Well Cementing
Second Edition

Editors
Erik B. Nelson and Dominique Guillot
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Seventeen years ago, following the success of *Reservoir Stimulation* (edited by M.J. Economides and K.G. Nolte), Schlumberger decided to produce a companion work concerning well cementing technology. The result, *Well Cementing*, was published in 1990. The positive response from the industry has been very gratifying and humbling. In late 2002, Schlumberger decided to produce a second edition. It is our sincere hope that this updated textbook will be considered a worthy successor. During the past 3 years, we have become deeply indebted to many people and organizations without whose generous assistance this project could never have been completed.

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Finally, special thanks go to Gretchen Gillis, advisory editor of the Oilfield Review magazine. Gretchen read every word of the manuscript and made innumerable suggestions that greatly improved the clarity and flow of the chapters. Her participation in this project far exceeded the call of duty.
The first edition of *Well Cementing*, published in 1990, presented a comprehensive review of the scientific fundamentals, engineering considerations, and operational procedures associated with the processes collectively known as cementing. Such processes include primary cementing (casings and liners) and remedial cementing (plugs and squeezes).

Since 1990, the cementing industry has made significant progress in many areas, including

- new cement additives
- improved temperature modeling
- standardized testing procedures
- deepwater cementing
- enhanced cement-evaluation tools and procedures
- mechanical properties of set cement and long-term durability.

This second edition is an updated reference that reflects these advances. However, before discussing recent progress, let’s review some of the basic cementing objectives.

**P-1 Primary cementing**

Primary cementing is the process of placing cement in the annulus between the casing and the formations exposed to the wellbore. This subject is presented in Chapter 13. Since its inception in 1903, the major objective of primary cementing has always been to provide zonal isolation in oil, gas, and water wells, i.e., to exclude fluids such as water or gas in one zone from oil in another zone in the well. To achieve this objective, a hydraulic seal must be created between the casing and cement and between the cement and the formations, while at the same time preventing fluid channels in the cement sheath (Fig. P-1). This requirement makes primary cementing the most important operation performed on a well. Without complete isolation in the wellbore, the well may never reach its full producing potential.

The basic process for accomplishing a primary cementing job uses the two-plug method for pumping and displacement. This method was first used in 1910 in shallow wells in California. After the well reaches the desired depth, the drillpipe is removed, and a larger-diameter string of casing is run to the bottom of the well. At this time, the drilling mud is still in the wellbore. This mud must be removed and replaced with a cement slurry. The most common process to accomplish this is the two-plug cementing method (Fig. P-2). To prevent contamination with mud, two plugs isolate the cement as it is pumped down the casing. Sufficient cement slurry is pumped into the casing to fill the annular column from the bottom to at least the top of the pro-
ductive zones. Typically, cement slurry is brought to higher locations to exclude other undesirable fluids from the wellbore, to protect freshwater zones, and to protect the casing from corrosion. The cementing process is completed when a pressure increase at the surface indicates the top plug has reached the landing collar or float collar and displacement with mud or water is terminated. The well is shut in for a time to allow the cement to harden before completion work or drilling to a deeper horizon begins.

Although wells are drilled deeper today (30,000 ft [9,100 m] or more), technology has advanced, and cementing practices have changed, the basic two-plug method described above remains predominant.

**P-2 Remedial cementing**

Remedial cementing, presented in Chapter 14, consists of two broad categories: squeeze cementing and plug cementing. Squeeze cementing is the process of placing a cement slurry into the wellbore under sufficient hydraulic pressure to partially dehydrate or expel water from the cement slurry, leaving a competent cement that will harden and seal all voids (Fig. P-3). Plug cementing (Fig. P-4) is the placement of a limited volume of cement at a specified location inside the wellbore to create a solid seal or plug.

Remedial cementing operations are performed for various reasons: to repair faulty primary cementing jobs, alter formation characteristics, repair casing problems, and abandon wells. Both operations require as much technical, engineering, and operational experience as any primary cement job.
Since the early days, many advances have been made in all of the disciplines associated with cementing. Special Portland cements, manufactured expressly for use in well cementing, allow the industry to use cement systems that are tailored for the conditions encountered downhole. A wide variety of chemical additives makes it possible to place durable cement slurries in wellbore environments ranging from permafrost to geothermal reservoirs. To achieve optimal cement placement and zonal isolation, improved techniques have been developed to condition the wellbore before a primary cement job. Such techniques also reduce the need for remedial cementing. Equipment and techniques have been developed to properly monitor all cement-job parameters. This allows timely decisions during a job to increase the probability of success. Finally, many tools and techniques have been developed to evaluate the quality of the cement job, allowing the operator to make informed decisions regarding future operations. Since 1990, progress has been especially significant in the areas discussed below.
P-3.1 Cement additives
The cement service companies have introduced multi-purpose additives that simultaneously act as a retarder, fluid-loss additive, and dispersant. We have also seen the introduction of additives that are applicable to a much wider range of well conditions. Such additives reduce the number of cement additives required to perform a cement job. The reader will find a complete discussion of cement additives in Chapter 3.

For many years, the industry has used cement additives that reduce the cement-slurry density. Most of these additives absorb water, allowing the addition of water to the slurry without solids segregation. In most cases, as the slurry density decreases, the compressive strength of the set cement also decreases. Consequently, the lowest slurry density at which water-absorbing additives can be used is about 12 lbm/gal [1,440 kg/m³]. During the 1980s, hollow microspheres and foamed cements were developed to allow the preparation of competent cements at densities as low as 8 lbm/gal [960 kg/m³]. Foamed cements have become especially popular; however, their preparation requires special equipment at the wellsite. During the 1990s, the major cement service companies developed competent 8- to 12-lbm/gal cement systems that were not gas entrained.

At the other extreme, additives that increase the slurry density (weighting agents) have been improved. Traditionally, such additives have been dry-blended with the cement. For many years, the industry has wanted a weighting agent that could be added directly to the mix water. This approach would give the operator much more flexibility in controlling the slurry density during the job and reduce the need to prepare custom cement blends. During the past 10 years, this goal has been realized and such a material is being used both on land and offshore.

P-3.2 Temperature modeling
Well cementing requires an accurate knowledge of downhole temperatures for proper slurry design and placement. The bottomhole static temperature is a starting point for slurry design. Prejob tests, such as determining the thickening time, are based on the bottomhole static temperature. The thickening time test is performed at the bottomhole circulating temperature at a given casing point. The initial bottomhole circulating temperatures were developed from temperature gradients derived from geothermal maps and a very limited number of data points collected by an operator in the early 1950s. The initial American Petroleum Institute (API) temperature tables were based on a temperature gradient of 1.5°F/100 ft [0.8°C/30 m]. A series of data points was taken in the mid-1960s, and a set of API tables was introduced in the mid-1970s covering temperature gradients from 0.9° to 1.9°F/100 ft [0.5° to 1°C/30 m] over a range of depths.

Fig. P-5. Cement additives allow the use of Portland cement in a wide range of wellbore environments.
In addition to the temperature modeling programs, standard API/International Organization for Standardization (ISO) publications (for example, API RP 10B, Recommended Practice for Testing Well Cements, and ISO 10426-2, Petroleum and natural gas industries - Cements and materials for well cementing - Part 2: Testing of well cements) now include equations to calculate bottomhole circulating temperatures for casing-, liner-, squeeze-, and plug-cementing operations. Since then, operators and cement service companies have developed downhole tools to obtain more accurate temperature data. In the past 10 years, the major cement service companies have introduced temperature-modeling programs that more accurately predict downhole temperatures for cement-slurry design. The reader is referred to Chapter 12 and Appendix B for a complete discussion of this topic.

P-3.3 Standardization procedures

In the early 1980s, the petroleum industry embarked on a major effort to merge the API standard recommended practices with the ISO documents. It should be clarified that the ISO standards incorporate standards originating from various countries. Joint cooperation between operators, cementing service companies, and manufacturers has allowed the conversion of many of the current API documents pertaining to well cementing to active ISO documents. Two primary examples follow.

- API Specification 10B—Recommended Practice for Testing Well Cements—has been issued as ISO-10426-2, Petroleum and natural gas industries - Cements and materials for well cementing - Part 2: Testing of well cements.

The cementing industry continues to address cement and cement-testing standards. A full presentation of cement testing is given in Appendix B.
P-3.4 Deepwater drilling
The last 10 years have seen deepwater drilling increase considerably. The shallow-hole sections of the wellbore have required the development of special cement slurries and testing procedures to properly reflect the service conditions. The cement service industry responded very quickly to this need, and appropriate slurries have been developed. The testing procedures have been completed and published as ISO document 10426-3, *Petroleum and natural gas industries - Cements and materials for well cementing - Part 3: Testing of deepwater well cement formulations*.

