again that of significant importance is the change in displacement flow rate that occurs in the latter part of free fall.²⁵ If turbulent flow displacement is desired, the surface pumping rate must be high enough to prevent the free-fall rate in the annulus from becoming lower than this minimum critical flow rate.

Flow Meters. There are various meters available for measuring the flow rate into and out of the well; the most accurate is the full-opening magnetic flowmeter. These meters are available in low pressure for the return line and high pressure for the injection line. They are applicable only for water-base fluids. For oil-base muds and other nonconductive fluids, turbine meters and wedge meters have been used successfully.

2.13 Quality Control

To ensure that each phase of the cementing operation is properly carried out, the many details must be checked. Key words in quality control are "never assume, always check; never estimate, always calculate."

Once cement slurry design and the entire operation have been engineered to a set of specifications, followup must be made to ensure a successful operation. Applying quality control from the beginning of design and continuing throughout job execution will eliminate many potential errors or mistakes that can cause a cementing failure. A comprehensive checklist for quality control has been published.²⁶

References

- Smith, D.K.: "Cementing," Monograph Series, SPE, Dallas (1976).
- Suman, G.O., Jr., and Ellis, R.C.: "Cementing Handbook," *World Oil* (1977).
- "Specifications for Materials and Testing for Well Cements," *API Spec. 10*, 4th Ed., API Publications and Distribution Section, Washington, DC (Aug. 1, 1988).
- Smith, R.C.: "Successful Primary Cementing Can be a Reality," *JPT* (Nov. 1984), 1851-1858.
- Shryock, S.H. and Smith, D.K.: "Geothermal Cementing - The State-of-the-Art," *Halliburton Services Brochure C-1274*.
- Matthews, W.R. and Kelly, J.: "How to Predict Formation Fracture Pressure and Fracture Gradient," *Oil and Gas J.* (Feb. 20, 1967), 92.
- Pilkington, P.E.: "Fracture Gradient Estimates in Tertiary Basins," *Pet. Eng. Intl.* (May 1978).
- Matthews, J.C. and Matthews, W.R.: "Program Calculates Frac Gradients for Many Basins," *Oil and Gas J.* (July 8, 1985) 39-43.
- Eaton, B.A.: "Fracture Gradient Prediction and Its Application in Oilfield Operations," *JPT* (Oct. 1969), 1353.
- Hottman, C.E. and Johnson, R.K.: "Estimation of Formation Fracture Pressures from Log-Derived Shale Properties," *JPT* (June 1965), 717.
- Christman, S.A.: "Offshore Fracture Gradients," *JPT* (Aug. 1973).
- Smith, R.C., Powers, C.A. and Dobkins, T.A.: "A New Ultra-lightweight Cement with Super Strength," *JPT*, Aug. 1980.
- Venditto, J.J. and George, C.R.: "Better Wellbore Temperature Data Equal Better Cement Job," *World Oil* (Feb. 1984).
- "How to Determine BHST from Well Log Data," *World Oil*, January 1977.
- Hartog, J.J., Davies, D.R., and Stewart, R.B.: "An Integrated Approach for Successful Primary Cementing," *JPT*, Sept. 1983.
- McElfresh, P.M.: "Chemical Thickening-Time Test for Cements," *JPT* (Feb. 1983).
- Smith, D.K.: "Silica Flour-Mechanism for Improving Cementing Composition for High Temperature Well Conditions," *Pet. Eng. Intl.* (Dec. 1980).
- Eilers, L.H. and Root, R.L.: "Long-Term Effects of High Temperature on Strength Retrogression of Cements," paper SPE 5028 presented at 49th Annual Fall Technical Conference, Houston, Oct. 6-9, 1974.
- Shell, F.J. and Wynne, R.A.: "Application of Low-Water Loss Cement Slurries," Paper No. 875-12-1 presented at API Rocky Mountain District Div. of Production Spring Meeting, Denver, April 1958.
- Beach, H.J., O'Brien, T.B., and Goins, W.C., Jr.: "Formation Cement Squeezes by Using Low-Water Loss Cements," *Oil and Gas J.* (May 29 and June 12, 1961).
- Pace, R.S., McElfresh, P.M., Cobb, J.A., Smith, C.L., and Olsberg, M.A.: "Improved Bulk Blending Techniques for Accurate and Uniform Cement Blends," paper SPE 13041 presented at the SPE 59th Annual Technical Conference and Exhibition, Houston, Sept. 16-19, 1984.
- Gerke, R.R., Simon, J.M., Logan, J.L., and Sabins, F.L.: "A Study of Bulk Cement Handling and Testing Procedures," paper SPE 14196 presented at the 60th Annual SPE Fall Meeting, Las Vegas, Sept. 22-25, 1985.
- Smith, R.C.: "Improved Cementing Success Through Real-Time Job Monitoring," *JPT*, June 1986.
- Arnold, E.S.: "Cementing: Bridging the Gap from Laboratory Results to Field Operations," *JPT*, Dec. 1982.
- Beirute, R.M.: "The Phenomenon of Free Fall During Primary Cementing," paper SPE 13045 presented at the 59th Annual Fall Technical Conference, Houston, Texas, Sept. 16-19, 1984.
- Smith, R.C.: "Use this checklist to improve primary cementing operations," *World Oil*, March 1986.

Chapter 3

Casing Equipment

author
Bob Sullaway

INDEX

SUBJECT	PAGE
3.1 Primary Cementing Equipment	34
3.2 Guide Shoe and Float Shoe	34
3.3 Float Collars	36
3.4 Float Equipment Performance	37
3.5 Multiple-Stage Cementing Collars	38
3.6 Slurry Compositions	39
3.7 Centralizers and Scratchers	39
3.8 Details of Multistage Cementing Operations	40
Free-Fall Cementing	40
Two-Stage, Free-Fall Plug Method	40
Two-Stage, Displacement Method	41
3.9 Three-Stage Cementing	43
3.10 Free-Fall Method Hydraulic Modification	43
3.11 Workstring-Operated Multistage Cementer	44
3.12 Cementing Plugs	45
3.13 Casing Attachments	47
Centralizers	47
Scratchers	48
3.14 Innerstring Cementing Method	49
Sealing Adapter and Floating Equipment with Sealing Sleeve ..	50
Baffle Collar with Latch-Down Plug and Sealing Sleeve	50
3.15 Summary	51

Chapter 3

Casing Equipment

By: Bob Sullaway

Bob Sullaway is a section supervisor in the Halliburton Services Tools Research and Engineering (TRE) department in Duncan, OK. Sullaway graduated from the University of Oklahoma in 1963 with a BS degree in petroleum engineering and worked as a reservoir and production engineer before joining Halliburton in 1969. Since that time, he has worked in the TRE department, specializing in design of down-hole tools used in cementing.

3.1 Primary Cementing Equipment

Numerous casing attachments have been developed for use in primary cementing operations to aid the operator in successfully placing the casing string in the wellbore and to enhance mud removal from the wellbore. The type of primary cementing equipment used depends on individual well requirements and may vary widely with geographical areas and from field to field. This chapter describes the basic types of cementing equipment available to perform all phases of primary cementing operation. General descriptions and uses of the types of equipment are discussed; applications for specialized variations of the equipment have been avoided.