**Fig. P-7.** Laboratory testing.

**Fig. P-8.** Major deepwater hydrocarbon provinces (red).
P-3.5 Cement sheath evaluation tools

Ultrasonic cement-sheath evaluation has continued to expand. Modern tools may be used in larger-diameter casing, oil-outside-phase drilling fluids, and high-density drilling fluids. Similar improvements have also been made with acoustic tools. Nevertheless, the proper interpretation of cement logs still requires extensive information about the well and the cement properties. Very low-density cement sheaths (foamed or otherwise) still pose a challenge.

Fig. P-9. Processing the log information requires teamwork between the operator, cement service company, and logging company. Cement sheath evaluation is presented in Chapter 15.
P-3.6 Mechanical properties of set cement

For many years, uniaxial compressive strength and tensile strength were the primary mechanical properties considered in well cementing. In rare cases, the flexural strength was determined. During the early 1980s, scientists and engineers began to estimate the cement-sheath integrity over the life of the well. Early on, researchers determined that well operations, completion practices, and production following the cement job had major effects on cement-sheath integrity. Since then, joint projects between the major cement service companies and many of the major operators have been performed to better understand the mechanical properties of well cements. The principal properties are listed below.

- Young's modulus
- Poisson’s ratio
- Plastic parameters
- Friction angle
- Flexural strength
- Tensile and compressive strength (triaxially loaded)

Based on the data collected, the major cement service companies developed modeling programs that determine the most appropriate cement-slurry design for a given set of well parameters. These programs require much more detailed information than was gathered in the past. There is also a task group in the API that is charged with developing a set of common test procedures to determine the desired mechanical properties of the cement sheath.

State-of-the-art modeling programs have shown that some of the conventional cement slurries have a high failure probability. The time window may be weeks, months, or years. This becomes a very important risk factor, because the life of a given well could be extended if it is properly cemented in accordance with its production capability and history. The mechanical properties of cements were given only limited attention in the first edition of this textbook. In this second edition, an entire chapter is devoted to the subject (Chapter 8).

P-4 Conclusions

In a short preface, it is impossible to cover all of the important technological advances. However, from this discussion, it is clear that significant progress has been made during the past decade. It should be noted that additional work is continuing in the area of well cementing. Our industry has met the challenges to improve, and will continue to do so in the future. Our goal is 100% job success, regardless of the type of cement job.

P-5 Acronym list

API American Petroleum Institute
ISO International Organization for Standardization

Fig. P-10. Mechanical properties of set cement.
The first edition of *Well Cementing* was published in 1990. Since then, cementing technology has advanced rapidly on many fronts, and Schlumberger decided to produce an updated edition.

Well cementing technology is an amalgam of many interdependent scientific and engineering disciplines, including chemistry, geology, and physics and petroleum, mechanical, and electrical engineering. Each is essential to achieve the primary goal of well cementing—durable zonal isolation. By preparing this second edition, the authors have aspired to produce a comprehensive and updated reference concerning the application of these disciplines toward cementing a well.

Like the first edition, this textbook comprises five principal sections. The first section (Chapter 1) illustrates how the quality of the hydraulic seal provided by the cement sheath can affect well performance. The second section (Chapters 2 through 11) presents information that must be considered during the design phase of a cementing treatment. Various aspects of cement job execution are covered in the third section (Chapters 12 through 14). The fourth section (Chapter 15) addresses cement job evaluation. The fifth section contains appendices that present information about rheology, cement testing, and cementing calculations.

In the preface, D.G. Calvert states that “primary cementing (is) the most important operation performed on a well.” Indeed, from operational experience, few would dispute that no other event has a greater effect on the production potential of a well. Yet it is interesting to note that very little work has been published regarding the quantification of zonal isolation from a reservoir engineering point of view. In Chapter 1, common reservoir engineering concepts are used to derive a theoretical index of zonal isolation, which can be used to calculate the maximum tolerable cement sheath permeability (matrix and interfacial). The index of zonal isolation concept is subsequently applied to typical wellbore scenarios, and the results further underscore the critical importance of cement sheath integrity. Chapter 1 also provides several examples of consequences suffered by operators when adequate zonal isolation is not attained.

Chapter 2 is concerned with the central unifying theme of this textbook—Portland cement. The physical and chemical properties and the performance of this remarkable material are crucial to every facet of well cementing technology. This chapter presents (in a well cementing context) a review of the manufacture, chemical composition, hydration chemistry, and classification of Portland cements. The updated discussion reflects an improved understanding of aluminate-phase hydration, and also includes a section concerning advanced techniques for monitoring and modeling cement hydration.

Well cementing exposes Portland cement to conditions far different from those anticipated by its inventor. Cement systems must be designed for placement under conditions ranging from below freezing in permafrost zones to greater than 1,000°F [538°C] in some thermal recovery wells. After placement, the cement systems must preserve their integrity and provide zonal isolation during the life of the well. It has only been possible to accommodate such a wide range of conditions through the development of additives that modify the behavior of Portland cements for individual well requirements. The impressive array of cement additives used in the well cementing industry is discussed in Chapter 3. The chemical nature of the various classes of additives is described, and typical performance data are provided. In addition, building upon the material presented in Chapter 2, the mechanisms by which the additives operate are also explained.

The rheology of well cement systems is examined in Chapter 4. A review of the relevant rheological models and concepts is presented, followed by discussions of flow in pipes and annuli, the effects of particle-laden fluids, foamed cement rheology, and equipment for rheological characterization.

The rheological behavior of a cement slurry must be optimized to effectively remove drilling mud from the annulus. The appropriate cement slurry design is a function of many parameters, including the wellbore geometry, casing hardware, formation integrity, drilling fluid characteristics, and presence of spacers and washes. A large amount of theoretical and experimental work con-
cerning mud removal has been performed since 1940, yet this subject remains controversial today. Chapter 5 is a review of the work performed to date, contrasting the opposing viewpoints and distilling some mud removal guidelines with which the majority of workers in this field would agree.

The interactions between cement systems and the formations with which they come into contact are important topics. Such interactions encompass four principal effects—fluid loss, formation damage, bonding, and lost circulation. It is generally acknowledged that an inappropriate level of fluid-loss control is often responsible for primary and remedial cementing failures. In addition, invasion of cement filtrate into the formation may be damaging to production. Chapter 6 discusses static and dynamic fluid loss, the deposition of cement filter cakes on formation surfaces, and the influence of a previously deposited mudcake on the fluid-loss process. Recent work concerning cement-to-formation bonding is also highlighted. Another section of Chapter 6 reviews methods for preventing or correcting lost circulation. Because lost circulation is best attacked before the cementing process is initiated, the treatment of this problem during drilling is also presented.

During the past 16 years, the cementing industry has rapidly expanded the number of special cement systems that address problems such as slurry fallback, lost circulation, and microannuli and salt-formation, permafrost, deepwater, and corrosive-well environments. These technologies are described in Chapter 7. The more notable systems discussed in the chapter include foamed cements, engineered particle-size distribution cements, flexible cements, cements containing blast-furnace slag, and cementitious drilling fluids. The compositions of the cement systems (several of which do not involve Portland cement) are explained, and typical performance data are provided.

Until recently, the well cementing industry was largely concerned with only one mechanical property of set cement—compressive strength. Today, we recognize that compressive strength alone is an insufficient indicator of a cement system’s ability to provide zonal isolation throughout the lifetime of a well and after abandonment. Consequently, a significant effort is under way to better understand the mechanical response of cement systems to downhole conditions. Chapter 8 discusses the industry’s current level of understanding. In this chapter, basic rock-mechanics concepts are presented in the context of well cements, followed by an examination of how these concepts may be applied to design appropriate cement systems for the anticipated downhole environment.

Annular fluid migration has been a topic of intense interest and controversy for many years, and a thorough review is presented in Chapter 9. This complex phenomenon may occur at any time during well construction, production, and abandonment, and it has long been recognized as one of the most troublesome problems of the petroleum industry. The causes and consequences of fluid migration are discussed, and theoretical and experimental models are described. In addition, methods to predict and solve fluid migration problems are presented.