3.2 Guide Shoe and Float Shoe

Four styles of guide and float shoes available are the guide shoe, float shoe, automatic-fill float shoe, and differential-fill float shoe. This equipment is available in a variety of steel grades and threads, with the simplest being the plain-end guide shoe (Fig. 3.1).

The rounded nose of the guide shoe directs the well casing away from ledges to minimize sidewall cave-in and helps the casing move safely past hard shoulders and through crooked holes. This guide shoe is typically run in combination with a float collar set one to three joints above the shoe. Spacing between the guide or float shoe and the float collar provides a chamber to contain mud-contaminated cement after cementing has been completed. This practice helps assure placement of good quality cement outside the bottom few joints of intermediate casing strings to help prevent backoff of bottom joints during drillout of floating equipment. These shoes are also used to cement surface casing and production strings.

Guide shoes, float collars, and the bottom two or three casing joints are typically made up in the casing string with a thread-locking compound to further help prevent backing off the bottom joints of surface and intermediate casing during drillout.

Figure 3.2 illustrates a side-discharge guide shoe which allows discharge of fluids through the steel case or concrete nose. Up to 60% of the fluid pumped travels through the side ports. This guide shoe is useful in several cementing practices.

1. Jetting off and washing down mud cake and cuttings from the bottom of the hole while rotating and/or reciprocating the casing.
2. Penetrating bridges when running casing.
3. Agitating and distributing cement to minimize channeling around the shoe to provide a better anchor for the shoe joint.
4. Jetting washed-out, over-sized sections of the wellbore.
5. Assuring circulation even if the casing is resting on the bottom of the hole or the bottom outlet is plugged with cuttings.

Float shoes guide the casing string as it is lowered into the hole and also provide an integral backpressure valve. Float shoes may be used in conjunction with float collars (located one to three joints above) on deep or intermediate casing strings where an additional safety factor of two float valves is desirable.

Strain on the derrick caused by casing weight can be minimized by using a float shoe to essentially float the well casing to the bottom of the hole. Casing flotation is accomplished when drilling fluid is not allowed to flow upward through the float valve inside the casing. The amount of suspension is controlled by the amount of fluid placed on the inside of the casing by a fluid fill line from the surface.

When casing is safely landed on bottom, circulation is established through the casing and float valve and up the outside of the casing string. After the cement job is completed, the backpressure valve functions to keep the cement below and behind the casing. Density of the cement used in cementing oil and gas wells is commonly greater than the density of the displacing fluid used to pump the cement to a shutoff. The difference in these densities creates a differential pressure across the float

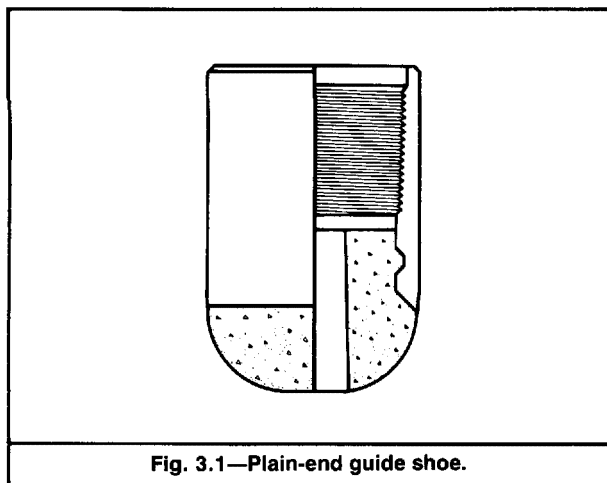


Fig. 3.1—Plain-end guide shoe.

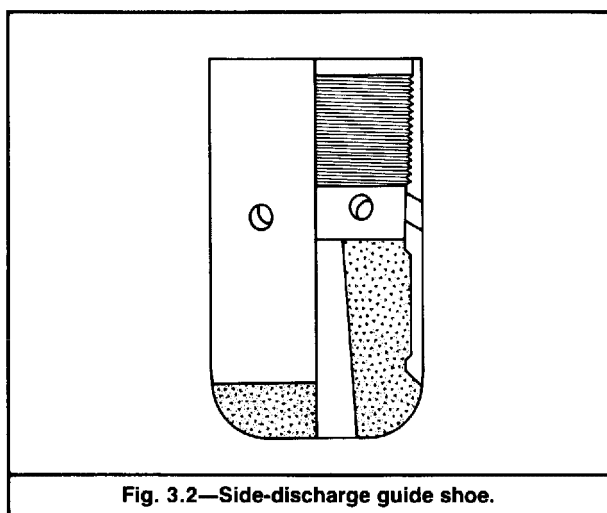


Fig. 3.2—Side-discharge guide shoe.

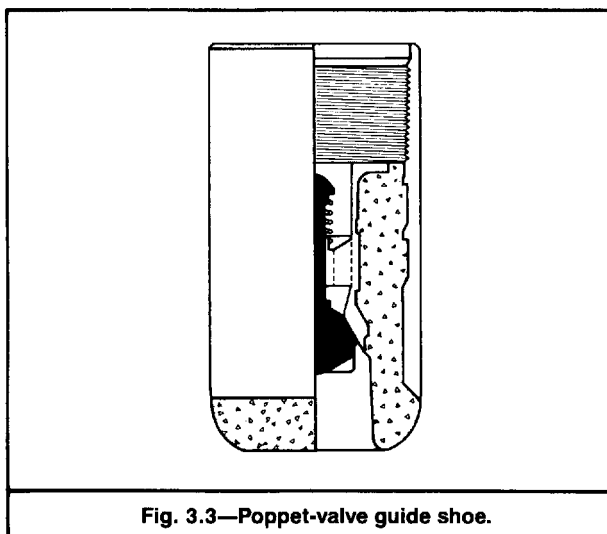


Fig. 3.3—Poppet-valve guide shoe.

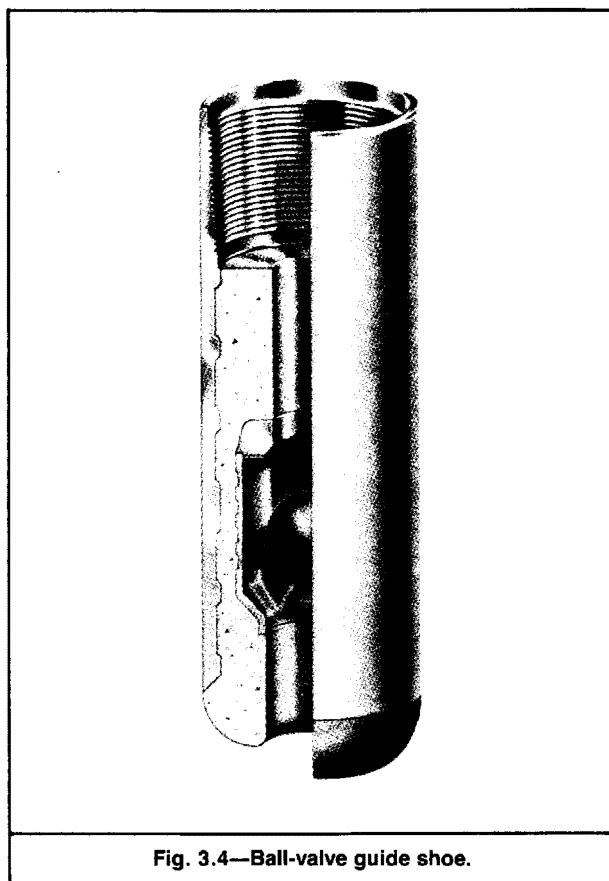


Fig. 3.4—Ball-valve guide shoe.

valve to aid in keeping the valve closed until the cement sets. The float valve must have sufficient strength to withstand this differential pressure.

The external case of a guide shoe or float shoe is an integral part of the casing string and is usually made of the same material grade as the casing. Most manufacturers provide equipment compatible with casing grades through API N-80. Higher-strength float equipment is usually available on special order. The ID of the external case is larger than the drift diameter of the lightest weight of the casing range for a given casing size. Internal components of the float shoe or guide shoe are usually made of drillable materials such as brass, aluminum, plastic, and concrete. Use of cast or ductile iron is undesirable because of increased use of polycrystalline diamond compact (PDC) bits.

Three types of valves are found in float shoes: poppet, ball, and flapper (Figs. 3.3 to 3.5). Poppet and flapper valves are usually spring-activated, providing immediate closure of the valve. The ball-valve type depends on some backflow of fluid to raise the ball to its shutoff seat.

Another variation of the float shoe is the automatic, or differential-fill type. Automatically filling the casing as it is being run into the well saves costly rig time over manually filling, minimizes casing sticking, and saves up to one-third running-in time by eliminating frequent stops for top-filling pipe. Automatic filling of the casing is usually controlled by a spring-loaded backpressure valve held in the open position with a plastic orifice tube (Fig. 3.6) or restricted opening (Fig. 3.7) in the float shoe or collar. Fluid is allowed to enter the bottom of the float

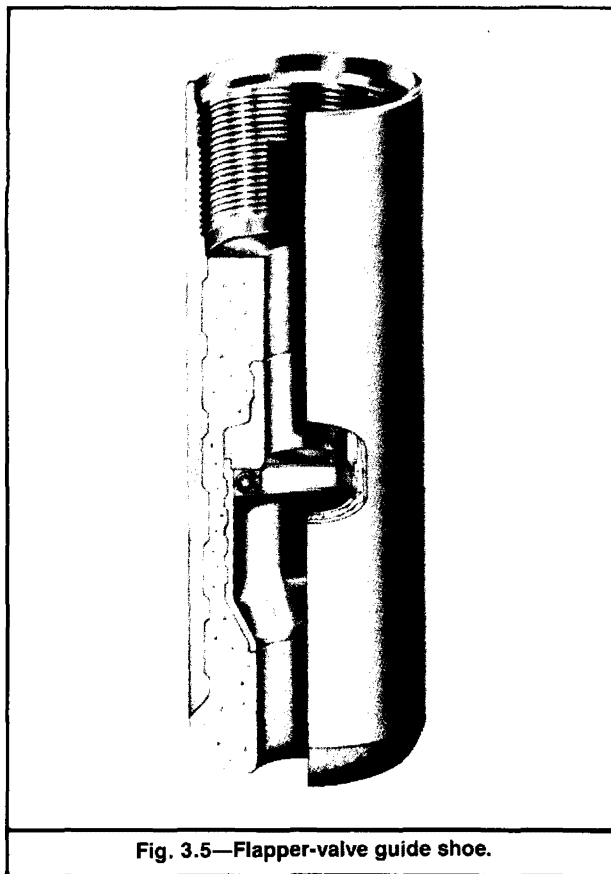


Fig. 3.5—Flapper-valve guide shoe.

shoe while the casing is being run, thereby reducing running time and surge pressures or "ram effect" on the formation. To disengage the automatic-fill device, a weighted ball is usually pumped down the casing and through the orifice or restricted opening.

The differential-fill float shoe shown in Fig. 3.8 allows fluid entry into the casing, filling through the bottom to maintain a controlled differential pressure between the inside and outside of the casing. The speed at which the casing is being run into the well does not affect the operation of the fill valve. Strength of the spring on the fill valve determines the rate of fill. The float mechanism of differential-fill equipment is activated by a ball dropped or pumped through the casing. Disengaging the automatic-fill feature on the orifice or restricted valve-type float shoe is usually accomplished by pumping through the valve at higher-than-normal circulation rates. A pump rate of 3 to 6 bbl/min deactivates the automatic-fill feature, converting the equipment to a standard float shoe.

3.3 Float Collars

The float collar (Figs. 3.9 to 3.11) is an essential tool used in cementing the casing string. Float collars are normally run one or more joints above the guide or float shoe and contain backpressure valves similar to those found in float shoes. On long or deep intermediate strings of casing, where the differential pressures across the valve are quite large, more float collars may be used as an added safety factor.

The main purposes of the float collar are to provide a

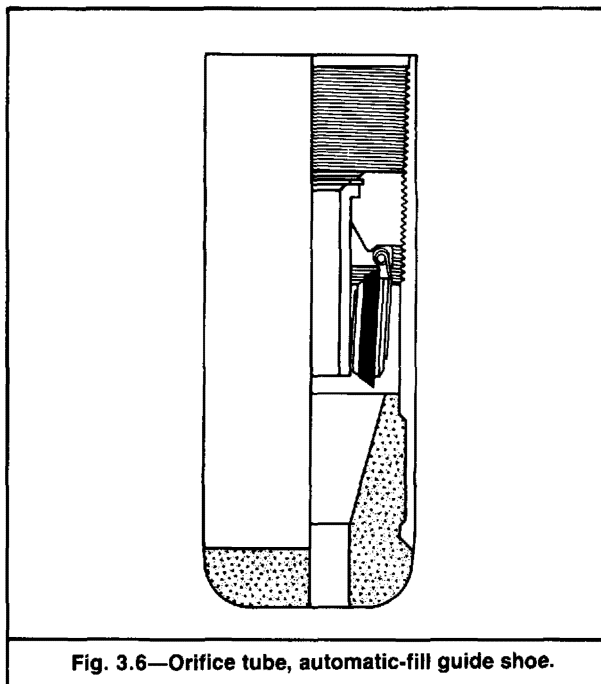


Fig. 3.6—Orifice tube, automatic-fill guide shoe.