The physical and chemical behavior of well cements changes significantly at high temperatures and pressures; consequently, special guidelines must be followed to design cement systems that will provide adequate casing protection and zonal isolation throughout the life of so-called “thermal wells.” In addition, the presence of corrosive zones and weak formations must frequently be considered. Thermal cementing encompasses three principal types of wells—deep oil and gas wells, geothermal wells, and thermal recovery (steamflood and fireflood) wells. In Chapter 10, each scenario is discussed separately, because the cement system design parameters can differ significantly. The chemistry of thermal cements, including newer systems that are not based on Portland cement, is also presented, and data are provided to illustrate the long-term performance of typical systems.

Proper mixing and placement of well cements rely upon the application of electrical and mechanical technology. Chapter 11 focuses on cementing equipment and casing hardware. In line with the trend toward deeper wells and more severe working environments, this technology has become increasingly sophisticated, and the equipment has become more flexible in application and more reliable in operation. First, an extensive discussion is presented concerning the various types of equipment for bulk handling, storage, cement mixing, and pumping. In addition, the special considerations for onshore and offshore cementing, as well as cementing in remote locations, are examined. The second section of this chapter is a discussion of the wide variety of casing hardware (float equipment, cementing plugs, stage tools, centralizers, scratchers, liners, etc.) and explains how these devices work. This presentation is supported by an extensive series of illustrations.

Chapters 2 through 11 contain information the engineer must consider when designing a cement system or choosing the proper equipment for the cementing treatment. Sophisticated computer programs are available to perform most job-design tasks; nevertheless, this has not diminished the need for simple engineering common
sense. The methodology by which an engineer may systematically develop an optimal cement job design is discussed in Chapter 12. Examples of job design procedures are also presented.

Chapter 13 is a presentation of primary cementing techniques. This chapter explains primary cementing terminology, the classification of casing strings, and the special problems associated with the cementation of each type of string. The cementing of large-diameter casings, multilaterals, expandable tubulars, horizontal wells, and liners, as well as stage cementing, is also covered.

Chapter 14 is devoted to remedial cementing techniques—plug cementing and squeeze cementing. The chapter begins by describing the types of well problems that can be cured by remedial cementing. The next section discusses plug cementing techniques and includes information about special tools and cement design guidelines. The third section presents squeeze cementing from both a theoretical and practical point of view. Placement techniques such as low- and high-pressure squeezes, Bradenhead squeezes, and hesitation squeezes are described. Finally, common misconceptions about remedial cementing, reasons for failure, and evaluation of remedial cementing jobs are discussed.

After a well has been cemented, the results are often evaluated to check whether the objectives have been reached. Chapter 15 is a comprehensive presentation of the available techniques to perform such evaluations. These include hydraulic testing; nondestructive methods such as temperature, nuclear, or noise logging; and acoustic and ultrasonic cement logging. The theoretical basis of each technique is discussed, the measuring devices are described, and the interpretation of the results is explained. The interpretation discussion is supported by many illustrations.

Three appendices are included in this textbook to supplement the material covered in the chapters. Appendix A is a digest of rheological equations commonly used in well cementing, presented in a tabular format. Appendix B is an updated examination of laboratory cement testing procedures and the equipment commonly used to perform such tests. This discussion describes many devices and techniques that were not available when the first edition was published. Appendix C is a presentation of common calculations for slurry design, primary and remedial cementing, and foamed cementing. Most of these calculations are performed today by software applications; nevertheless, this material has been included for the reader's reference.

It is important to mention that this edition of *Well Cementing* differs from its predecessor in terms of nomenclature. The text generally conforms to symbol guidelines published by the Society of Petroleum Engineers (SPE), and the editors have endeavored to give symbols a consistent meaning throughout the entire textbook. Consequently, the reader will notice that the symbols in many equations differ from those that appeared in the original referenced publications. Also, since this book encompasses many disciplines, symbol conflicts frequently occurred. To avoid confusion, this textbook presents a comprehensive nomenclature list and, where symbol conflicts exist, the meaning of the symbols in particular chapters is noted. For example, in rock mechanics, the symbol $E$ refers to Young's modulus while, for cement job evaluation, $E$ refers to acoustic waves. Therefore, $E$ denotes Young's modulus in Chapter 8 and the peak amplitude of the acoustic wave arrival in Chapter 15.

As stated earlier, this textbook was written to provide the reader with updated technical information concerning well cementing. Since work to produce this book began in late 2002, virtually all aspects of cementing technology have continued to advance at a rapid pace; consequently, we were obliged to continually revise and update many chapters until press time. While this has been somewhat exasperating for the authors, it is a strong indication of the industry's continuing commitment to the improvement of well cementing technology. We have attempted to present the material in a logical and easily understandable form and to reduce the aura of mystery that seems to be associated with many aspects of this technology. It is our fervent hope that this new edition of *Well Cementing* will be a useful addition to the reader's reference library.
1-1 Introduction

Production optimization begins with a good completion, and a good completion depends on the integrity of the primary cement job. About 15% of primary cement jobs fail, costing the oil and gas industry an estimated USD 450 million annually in remedial cementing work (Newman et al., 2001). Figure 1-1 shows the percentage of wells experiencing sustained casing pressure (SCP) versus age for the 22,000 wells in the U.S. Gulf of Mexico (personal communication, J. Levine, 2003). This means that there are 8,000 to 11,000 wells in the Gulf of Mexico with sustained SCP. In 1999, there were 3,810 wells with surface casing vent flows and 814 wells with gas migration problems in Alberta, Canada (Alberta Energy and Utilities Board, 1999).

The primary reason for these failures is improper balancing of the pressures, which allows gas and fluid influx into the cement-filled annulus during the primary cement job, and movement of pipe, cement, or both in the wellbore during depletion. Methods to improve primary cementing practices and prevent zonal-isolation failures will be discussed in later chapters. In this introductory chapter, the effect of cement job quality on the long-term performance of a well will be outlined.

Fig. 1-1. Gulf of Mexico wells with SCP (from personal communication, J. Levine, 2003).
Figure from U.S. Minerals Management Service.
1-2 Zonal isolation

Complete and durable zonal isolation is the foremost goal of the cement job. During the life of a producing oil and gas well, the quality of the cement job has a direct impact on the economic longevity of the well. From the time the well is first produced until the well is abandoned, appropriate cement-slurry design and placement techniques will affect well productivity, both physically and economically. If allowed to set undisturbed, Portland cement systems of normal density (≈16.0 lbm/gal or 1,930 kg/m³) usually exhibit extremely low matrix permeability. The literature quotes values in the microdarcy range. However, during the productive life of a well, the cement is subjected to various severe conditions that can affect the longevity of this low matrix permeability. The first condition, termed “cracking,” is caused by thermal or pressure fluctuations in the well caused by the production process. For example, gas wells are subjected to large variations in drawdown pressure and temperature as the gas demand changes. Depending on the magnitude and frequency of these production variables, the casing and cement sheath expand and contract in different ways (Chapter 8). This causes stress gradients that gradually crack cement, with the subsequent loss of cement integrity (Fig. 1-2).

The second condition, termed “debonding,” occurs when the bond between either the cement/rock or the pipe/cement interface fails. Several production practices can cause debonding:
- the gradual pressure decrease as a well is produced
- casing movement as subsidence occurs
- cement shrinkage with time
- temperature and pressure fluctuations
- stimulation practices, such as hydraulic fracturing.

Figure 1-3 shows images from a 4-arm caliper log in a well that has experienced severe casing movement. The cement in the region where movement occurred was destroyed, but a good primary cement job kept the undisturbed region intact and isolated.

The third condition, called “shear failure,” typically results in complete failure of the cement sheath. Shear failure is normally caused by effective-stress increases around a wellbore caused by rock subsidence and movement as the reservoir is depleted. This effect can also be caused by vibrations from downhole pumps or gas-lift operations.

Any of these conditions will result in flow paths in the form of discrete conductive fractures in the cement, or microannuli. These paths, and their effective widths, create cement permeabilities that far exceed the intrinsic permeability of the undisturbed cement. Even a small microannulus results in a large effective permeability along the cement sheath.

Fig. 1-2. Photograph of set cement that has undergone thermal fracturing.
1-2.1 Index of zonal isolation

Zonal isolation is the most important function of cement; however, the minimum necessary zonal isolation is not often quantified. In 1990, Economides proposed a simple way to attempt such an estimate. One can compare the producing rate of the active layer with the contributions of an overlying or underlying formation through breaches in the cement sheath. Consider the typical completion configuration shown in Fig. 1-4. In the middle is a perforated interval with two other potentially producing intervals (one above and one below) separated by some relatively impermeable layers, of thickness $\Delta L_1$ and $\Delta L_2$, respectively.

For simplicity, let us consider steady-state flow into the well from the producing layer. The equation describing this rate for a radial oil reservoir is easily derived from Darcy’s law and is given below in U.S. units.

\[
q_{res} = \frac{k_{res} h_{res} (p_{res} - p_{fkh})}{141.2 B_{res} \mu_{res} \left( \ln \frac{r_{res}}{r_{web}} + s_{res} \right)} \tag{1-1a}
\]

where

- $B_{res} =$ formation volume factor
- $h_{res} =$ thickness (ft)
- $k_{res} =$ permeability (mD)
- $p_{fkh} =$ flowing bottomhole pressure (psi)
- $p_{res} =$ reservoir pressure (psi)
- $q_{res} =$ flow rate (stb/D)
- $r_{res} =$ reservoir radius
- $r_{web} =$ wellbore radius
- $s_{res} =$ skin factor
- $\mu_{res} =$ viscosity (cp).

For a gas well, the analogous equation is

\[
q_{res} = \frac{k_{res} h_{res} \left( p_{res}^2 - (p_{fkh})^2 \right)}{1424 \mu_{res} Z_{res} T_{res} \left( \ln \frac{r_{res}}{r_{web}} + s_{res} \right)} \tag{1-1b}
\]

where

- $q_{res} =$ flow rate (Mscf/D)
- $T_{res} =$ reservoir temperature (°R)
- $Z_{res} =$ gas deviation factor.

Note that, for gas, the flow rate is proportional to the pressure squared.

Crossflow from the adjoining formations into the producing layer is likely to occur, because a pressure gradient is formed between them. The flow rate is proportional to the vertical permeability of the producing layer. For flow into the producing layer from another formation, the largest vertical pressure gradient would be at the cement sheath, which must have at least as low a
permeability as the barrier layers. From the geometry shown in Fig. 1-4, the flow area through the cement sheath is equal to

$$A = \pi \left[ (r_{wb})^2 - (r_{csg})^2 \right]. \quad (1-2)$$

Darcy’s law can be applied along the cement annulus. Thus, from the generalized expression

$$q = \frac{kA \Delta p}{\mu \Delta L}, \quad (1-3)$$

and replacing $A$ as given by Eq. 1-2, an expression giving the flow rate (in U.S. units) through the cement sheath can be obtained.

$$q_{\text{leak}} = \frac{k^* \pi \left[ (r_{wb})^2 - (r_{csg})^2 \right] \left[ (p_{\text{res}})_1 - p_{\text{fbh}} \right]}{141.2 (B_{\text{res}})_1 (\mu_{\text{res}})_1 (\Delta L_1)} \quad (1-4)$$

where

$(p_{\text{res}})_1 =$ adjoining reservoir pressure

$q_{\text{leak}} =$ flow rate (Mscf/D).

Analogous expressions to Eq. 1-4 can be readily derived for the flow of gas or water. In the case of gas, the expression is

$$q_{\text{leak}} = \frac{k^* \pi \left[ (r_{wb})^2 - (r_{csg})^2 \right] \left[ (p_{\text{res}})_1^2 - (p_{\text{fbh}})^2 \right]}{1424 \mu_j Z_{\text{res}} T (\Delta L_1)} \quad (1-5)$$

Equations 1-4 and 1-5 provide the oil and gas flow rate, whether through the cement sheath matrix permeability, through a microannulus formed between the cement and casing, or through the cement and the formation. The equivalent permeability value, $k^*$, can be related to width of the microannulus, as will be shown later.

Using Eq. 1-4, the leakage rate through the cement sheath can be estimated for various values of equivalent permeability. Table 1-1 contains some typical values from reservoir and well data. The distance between the target reservoir and an adjoining formation, $\Delta L_1$, is taken as equal to 20 ft. Figure 1-5 is a graph of the steady-state oil flow rate for a range of equivalent permeability, using the data in Table 1-1. Figure 1-6 is an analogous example of a gas well, using the data in Table 1-2 and Eq. 1-5. For an ideal, low-permeability cement sheath bonded to the casing and formation, the leakage rates are negligible. When a microannulus exists at the cement-formation interface, the situation is completely different.

### Table 1-1. Well and Reservoir Data for Oil Flow Along the Cement Sheath

<table>
<thead>
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<th>Parameter</th>
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<tbody>
<tr>
<td>$r_{\text{wb}}$</td>
<td>0.406 ft (9¾-in. OD)</td>
</tr>
<tr>
<td>$r_{\text{csg}}$</td>
<td>0.328 ft (7¾-in. OD)</td>
</tr>
<tr>
<td>$p_{\text{res}}$</td>
<td>3,000 psi</td>
</tr>
<tr>
<td>$B_{\text{res}}$</td>
<td>1.1 bbl at reservoir conditions/stb</td>
</tr>
<tr>
<td>$\mu_{\text{res}}$</td>
<td>1 cp</td>
</tr>
<tr>
<td>$\Delta L_1$</td>
<td>20 ft</td>
</tr>
<tr>
<td>$p_{\text{fbh}}$</td>
<td>1,000 psi</td>
</tr>
</tbody>
</table>

**Fig. 1-5.** Oil flow rate along the cement sheath for a range of annular equivalent permeabilities.

**Fig. 1-6.** Gas flow rate along the cement sheath for a range of annular equivalent permeabilities.
In a consistent unit system, the microannulus permeability is given by

\[ k = \frac{w^2}{12}, \] (1-6)

where \( w \) is the annulus width.

However, the equivalent annular permeability, defined by Eq. 1-5, is

\[ k^* = k_{cem} + \frac{r_{wb}w^3}{12\left[r_{wb} - r_{csg}\right]^2}, \] (1-7a)

because the relevant parameter is the product of the permeability and the cross-sectional area. When expressing permeabilities in millidarcies, radii in feet, and width in inches, Eq. 1-6 becomes

\[ k^* = k_{cem} + \left(\frac{4.54 \times 10^9}{\pi}\right)\frac{r_{wb}w^3}{\left[r_{wb} - r_{csg}\right]^2}. \] (1-7b)

Using the wellbore geometry given in Table 1-1 and assuming a microannulus width of 0.002 in. [51 \( \mu m \)], the second term of the right-hand side of Eq. 1-7b is equal to 2.54 \times 10^{-13} \text{ m}^2 or 258 mD. Therefore, in the presence of a microannulus, cement permeability can be a negligible portion of the equivalent permeability. And, as can be seen from Figs. 1-5 and 1-6, the leakage rates are then substantial. These leakage rates can be compared to the flow rate from the producing formation. For simplicity, we will now assume that in Eq. 1-4, the fluid and the reservoir pressure in the adjoining layer are the same as in the producing formation. Dividing Eq. 1-1a by Eq. 1-4, the ratio of the flow rate into the well from the intended formation to the flow rate through the cement is defined as the index of zonal isolation \((I_{ZI})\) and is given in Eq. 1-8.

\[ I_{ZI} = \frac{q_{res}}{q_{leak}} = \frac{k_{res}k_{res}(\Delta L_1)}{k\pi \left[\left(r_{wb}\right)^2 - \left(r_{csg}\right)^2\right] \left[\ln \left(\frac{r_{wb}}{r_{csg}}\right) + s\right]}, \] (1-8)

Interestingly, all variables that distinguish Eq. 1-1a (for oil and water) and Eq. 1-1b (for gas) are the same as those evident in Eq. 1-4 (for oil and water) and Eq. 1-5 (for gas). Thus, the \( I_{ZI} \) expression as given by Eq. 1-8 is valid for any fluid.

Equation 1-8 can provide the quantification of zonal isolation. It can be used either to calculate the required cement equivalent permeability to provide a desired flow-rate ratio or, for a given cement permeability, what the flow rate would be through the cement sheath from adjoining layers. As discussed earlier, the equivalent cement permeability, \( k^* \), is an equivalent permeability value, resulting either from the presence of a microannulus or from an unnaturally high cement-matrix permeability. The latter may be caused by the disruptive effects of fluid invasion as the cement changes from liquid to solid (Chapter 9). While a large matrix permeability within the cement sheath is unlikely (for the magnitudes shown in Figs. 1-5 and 1-6), a large equivalent permeability can result from a relatively small microannulus width.

Equation 1-8 can also be used as an evaluation tool to detect flow through the cement sheath. If a vertical-interference or a multilayer test is performed and the reservoir is well defined, then crossflow through the adjoining low-permeability layers may be calculated (Ehlig-Economides and Ayoub, 1986). As a result, the ideal flow rate from the targeted interval can be calculated.