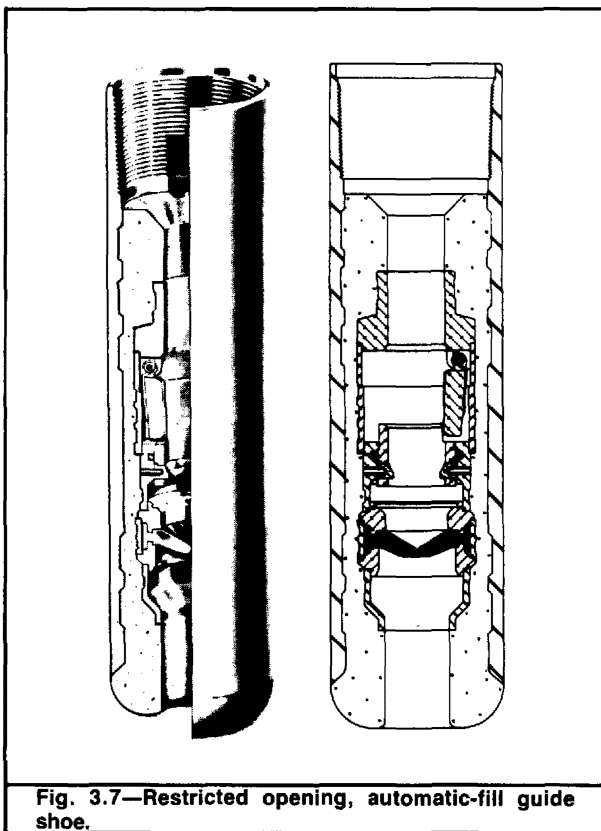
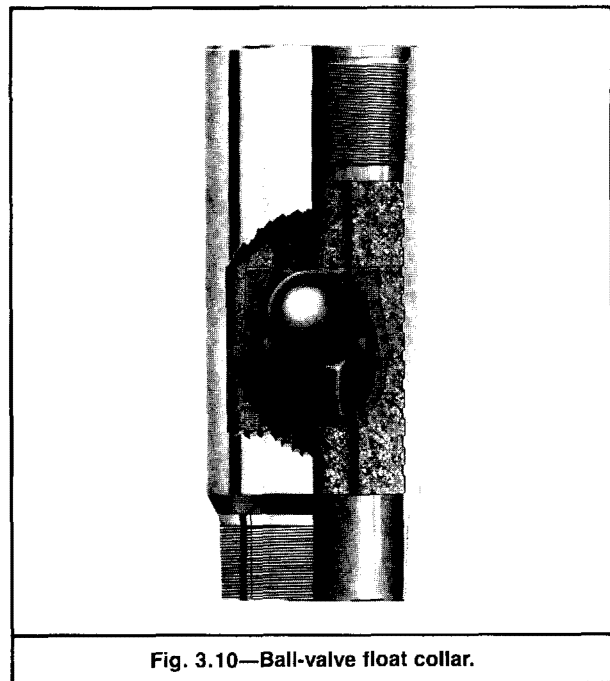
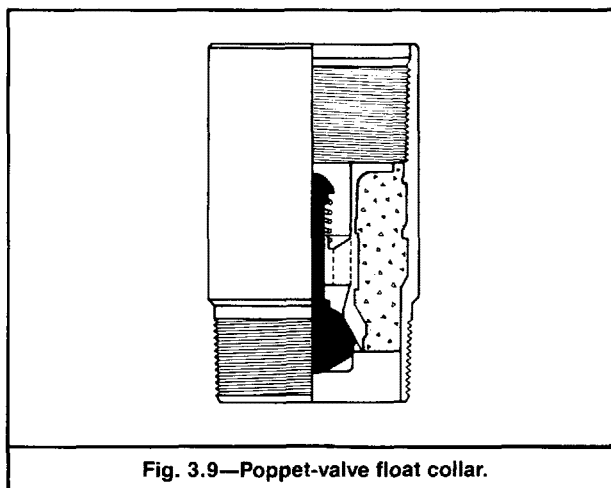
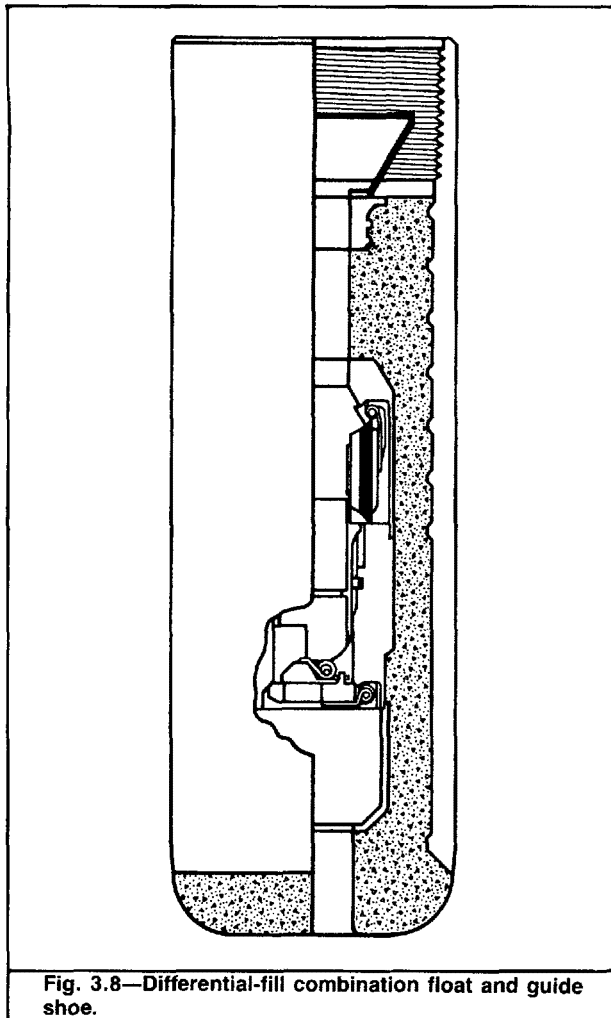


Fig. 3.7—Restricted opening, automatic-fill guide shoe.



check valve to prevent cement from reentering the casing ID and to act as a seat for cementing plugs to indicate when cement placement is complete. When used in conjunction with cement plugs, the float collar also controls the amount of cement left in the casing. For use with a guide shoe or automatic- or differential-fill float shoe, float collars may be obtained with either differential- or automatic-fill features. The equipment is made up in the casing string by casing threads, weldments, or both. As a standard, float collars are available with box-up, pin-down thread connections; box thread connections are available on special order. Standard float collars are made of drillable materials such as brass, plastic, and concrete to facilitate easy drillout with standard three-cone rock bits or PDC bits.

The external case of a float collar is an integral part of the casing string and is usually made of the same material grade as the casing. Most manufacturers provide equipment compatible with casing grades through API N-80. Higher-strength float collars are usually available on special order. Most 8-Rd and buttress-thread float collars made in the United States are machined per API Spec 5B; many international manufacturers do not follow the API specification.¹ The operator should state the thread specification desired when ordering this type of equipment.

3.4 Float Equipment Performance

A task group of the American Petroleum Institute (API) has formulated a recommended practice (RP) for performance testing of cementing float equipment.² The purpose of RP 10F, prepared under the jurisdiction of the API Committee on Standardization of Well Cements (Committee 10), is to provide (1) performance-testing criteria to the industry, and (2) a means of comparing various equipment on the market for operators and users of the equipment.

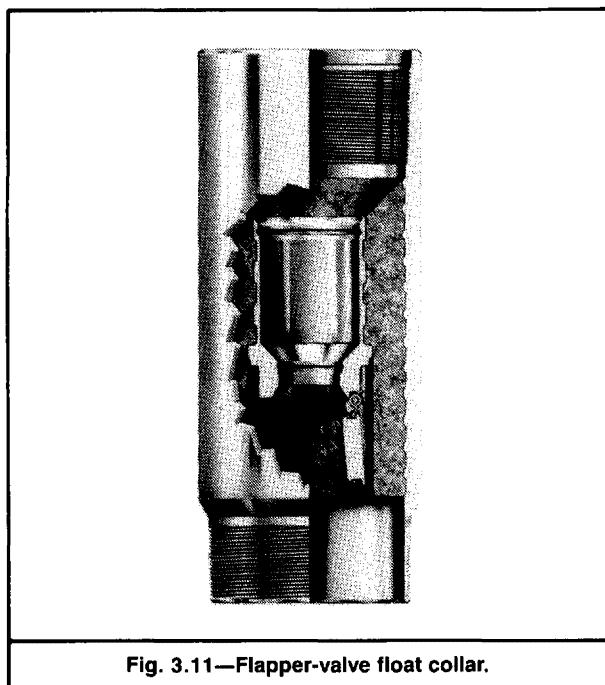


Fig. 3.11—Flapper-valve float collar.

Although there are many criteria to be examined in determining performance of float equipment, the RP is limited to consideration of the criteria listed below.

1. Durability under down-hole conditions. As normally used, cementing float equipment must function after a fluid, sometimes containing abrasive solids, has been circulated through the equipment for a period of time. The equipment must function in various orientations while exposed to elevated temperatures and pressures.

2. Differential pressure capability from below. Because the hydrostatic pressure of the fluid occupying the annulus immediately after the cement has been placed is usually greater than the hydrostatic pressure of the corresponding column of the fluid inside the casing, under normal operations float equipment must be capable of withstanding a differential pressure in which the higher pressure being exerted is from below the check valve mechanism. The capability of float equipment to withstand differential pressure from below is also important in certain well control situations. If the hydrostatic pressure of the fluid inside the casing becomes less than the pressure of formation fluids in formations near the bottom of the casing, the well may try to flow up the casing. In such a situation, the float equipment becomes a primary well-control device.

To facilitate communication between users and suppliers of cement float equipment, three service categories of flow-durability testing and three service categories of static high-temperature/high-pressure testing are described in the RP document. Categories for flow durability are shown in Table 3.1.

Categories for flow durability for casing-fill float equipment are shown in Table 3.2. The three service categories of temperature/pressure tests are shown in Table 3.3.

The proposed RP on competitive testing of float equipment also stipulates the mud properties and temperatures

TABLE 3.1—CATEGORIES FOR FLOW DURABILITY²

Category*	Duration (hours)	Maximum Pressure** (psi)
I	8	1500
II	12	3000
III	24	5000

*Circulation rate is 10 bbl/min for float equipment larger than 3 1/2 in. and 6 bbl/min for 3 1/2 in. and smaller float equipment.
 **The maximum test pressure should be the lesser of the valve shown or 80% of the manufacturer's rated burst or collapse pressure for the float equipment casing, whichever is applicable.

TABLE 3.2—CATEGORIES OF FLOW DURABILITY TESTS FOR CASING FILL EQUIPMENT²

Category	Duration (hours)		Maximum Pressure*** (psi)
	Reverse*	Forward**	
I	2	8	1500
II	4	12	3000
III	6	24	5000

*Circulation rate for all categories is 3 bbl/min.
 **Circulation rate is for float equipment larger than 3 1/2 in. and 6 bbl/min for 3 1/2 in. and smaller equipment.
 ***The maximum test pressure should be the lesser of the valve shown or 80% of the manufacturer's rated burst or collapse pressure for the float equipment casing, whichever is applicable.

TABLE 3.3—CATEGORIES OF STATIC HIGH TEMPERATURE/HIGH PRESSURE TESTS²

Category*	Temperature (°F)	Maximum Pressure** (psi)
A	200	1500
B	300	3000
C	400	5000

*Duration at temperature is 8 hours for all categories.
 **The maximum test pressure should be the lesser of the valve shown or 80% of the manufacturer's rated burst or collapse pressure for the float equipment casing, whichever is applicable.

under which the flow durability tests are to be conducted. The document provides suggested means of backpressure testing during the tests and a suggested flow loop setup for testing.

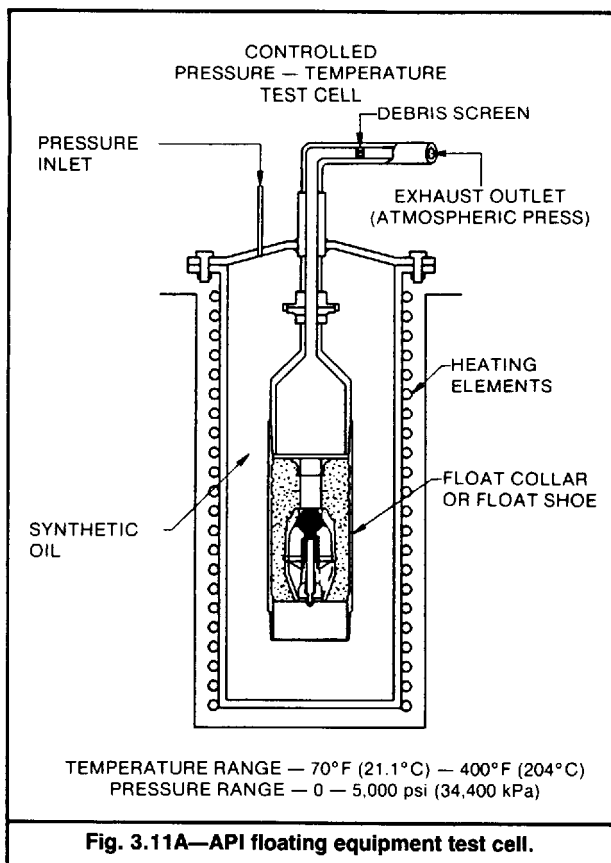
The RP further provides a test chamber schematic of one means recommended for conducting high temperature/pressure tests (Fig. 3.11A).

3.5 Multiple-Stage Cementing Collars

Multiple-stage cementing tools are used under certain conditions for cementing two or more separate sections of the wellbore behind the same casing string or to cement a long section in two or more stages of cement. The multiple-stage cementer tool allows the operator to choose what sections of the wellbore will be cemented.

1. Full-depth cementing in deep holes at pressure (both pump and hydrostatic) below formation breakdown and casing collapse pressures.

2. Less than full-depth cementing in deep holes where it is permissible.



3. Cementing off formations at any point.
4. Reducing channeling.
5. Completing dual-zone wells.
6. Minimizing loss of cementing slurry to thief zones.

The multiple-stage cementer will allow the use of different blends of cement at different levels in a well, e.g., in Arctic regions where nonfreezing fluid is required across the permafrost zone.

Three basic types of multiple-stage cementing tools in common use today are (1) the plug-operated (Fig. 3.12), (2) the pressure-operated (Fig. 3.13), and (3) the drillpipe-operated (Fig. 3.14). In addition to these tools, multiple-stage cementing may be completed by perforating various sections of the well casing and pumping cement during initial cementing operations on the well. The latter method has been outdated by the development of drillpipe-operated multiple-stage cementing tools and has not been commonly performed in recent years.