Deviations from this value can be attributed to flow through an imperfect cement sheath, assuming that the cement-sheath leak was not active when the vertical interference test was run. Using Eqs. 1-1a or 1-1b, the permeability of the cement can then be extracted. The net flow rate through the perforated interval is

\[ q = q_{res} + \sum q_{cf} + \sum q_{leak}, \] (1-9)

where

\[ q_{res} = \text{lateral reservoir flow rate} \]

\[ \sum q_{cf} = \text{the sum of crossflow contributions through the barrier} \]
\( \Sigma q_{\text{leak}} \) = the sum of contributions through the cement sheath.

Figure 1-7 is a graph for an example well using an 80-acre spacing, a skin effect equal to 5, and a wellbore radius of 0.406 ft. The product \( k_{\text{res}} h_{\text{res}} \Delta L_1 \) is graphed on the abscissa while the equivalent cement permeability is graphed on the left ordinate. On the right ordinate is the equivalent path width squared that would result in a similar flow rate. Two curves are offered: one for 50% and another for 100% of the \( \%_{\text{vol}} \) ratio \( (I_{ZI}) \). As can be seen, the cement permeability requirements and the need for more zonal isolation become more critical for lower-permeability producing formations that are separated by thin barriers. In both cases, the product \( k_{\text{res}} h_{\text{res}} \Delta L_1 \) becomes small, requiring a small cement-sheath permeability. The low product is not a problem if only the innate matrix permeability of the cement sheath is considered. For most cements, this permeability is less than 0.01 mD.

However, the presence of a continuous microannulus can severely aggravate the situation. The width cubed of the microannulus is graphed on the right ordinate of Fig. 1-7. For a typical reservoir \( (k_{\text{res}} = 4 \text{ mD}, h_{\text{res}} = 50 \text{ ft}, \Delta L_1 = 50 \text{ ft}) \), resulting in \( k_{\text{res}} h_{\text{res}} \Delta L_1 = 10^4 \) with a flow rate ratio of 50, the microannulus width must be less than 0.0014 in. (35 \( \mu \)m), which corresponds to an equivalent permeability of 86 mD. These calculations clearly demonstrate the extreme importance of obtaining an intimate bond between the cement sheath and casing and formation surfaces.

The quantified \( I_{ZI} \) then becomes an important variable to control. For tight reservoirs, if only absolute contributions or losses from or into adjoining formations are of concern, then a low \( I_{ZI} \) can be tolerated. However, it should be remembered, especially when influx of foreign fluids such as gases, water, or oil of different physical properties is evident, the minimum tolerable \( I_{ZI} \) may be very high and contingent on the production facilities at the wellhead. In such cases, even more stringent \( I_{ZI} \) requirements may be necessary in tight, thinly separated formations, as implied in Eq. 1-8.

The ability of cement to withstand the expansion and contraction of the tubing string is directly related to the composition of the original cement. As wells are cycled, cement experiences fatigue. This can be overcome to a certain extent through the use of flexible cements, as described in Chapters 7 and 8.

The effects of cement failure on the long-term viability of a well or even a field can be drastic. A poor cement job in a pressure-maintenance or enhanced oil recovery well (water, miscible injection fluid, polymer, steam, etc.) allows injection fluid to be introduced into zones in which it is not needed. This can result in severe and costly environmental, drilling, and longer-term production problems. When this occurs, the injection fluid will normally migrate to the highest-permeability region, allowing a “short circuit” to form in the system. This results in poor sweep efficiency, wasted injection fluid, and shortened well life. A short circuit to adjacent wells can also result in a breach to surface. A secondary effect

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**Fig. 1-7.** Example of the \( I_{ZI} \) concept.
is the overpressuring of shallow sands, resulting in drilling hazards and blowout issues when additional field development is needed.

1-3 Water and gas influx

During the production period, the sudden appearance of excessive amounts of water, gas, or both in the annulus is a strong indication of cement failure. The effects of this failure are numerous and include lost production revenue, hazardous operations, supercharging of shallow water sands, and hazardous conditions around the wellhead. Table 1-3 offers a quick diagnostic tool to determine the causes of gas influx (personal communication, L. Moran, 2003). Goodwin and Crook (1990) provide a good discussion of why the cement sheath fails in areas where high-temperature or high-pressure fluctuations occur in the well. The main mechanism they describe for cement-sheath failure under excessive temperature and pressure is the expansion of the casing both diametrically and circumferentially. The circumferential expansion creates a shearing force at the cement-casing interface, causing failure at the interface or fracturing of the cement sheath radially from the inner casing surface to the outer casing or formation surface. Laboratory testing showed that all cement systems exposed to casing expansion exhibited failure, ranging from the creation of stress fractures running either parallel or perpendicular to the inner casing surface to total structural failure, in which the cement was reduced to putty. The point at which failure occurred and the nature of the failure were functions of specific parameters of the cement, including elasticity and compressive strength. Their work, presented in Chapter 8, also provides a simple model to calculate the magnitude of casing expansion that can lead to cement failure.

In addition to gas, failed cement can allow water to invade the annulus. Although not as dangerous as gas, uncontrolled water invasion can have numerous negative consequences. Corrosion of tubulars can occur, shortening the useful life of the well. The water content of the produced fluids may increase, raising the lifting and disposal costs. In addition, contamination of freshwater aquifers is a serious environmental consequence.

1-4 Impact on artificial-lift operations

The purpose of artificial lift is to increase flow from the reservoir by lowering the bottomhole pressure at the production zone. This reduced pressure increases the stress on the cement. If the cement job is poor, channels can form that connect with zones other than the desired producing interval.

Communication with other zones can result in the production of unwanted fluid, either water or gas, which will affect the lift equipment. The lift equipment may be undersized for the greater amount of fluid or gas. Unless corrective actions are taken, the desired bottomhole pressure cannot be achieved, resulting in lower than expected production rates. In severe cases, a poor cement job that communicates with a water zone or a deeper aquifer can create water coning, seriously reducing the ultimate recovery of the resource. Many types of lift equipment subject the produced fluids to relatively high-shear conditions. If water is introduced into the system, water-in-oil emulsions can form, drastically reducing the pump efficiency. If the introduced water is incompatible with the formation water, scale can precipitate, reducing pump efficiency and eventually causing pump blockage.

Likewise, depending on the type of lift equipment employed, communication into a gas zone creates problems. Free gas decreases the performance of all the pumps used to lift fluid. Excessive gas can reduce run times, cause frequent shutdowns, and, in the worst case, cause sufficient cavitation to destroy the pump.

Table 1-3. Gas Influx Diagnostic Table†

<table>
<thead>
<tr>
<th>Symptom</th>
<th>Cause</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas flows immediately.</td>
<td>The well is underbalanced or a gas zone exists above the cement top.</td>
</tr>
<tr>
<td>Gas appears 3 to 12 hr after the cement job.</td>
<td>The cement lost hydrostatic pressure during the setting process and allowed gas influx.</td>
</tr>
<tr>
<td>Gas appears in a day to a few days after the cement job.</td>
<td>A microannulus formed between the cement and casing or formation.</td>
</tr>
<tr>
<td>Gas appears months to years after the cement job.</td>
<td>The well suffered a loss of hydrostatic pressure in a channeled mud column, the cement is highly permeable, or the cement was damaged during the production process.</td>
</tr>
</tbody>
</table>

† From personal communication, L. Moran, 2003
1-5 Matrix stimulation and hydraulic fracturing

The cement-to-pipe bond is a very important consideration when matrix stimulation or hydraulic fracturing treatments are attempted. It is critical that the cement sheath provide zonal isolation above and below the zone of interest. Unfortunately, and surprisingly, this is an area of research that has not received sufficient attention. Handin (1965) and Banthia (2003) attempted to characterize the “strength” of well cements at downhole pressure and temperature conditions. Handin (1965) characterized the compressive strength of cements and determined the ultimate strength at failure. He concluded that oilwell cements become ductile, even under low effective confining pressures. Because of the magnitude of ultimate compressive strengths at normal system densities, these cements have mechanical constitutive properties similar to that of sedimentary rocks under similar confining conditions. Banthia studied the performance of fiber-reinforced cement systems and found that the toughness parameters were strongly influenced by the load conditions.

The perforating process can shatter the cement sheath in the immediate vicinity of the perforating-charge detonation. Later, when a fluid is injected into a reservoir at a pressure greater than the fracture gradient, such as during hydraulic fracturing or water injection operations, the failure mechanism is tensile, and the cement sheath is potentially subjected to two phenomena. The first is fracture propagation within the cement sheath beyond the perforations, and the second is debonding of the cement sheath from the pipe. In either case, the net result is the creation of a microannulus. Depending on the formation strength compared to the cement and the net pressure created during the treatment, the fracture created in the cement can have a width of the same order as the induced fracture in the rock.