Multiple-stage cementing consists of conventional placement of cement slurry around the lower portion of the casing string, followed by placement of successive upper stages through ports in a multiple-stage cementing tool, after the lower section has been cemented. Most multiple-stage cementing is done in two or three stages, but there is no limit to the number of stages of cement which can be performed using the drillpipe-operated stage collars on the market today.

Although numerous stages of cement may be placed in the wellbore with currently available tools, the primary use of multiple-stage cementing tools is to reduce or eliminate the possibility of lost circulation as a result of excessive hydrostatic pressures from a high column of cement.

Equipment and material requirements for stage cementing are not significantly different from those of a conventional cementing operation. The primary difference is the equipment needed to operate multiple-stage cementing tools, i.e., a different cementing head for two- or three-stage tool operations and the plugs required for tool operations. The plugs for the first stage of cement operations are designed to pass freely through the stage cementers, and in some operations, special baffles or float equipment must be used. This special equipment will be discussed in more detail later in this chapter.

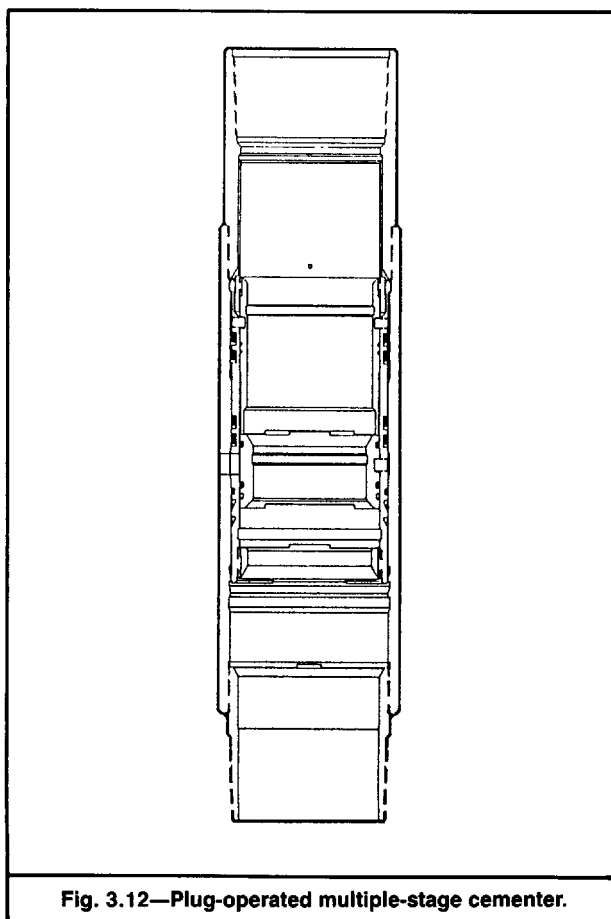
3.6 Slurry Compositions

In some areas, lost circulation materials are used in cementing both the lower and upper stages. The amount of lost circulation material in cement slurries should be reviewed based on individual areas. Operations using lost circulation materials indicate that the maximum dimension of any such material should be less than half the diameter of the multiple-stage cement ports.

Other common additives for reducing slurry density, avoiding lost circulation, and economically increasing slurry volume, such as bentonite, perlites, pozzolans, and diatomaceous earth, are frequently used in multiple-stage cementing. Chemical washes commonly used during the lower stage are also frequently used in the upper stages.

3.7 Centralizers and Scratchers

Centralizers may be used in conjunction with the upper and lower stages. Scratchers are sometimes used in both stages. Multiple-stage swivels allow the use of centralizers and scratchers during the second stage even though the lower



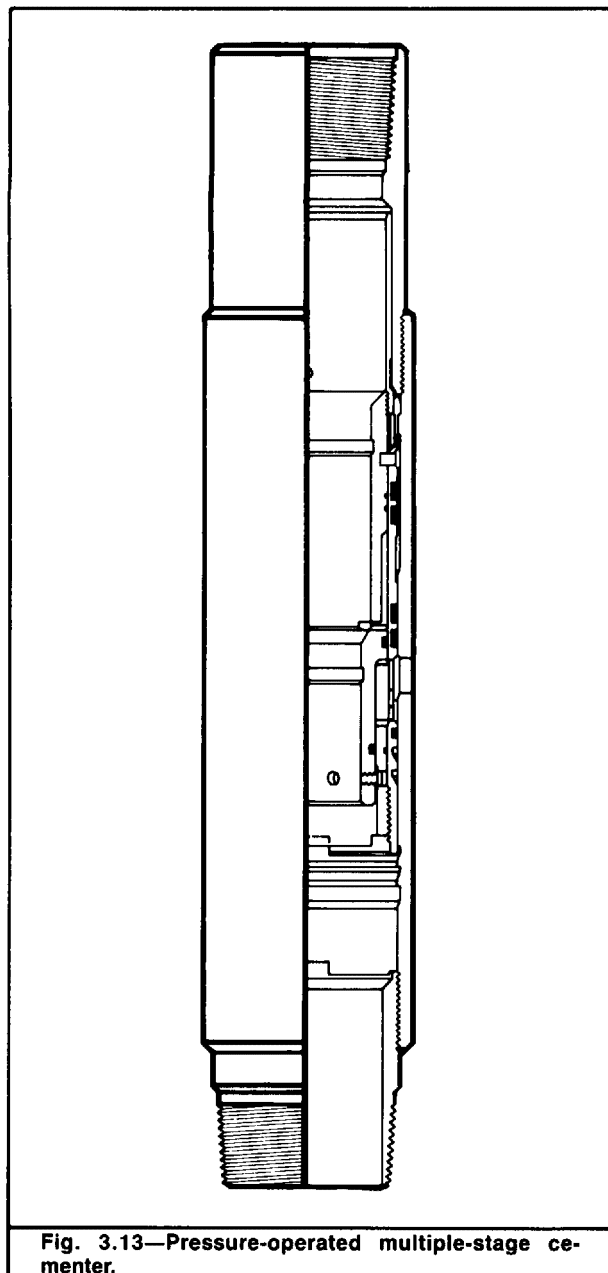


Fig. 3.13—Pressure-operated multiple-stage cementer.

or bottom stage is often set before the upper stage is displaced. Centralizers are sometimes used immediately above and below the stage tool to prevent distortion of the tool due to hole conditions. Generally, both scratchers and centralizers are used with the same regularity in single-stage and multistage cementing.

3.8 Details of Multistage Cementing Operations

Free-Fall Cementing. In cementing operations where first-stage cement is not required to fill the annulus from the bottom of the casing all the way to the cementer, the free-fall plug set may be used. The free-fall method is the most common method of multiple-stage cementing used and is usually preferred because it provides a positive shutoff following the first stage, which prevents overdisplacement of cement around the shoe joint. The cementer is usually located relatively far away from the

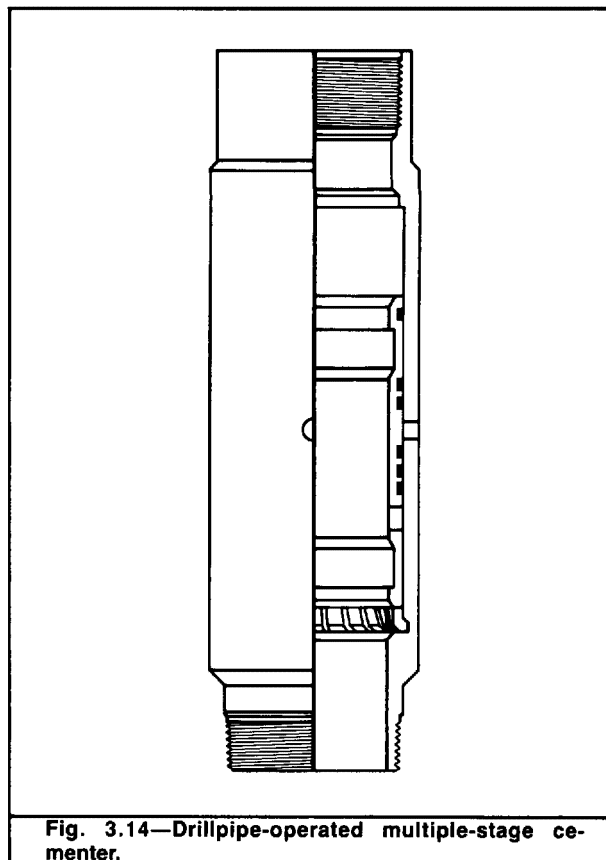


Fig. 3.14—Drillpipe-operated multiple-stage cementer.

bottom and may be left closed after cementing the first stage, or it may be opened to allow displacing fluid to be pumped to establish and maintain circulation while waiting for the first-stage cement to set.

When using the free-fall (or "bomb") type cementing method, a free-fall plug set must be used. Figure 3.12 illustrates one type of stage cementing collar used with the free-fall plug set. Figure 3.15 illustrates plugs used in this method.

Two-Stage, Free-Fall Plug Method. Components of the free-fall plug set are described below.

1. The shutoff baffle is made of drillable material for quick and complete removal when the casing is drilled out after cementing. Usually, the baffle is placed either in the uppermost float collar or in a casing coupling one or more joints above the bottom end of the casing. Some cement will be left inside the casing at the end of the first stage. It is preferable to drill out some first-stage cement rather than risk overdisplacement of the first stage. Cement around the shoe joint helps to prevent unscrewing the lower joints during drillout. Also, if this is a critical point in the well, a squeeze job might otherwise be necessary to place cement behind the casing.

2. Following the first stage of cement is the shutoff plug. Its flexible wipers permit it to pass freely through the seats inside the cementer. The shutoff plug separates the slurry from the displacement fluid and stops circulation when pumped to shutoff against the shutoff baffle, thereby preventing overdisplacement of the first stage of cement.

3. When first-stage cement has been displaced, the



Closing Plug



Free-Fall Plug



Shut-Off Plug



Shut-Off Baffle

Fig. 3.15—Free-fall, two-stage plug set.

free-fall opening plug is dropped into the casing and is allowed to fall by its own weight to the opening seat in the multiple-stage cementer. The time required for the free-fall plug to reach the cementer must be estimated since there is no surface indication when this occurs. Time is determined by the viscosity and density of the fluid in the casing as well as the degree of hole deviation, but is normally in the range of 200 ft/min. When the estimated falling time for the free-fall plug has elapsed, pressure is applied to the casing, compressing the fluid below the cementer, shearing opening sleeve pins, and opening the cementer.

Surface indications of cementer opening are a rapid decrease in pressure and the start of fluid circulation. If this does not occur, (1) the free-fall opening plug may not have reached its seat and more time should be allowed, or (2) debris on the opening seat is preventing the free-fall opening plug from sealing. After each pressure buildup, a rapid pressure release will flush debris off the seat, and a seal can be obtained.

After the cementer is opened, displacing fluid should be pumped to maintain circulation while waiting for the first stage to harden. Circulation is usually maintained at a lower pressure than before the cementer was opened.

The desired amount of cement for the second stage is pumped through the cementer ports, followed by a closing plug. This plug is similar to the five-wiper cementing plug but has a hard nose on its lower end. Its function, in conjunction with applied pressure, is to shear the releasing sleeve pins and close the ports.

A sudden increase in casing pressure and stopping of circulation indicate the cementer is closed. An operating schematic of cementing using a free-fall plug set for two-stage cementing is shown in Fig. 3.16.

This procedure permits a check on the displacement of the lower stage, as well as circulation through the stage collar for as long as is desired, and minimizes the amount of cement in the casing at a given time. However, it precludes use of a plug ahead of the slurry for the second stage, and some contamination of the slurry may be expected. Consideration of displacement control is probably the greatest single factor in the decision to use the free-fall (or "bomb") plug wherever possible.

When using a free-fall plug, an optional first-stage bottom plug set (Fig. 3.17) consisting of a bypass baffle and bypass plug may be used if desired. If a bypass baffle is used, it is placed on top of the float collar. If a bypass plug is used, it is placed in the casing immediately ahead of the first stage of cement and acts as a bottom plug for first-stage cement. The bypass plug passes through the cementer and shutoff baffle and stops on the bypass baffle. First-stage cement is then pumped freely past the plug, through the holes in the bypass baffle, through the float collar and shoe, and into the annulus.

Two-Stage Displacement Method. When cement is to be placed in the entire annulus from the bottom upward to, or above, the cementer, a displacement plug set should be used. Greater depths or highly deviated holes (exceeding 30°), which might retard the falling rate of the free-fall plug, may also require the use of the displacement plug set. When the multiple-stage cementer is placed closer than 500 ft from the float collar, the displacement plug set should be used because fluid com-