Figure 1-8 shows a tracer log of a well following a hydraulic fracturing treatment. Both the pad stage (iridium = red) and 2–4 ppa proppant stage (antimony = blue) were contained within the zone of interest. However, during the 4–8 ppa proppant stage (scandium = yellow), the fracture grew down into a deeper sand. The crack between the upper and lower zone was of sufficient width to conduct the proppant into the lower sand. The interpretation of this log is that the cement failed during the third stage of the hydraulic fracturing treatment. This indicates that the cement-to-pipe or cement-to-formation bond strength was insufficient.

Parcevaux and Sault (1984) showed that there is no apparent correlation between the cement compressive strength and the shear-bond strength. Furthermore, they determined that the shear-bond strength ranges from 1,000 psi (about 7 MPa) for standard cement to 1,800 psi [about 12 MPa] for cements containing bond-enhancing agents (BA) as shown in Fig. 1-9. These values imply that, for many reservoirs in which the tensile strength of the rock is greater than 1,000 psi [about 7 MPa], the cement-to-pipe bond will fail first, resulting in a microannulus along the pipe. This has major implications for the loss of stimulation fluids (acid, scale inhibitors, fracturing fluids, etc.) as well as the migration of reservoir fluids following the treatment. In such a situation, remedial cementing would be indicated.

1-6 Logging

Many types of cased-hole wireline logs depend on good cement-to-casing and cement-to-rock bonds to provide accurate data. The absence of good bonding causes erratic tool response and makes interpretation difficult. In the case of sonic logs, the wave train will be reflected back to the tool in a manner termed “ringing,” which masks the sonic response of the reservoir. This same response, used at a higher frequency, is the principal technique used in cement bond logs to determine where good cement coverage exists. If a microannulus is present in the cement, the cased-hole resistivity log can also be misinterpreted. For example, if brine has migrated into a cement microannulus in a hydrocarbon-bearing zone, the resistivity log would indicate low resistivity, and the zone would be interpreted as water-saturated. Pulsed neutron tools have very shallow depths of investigation. If the wellbore has a poor cement job or thick casing, the results may be erroneous. Chapter 15 offers a complete discussion of these topics.
Despite recent advances in the cementing of oil and gas wells, many of today’s wells are at risk. Failure to isolate sources of hydrocarbons early in the well-construction process, or later after production has begun, has resulted in abnormally pressured casing strings. In addition, gas and produced water can contaminate other subsurface zones, such as freshwater aquifers. This results in wells that are environmentally and operationally hazardous. The well’s revenue stream can also be interrupted or reduced because of the loss of lift efficiency in the pump, excess-water or gas-handling issues.

1-7 Conclusions

Despite recent advances in the cementing of oil and gas wells, many of today’s wells are at risk. Failure to isolate sources of hydrocarbons early in the well-construction process, or later after production has begun, has resulted in abnormally pressured casing strings. In addition, gas and produced water can contaminate other subsurface zones, such as freshwater aquifers. This results in wells that are environmentally and operationally hazardous. The well’s revenue stream can also be interrupted or reduced because of the loss of lift efficiency in the pump, excess-water or gas-handling issues,

Fig. 1-8. Tracer survey showing fracture-height growth into lower sand (courtesy of ProTechnics, a division of Core Laboratories L.P.).

Fig. 1-9. Cement shear bond strength development at 68°F [20°C].

Chapter 1 Implications of Cementing for Well Production and Performance 21
inefficient remediation or stimulation treatments, and potential loss of the well owing to casing collapse. The environmental impact of contaminating a single freshwater aquifer is extremely serious. Therefore, the initial and long-term quality of the cement sheath and bond should be of prime importance to the operator, because it is essential for the safe and successful production of a well.

1-8 Acronym list

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>BA</td>
<td>Bond-enhancing agents</td>
</tr>
<tr>
<td>BVOS</td>
<td>By volume of solids</td>
</tr>
<tr>
<td>SCP</td>
<td>Sustained casing pressure</td>
</tr>
</tbody>
</table>
2-1 Introduction

Ordinary Portland cement (OPC) is by far the most important oilwell binding material in terms of quantity produced; indeed, it is possibly the most abundant manufactured material. The term “ordinary” indicates that the cement is manufactured in a rotary kiln from a molten matrix of suitably proportioned ingredients. OPC is used in nearly all well cementing operations; therefore, throughout this textbook, the terms OPC and Portland cement shall be used interchangeably.

The conditions to which Portland cements are exposed in a well differ significantly from those encountered at ambient conditions during construction operations; as a result, special Portland cements are manufactured for use as well cements. Certain other special cements, used to solve particular well cementing problems, are discussed in Chapters 7 and 10.

Portland cement is the most common example of a hydraulic cement. Such cements set and develop compressive strength as a result of hydration, involving chemical reactions between water and the compounds present in the cement. The setting and hardening occur not only if the cement/water mixture is left to stand in air, but also if it is placed underwater. The development of strength is predictable, uniform, and relatively rapid. The set cement also has low permeability and is nearly insoluble in water; therefore, exposure to water does not destroy the hardened material. Such attributes are essential to achieve and maintain zonal isolation.

This chapter presents fundamental information regarding the manufacture, hydration, and classification of Portland cements. In addition, the effects of various chemical and physical parameters upon performance are discussed. Several excellent textbooks were relied upon heavily to produce this overview of cement technology: Taylor (1964); Ghosh (1983); Taylor (1997); Hewlett (2001); and Bensted and Barnes (2002).

2-2 Chemical notation

A special chemical notation established by cement chemists is frequently used in this textbook. The chemical formulas of many cement compounds can be expressed as a sum of oxides; for example, tricalcium silicate, Ca$_3$SiO$_5$, can be written as 3CaO • SiO$_2$. Abbreviations are given for the oxides most frequently encountered, such as C for CaO (lime), S for SiO$_2$ (silica), and A for Al$_2$O$_3$ (alumina). Thus Ca$_3$SiO$_5$ becomes C$_3$S. A list of abbreviations is given below.

- C = CaO
- F = Fe$_2$O$_3$
- N = Na$_2$O
- P = P$_2$O$_5$
- A = Al$_2$O$_3$
- M = MgO
- K = K$_2$O
- f = FeO
- S = SiO$_2$
- H = H$_2$O
- L = Li$_2$O
- T = TiO$_2$

Others are sometimes used, such as $\bar{S} = SO_3$ and $\bar{C} = CO_2$. This convention of using a shortened notation was adopted as a simple method for describing compounds whose complete molecular formulas occupy much space when written.

2-3 Portland cement manufacture

Portland cement is produced by pulverizing clinker. Clinker is the calcined (burned) material that exits the rotary kiln in a cement plant. Clinker consists primarily of hydraulic calcium silicates, calcium aluminates, and calcium aluminoferites. One or more forms of calcium sulfate (usually gypsum, CaSO$_4$) are interground with the clinker to make the finished product. Materials used in the manufacture of Portland cement clinker must contain appropriate amounts of calcium, silica, alumina, and iron compounds. During manufacture, frequent chemical analyses of all materials are made to ensure uniformity and high quality.
2-3.1 Raw materials
Two types of raw materials are needed to prepare a mixture that will produce Portland cement clinker: *calcareous* materials, which contain lime, and *argillaceous* materials, which contain alumina, silica, and iron oxide. Depending upon the location of the cement plant, a great variety of natural and artificial raw materials is employed (Table 2-1).

The most important calcareous materials are sedimentary and metamorphic limestones, coral, shell deposits, and “cement rock,” which naturally has a composition similar to Portland cement. Artificial calcareous materials include precipitated calcium carbonate and other wastes from various industrial processes.

Natural argillaceous materials frequently used as raw materials include clays, shales, marls, mudstones, slate, schist, volcanic ashes, and alluvial silt. Blast-furnace slag from steelworks and fly ash from coal-fired power plants are the most important artificial sources.

The properties of Portland cement are determined by the mineralogical composition of the clinker. The mineralogical composition of conventional Portland cement clinker is shown in Table 2-2. For special cements, the content of $C_3A$ and $C_4AF$ can differ significantly. The main oxides make up about 95%:

- $CaO$ 60–70%
- $SiO_2$ 18–22%
- $Al_2O_3$ 4–6%
- $Fe_2O_3$ 2–4%.

### Table 2-1. Various Raw Materials Used in the Manufacture of Portland Cement

<table>
<thead>
<tr>
<th>Calcium</th>
<th>Iron</th>
<th>Silica</th>
<th>Alumina</th>
<th>Sulfate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alkali waste</td>
<td>Blast-furnace flue dust</td>
<td>Calcium silicate</td>
<td>Aluminum-ore refuse</td>
<td>Anhydrite</td>
</tr>
<tr>
<td>Calcite</td>
<td>Clay</td>
<td>Cement rock</td>
<td>Bauxite</td>
<td>Calcium sulfate</td>
</tr>
<tr>
<td>Cement-kiln dust</td>
<td>Iron ore</td>
<td>Clay</td>
<td>Cement rock</td>
<td>Gypsum</td>
</tr>
<tr>
<td>Cement rock</td>
<td>Mill scale</td>
<td>Fly ash</td>
<td>Clay</td>
<td></td>
</tr>
<tr>
<td>Chalk</td>
<td>Ore washings</td>
<td>Fuller's earth</td>
<td>Copper slag</td>
<td></td>
</tr>
<tr>
<td>Clay</td>
<td>Pyrite cinders</td>
<td>Loess</td>
<td>Fly ash</td>
<td></td>
</tr>
<tr>
<td>Fuller's earth</td>
<td>Shale</td>
<td>Marl</td>
<td>Fuller's earth</td>
<td></td>
</tr>
<tr>
<td>Limestone</td>
<td>Ore washings</td>
<td>Loess</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Marble</td>
<td>Quartzite</td>
<td>Ore washings</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Marl</td>
<td>Rice-hull ash</td>
<td>Shale</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Seashells</td>
<td>Sand</td>
<td>Slag</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Shale</td>
<td>Sandstone</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Slag</td>
<td>Shale</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Trappe!c</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

† Most common sources

### Table 2-2. Mineralogical Composition of Classic Portland Cement Clinker

<table>
<thead>
<tr>
<th>Oxide Composition</th>
<th>Cement Notation</th>
<th>Common Name</th>
<th>Concentration (wt%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$3CaO \cdot SiO_2$</td>
<td>$C_3S$</td>
<td>Alite</td>
<td>55–65</td>
</tr>
<tr>
<td>$2CaO \cdot SiO_2$</td>
<td>$C_2S$</td>
<td>Belite</td>
<td>15–25</td>
</tr>
<tr>
<td>$3CaO \cdot Al_2O_3$</td>
<td>$C_3A$</td>
<td>Aluminate</td>
<td>8–14</td>
</tr>
<tr>
<td>$4CaO \cdot Al_2O_3 \cdot Fe_2O_3$</td>
<td>$C_4AF$</td>
<td>Ferrite phase</td>
<td>8–12</td>
</tr>
</tbody>
</table>
The total content of minor compounds such as CaO (free lime), MgO, K₂O, Na₂O, TiO₂, Mn₂O₃, and SO₃ is normally under 5%.

When selecting the raw materials and kiln fuels, it is important to consider impurities that can have significant effects on the properties of the finished cement. These include manganese, magnesia (M), chlorides, phosphates, lead oxide, zinc oxide, alkalis, and fuel residues. After clinkering in the kiln, such impurities are often in solid solution within the principal cement phases, resulting in a change of reactivity. When present in quantities exceeding about 0.5 wt%, manganese can lead to the development of excessively large alite crystals, which may retard strength development. Excess magnesia (more than 5%) can cause a disruptive delayed expansion of the set cement, a condition known as “unsoundness.” Chlorides are generally limited to 0.015%, because they are volatile and can cause serious difficulties in the burning zone of the kiln. The presence of more than 0.1% fluorine in the raw materials, usually as calcium fluoride, results in a significant decrease in cement strength. Phosphates can have a beneficial effect on strength at a level of 0.20% to 0.25%; however, they have a deleterious effect at concentrations exceeding 0.5%. Lead and zinc oxides have a deleterious effect upon cement properties. The effect of alkalis is variable. The total alkali content, expressed as sodium oxide equivalent (%Na₂O + [0.658 × %K₂O]), generally should not exceed 0.6% in concrete applications, because of adverse reactions with certain types of siliceous aggregates.

2-3.2 Raw material preparation

Before calcination in the kiln, the raw materials must first be pulverized to a fine powder and uniformly blended to ensure that the bulk composition corresponds to that required to manufacture a particular type of Portland cement. Raw material homogenization is a very important technological operation, because the kiln feed should have a very stable chemical composition. Although each cement plant has its own specific method, there are two general processes in use today: the dry process and the wet process. In the dry process, grinding and blending are done with dry materials. In the wet process, the grinding and blending operations use a watery slurry.

A schematic diagram of the dry process is shown in Fig. 2-1. The raw materials are crushed, dried in rotary driers, proportioned to obtain the correct bulk composition, and then ground in a roller mill that combines crushing, grinding, drying, and size classification in one unit. The ground material is stored in several silos. The chemical composition varies from silo to silo; therefore, the mixture that goes into the kiln may require reblanding and fine-tuning.

![Fig. 2-1. Schematic flow diagram of dry process (from Portland Cement Association, 2002).](image-url)
The wet process is illustrated in Fig. 2-2. The raw materials are initially proportioned in the dry state. Water is added, and further size reduction occurs in a grinding mill. Size classification is performed by pumping the resulting slurry past a vibrating screen. Coarser material is returned to the mill for regrinding. The slurry is stored in basins equipped with rotating arms and compressed air agitation to keep the mixture homogeneous. The chemical composition of the slurries varies slightly from basin to basin. Thus, final adjustments of composition are performed by blending the slurries from various basins.

For many years, the wet process was preferred because more accurate control of the raw mix was possible; however, the dry process has become predominant because of the lower heat consumption, a typical value being 3,000 kJ/kg of clinker for dry and 5,500 kJ/kg for wet material. In recent years, the technology has been developed to obtain excellent control of raw material composition using the dry process.

### 2-3.3 Heat treatment

After achieving the appropriate degree of size reduction, classification, and blending of the raw materials, heat treatment is performed in a rotary kiln that is usually preceded by a preheater in more modern cement plants. This step is shown in Fig. 2-3. The kiln is slightly inclined and rotates at 1 to 4 rpm; as a result, the solid material passes through the kiln as it rotates.

Production of clinker involves burning fossil fuels to calcine large amounts of limestone. As a result, large quantities of CO₂ are released to the atmosphere. Today, cement producers are proactively working to reduce the emission of greenhouse gases. Foremost among the methods being employed is improved fuel-burning efficiency. By using less fuel per ton of clinker produced, CO₂ generated from fuel burning is reduced. In recent years, alternative fuels such as waste oil and old rubber tires have been used. Alternative raw materials that contain calcium but have been calcined in a previous manufacturing process are also used.

![Fig. 2-2. Schematic flow diagram of wet process (from Portland Cement Association, 2002).](image)

![Fig. 2-3. Schematic flow diagram of the burning process (from Portland Cement Association, 2002).](image)
Cement kilns are also used for the destruction of hazardous wastes. The neutralization and destruction of these substances is much more effective in a cement kiln than traditional industrial incinerators. In addition, some waste solvents can act as fuel in the kiln.

A complex series of reactions takes place in the kiln to convert the raw materials to clinker. There are six temperature zones in a kiln, and the temperature ranges and reaction profiles are shown in Table 2-3. The clinker production process from raw feed to final product is shown in Fig. 2-4.

Evaporation of free water occurs in Zone I. Water removal occurs quickly in the dry process; however, up to one-half the length of the kiln can be devoted to drying with a wet-process system. During preheating (Zone II), dehydroxylation of the clay minerals occurs. In Zones III and IV, several important reactions occur. Dehydroxylation of clay minerals is completed, and the products crystalize. Calcium carbonate decomposes to free lime, releasing large quantities of carbon dioxide. The production of various calcium aluminates and ferrites also begins. The sintering zone, Zone V, occupies a small portion of the kiln; however, most of the principal cement phases are produced at this stage. At this point, part of the reaction mixture liquefies. At the maximum temperature in the sintering zone, also known as the “clinkering temperature,” the formation of $C_2S$ and $C_3S$ is completed. The uncombined lime, alumina, and iron oxide are contained in the liquid phase. During the cooling phase (Zone VI), the liquid phase disappears, resulting in the crystallization of $C_3A$ and $C_4AF$. Some residual free lime is always present in the clinker.