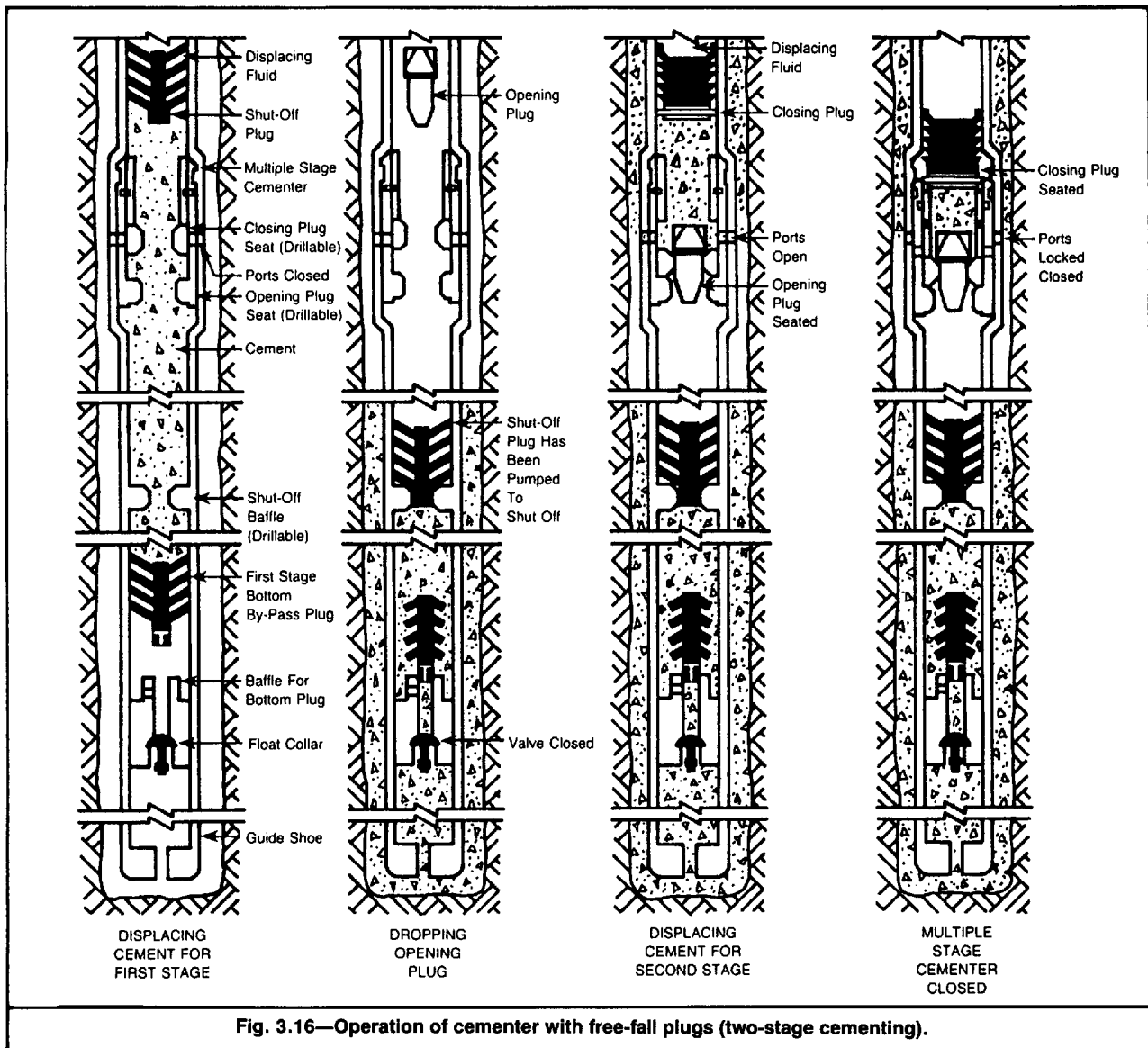


Fig. 3.16—Operation of cementer with free-fall plugs (two-stage cementing).

pression below the cementer is required to open the cementer with the free-fall plug set. The displacement method may be employed as a continuous operation with no interruptions of pumping until all cementing stages have been completed. Fluid volumes must be accurately calculated and carefully measured to prevent overdisplacement or underdisplacement of any of the stages, especially the first stage.

When cementing using the displacement method, a displacement-type plug set with appropriate casing hardware must be used. The equipment required is illustrated in Fig. 3.18.

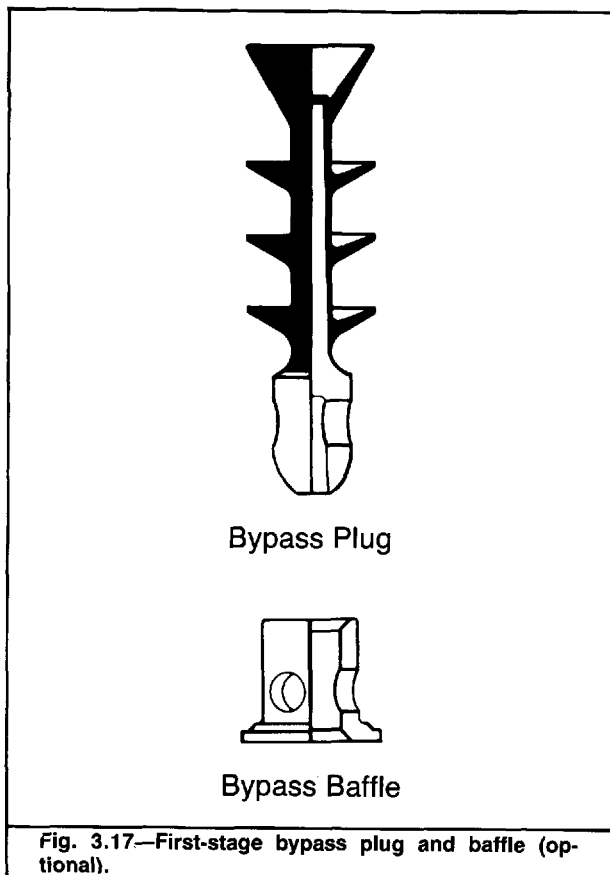
1. The bypass baffle has large fluid ports in its side and center for unobstructed flow. It is installed in the uppermost float collar as the casing is lowered into the well and is held in place by the casing joint above it. This baffle can not be installed in a casing coupling but must be supported by the strong, flat concrete base in the float collar. First-stage cement, followed by a bypass plug, is pumped out the bottom of the casing and into the annulus. The bypass plug has flexible wipers which allow it to pass freely through the seats inside the cementer, and

serve to separate the slurry from the displacement fluid.

2. The displacement-type opening plug consists of flexible rubber cups, centering fingers on each end, and a seat near its top end. After releasing the bypass plug, the calculated casing capacity between the bypass baffle and cementer is pumped and the opening plug released. The balance of the calculated displacement fluid volume is then pumped to seat the opening plug in the opening sleeve of the cementer. Pressure is then applied as required to open the tool. Since it is usually preferable to drill out cement inside the casing rather than to risk overdisplacement of the first stage, it might be preferable to cut the spacer fluid volume between the bypass plug and displacement-type opening plug by one or two barrels to help prevent overdisplacement of the first stage.

Pressure applied to the opening plug opens the cementer ports. Displacing fluid may be pumped to maintain circulation while waiting for the first stage of cement to harden, or the second stage of cement may be pumped immediately.

The closing plug in a displacement plug set is the same as that used in the free-fall method and closes the ce-



menter in the same way.

If a plug is desired ahead of first-stage cement to separate it from the fluid in the casing, a first-stage bypass plug set may be used with either the free-fall or the displacement methods. This is an optional plug set (Fig. 3.19). A detailed operating schematic using a displacement method operation is illustrated in Fig. 3.20.

3.9 Three-Stage Cementing

Three-stage cementing is not often attempted. When required, the lower stage is displaced in the conventional manner, the second stage is displaced by the displacement method using displacement plugs, and the upper stage is controlled with free-fall plugs. The upper stage cementer must always be opened with a free-fall plug because the casing is closed to flow by the closing plug of the lower cementer. Special stage cementers are available which permit the use of free-fall plugs on both second- and third-stage collars. Smaller plugs, which will not actuate the upper stage cementer, are made to engage and actuate a modified collar for the second stage.

3.10 Free-Fall Method Hydraulic Modification

A hydraulically-operated multiple-stage cementer may be used with a free-fall plug set (Fig. 3.15). This cementer may be opened, if desired, with application of pressure to the casing and requires no free-fall plug. If desired, the cementer may also be opened by using a free-fall plug. The hydraulically-operated multiple-stage cementer has