### Table 2-3. Reaction Zones in a Rotary Cement Kiln

<table>
<thead>
<tr>
<th>Zone</th>
<th>Approximate Temperature Range ($^\circ F/^\circ C$)</th>
<th>Reaction Profile</th>
</tr>
</thead>
<tbody>
<tr>
<td>I</td>
<td>Up to 390 [700]</td>
<td>Evaporation</td>
</tr>
<tr>
<td>II</td>
<td>390 to 1,470 [200 to 800]</td>
<td>Preheating</td>
</tr>
<tr>
<td>III</td>
<td>1,470 to 2,010 [800 to 1,100]</td>
<td>Decarbonation</td>
</tr>
<tr>
<td>IV</td>
<td>2,010 to 2,370 [1,100 to 1,300]</td>
<td>Exothermic reactions</td>
</tr>
<tr>
<td>V</td>
<td>2,370 to 2,820 to 2,370 [1,300 to 1,550 to 1,300]</td>
<td>Sintering</td>
</tr>
<tr>
<td>VI</td>
<td>2,370 to 1,830 [1,300 to 1,000]</td>
<td>Cooling</td>
</tr>
<tr>
<td>Cross-Section View of Kiln</td>
<td>Nodulization Process</td>
<td>Clinkering Reactions</td>
</tr>
<tr>
<td>---------------------------</td>
<td>----------------------</td>
<td>----------------------</td>
</tr>
<tr>
<td><strong>To 1,292°F (700°C):</strong> Raw materials are free-flowing powder.</td>
<td>Particles are solid and do not react with each other.</td>
<td>Water is lost. Dehydrated clay recrystallizes.</td>
</tr>
<tr>
<td><strong>1,292–1,652°F (700–900°C):</strong> Powder is still free-flowing.</td>
<td>Particles are still solid.</td>
<td>As calcination continues, free lime increases. Reactive silica combines with CaO to begin forming C₃S. Calcination maintains feed temperature at 1,582°F (850°C).</td>
</tr>
<tr>
<td><strong>2,102–2,192°F (1,150–1,200°C):</strong> Particles start to become “sticky.”</td>
<td>Reactions begin between solid particles.</td>
<td>When calcination is complete, temperature increases rapidly. Small belite crystals form from the combination of silicates and CaO.</td>
</tr>
<tr>
<td><strong>2,192–2,462°F (1,200–1,350°C):</strong> As particles start to agglomerate, the liquid holds them together. The rotation of the kiln initiates coalescing of agglomerates and layering of particles.</td>
<td>The capillary forces of the liquid keep particles together.</td>
<td>Above 2,282°F (1,250°C), a liquid phase is formed. Liquid allows reaction between belite and free CaO to form alite.</td>
</tr>
<tr>
<td><strong>2,462–2,642°F (1,350–1,450°C):</strong> Agglomeration and layering of particles continue.</td>
<td>Nodules will form with sufficient liquid. Insufficient liquid will result in dusty clinker.</td>
<td>Belite crystals decrease in amount but increase in size. Alite increases in size and amount.</td>
</tr>
<tr>
<td><strong>Cooling</strong></td>
<td>Clinker nodules remain unchanged.</td>
<td>Upon cooling, the C₃A and C₅AF crystallize in the liquid phase. Lamellar structure appears in belite crystals.</td>
</tr>
</tbody>
</table>

*Fig. 2-4. Process of clinker production from raw feed to the final product (from Portland Cement Association, 2002).*
2.3.4 Cooling
The quality of the clinker and the finished cement is very dependent on the thermal profile and particularly upon the cooling rate. The best clinker is obtained by cooling slowly to about 2,282°F [1,250°C], followed by rapid cooling, usually 32° to 36°F/min [18 to 20°C/min].

When the cooling rate is slow, 7° to 9°F/min [4° to 5°C/min], the C3A and C4AF develop a high degree of crystallinity, the C3S and C2S crystals become highly ordered, and the free MgO forms crystals (mineral name: periclase). This results in a cement that is less hydraulically active. When hydrated at ambient temperatures, early compressive strength is high, but longer-term strength is low.

When the cooling rate is fast, the liquid phase formed at Zone V in the kiln solidifies to a glass. The C3A and C4AF remain trapped in the glassy phase, and the crystallinity of the C3S and C2S is less ordered. The free MgO also remains in the glassy phase; as a result, it is less active and the resulting cement is less apt to demonstrate unsoundness. Early compressive strength is lower, but longer-term strength is higher.

The general behavior described above is based upon general observations of cement behavior at ambient conditions. For well cements, larger C3S and MgO crystals are usually preferred (personal communication, B. Carruthers, 2002).

Figures 2-5 and 2-6 are microscope photographs of a typical Portland cement clinker and finished Portland cement, respectively. Figure 2-5 is a polished thin section of clinker. Alite (C3S) appears as light, angular crystals. The darker, rounded crystals are belite (C2S). Figure 2-6 is an example of an advanced two-dimensional microscopic technique that allows visualizing more of the phases. The image was obtained by combining a set of backscattered scanning electron and X-ray images and producing a computer-generated map with different colors assigned to the individual phases (National Institute of Standards and Technology [NIST], 2001).
2-3.5 Grinding
As shown in Fig. 2-7, the finished cement is produced by grinding the clinker with calcium sulfate, usually gypsum (\(\text{CS}_2\text{H}_2\)) which, for reasons that will be explained later, prevents a phenomenon known as flash set. Most clinker is ground in tubular mills partly filled with hard steel balls and, depending upon the type of cement being manufactured, the clinker is ground to a given fineness (Appendix B). The particle size of the cement grains varies from 1 to 100 µm.

The ball milling process is inherently inefficient, with 97–99% of the energy input being converted to heat. Consequently, it is necessary to continuously cool the mill. If the cement reaches an excessively high temperature, too much of the gypsum can dehydrate, forming calcium sulfate hemihydrate (\(\text{CS}_2\text{H}_{1/2}\)). While still able to prevent flash set, dehydrated calcium sulfate compounds can cause another phenomenon called false set, which will also be discussed later in this chapter.

Grinding aids are prohibited during the production of well cements. Such compounds can interfere with additives used to control the performance of well cement slurries.

2-3.6 Storage
Portland cement is a moisture-sensitive material. If kept dry, it will retain its quality indefinitely. Cement stored in contact with damp air or moisture sets more slowly and develops less strength. At the cement plant, bulk cement is stored in large silos. The relative humidity in a warehouse used to store bagged cement should be as low as possible. Frequently, there are several silos for a particular type of cement. In such cases, cement from different silos can be blended to maintain a more consistent product.

2-4 Hydration of the clinker phases
The compounds present in Portland cement are anhydrous. When brought into contact with water, they are attacked or decomposed, forming hydrated compounds. Supersaturated and unstable solutions form, gradually depositing their excess solids. Because the solubilities of the original anhydrous compounds are much higher than those of the hydration products, complete hydration should ultimately occur.

Research concerning cement hydration has largely consisted of studying the behavior of individual clinker phases in an aqueous environment and relating the findings to the behavior of the multicomponent system Portland cement. The principal components of Portland cement (\(\text{C}_3\text{S}, \text{C}_2\text{S}, \text{C}_3\text{A},\) and \(\text{C}_4\text{AF}\)) display different hydration kinetics and form different hydration products. This chapter follows the same path, first presenting the contributions of the individual phases in this section and finally discussing their combined performance in Portland cement in the following section.

2-4.1 Hydration of the silicate phases
The silicate phases in Portland cement are the most abundant, often comprising more than 80% of the total material. \(\text{C}_3\text{S}\) is the principal constituent, with a concentration as high as 68%. The quantity of \(\text{C}_2\text{S}\) normally does not exceed 30%.

As shown in the idealized chemical equations below, the hydration products for both phases are calcium silicate hydrate and calcium hydroxide (also known as portlandite).

\[
\begin{align*}
2\text{C}_3\text{S} & \rightarrow \text{C}_3\text{S}_2\text{H}_3 + 3\text{CH} \quad (2-1) \\
2\text{C}_2\text{S} + 4\text{H} & \rightarrow \text{C}_3\text{S}_2\text{H}_3 + \text{CH} \quad (2-2)
\end{align*}
\]
The calcium silicate hydrate does not have the exact composition of C₃S₂H₃; instead, the C:S and H:S ratios are variable depending upon such factors as the calcium concentration in the aqueous phase (Barret et al., 1980a and 1980b), temperature (Odler and Skalny, 1973), the presence of additives (Odler and Skalny, 1971), and aging (Barnes, 1983). The material is quasi-amorphous, and it is therefore commonly called “C-S-H phase.” The C-S-H phase comprises roughly 65% of fully hydrated Portland cement at ambient conditions and is considered the principal binder of hardened cement. By contrast, the calcium hydroxide is highly crystalline and occurs as hexagonal plates. Its concentration in hardened cement is usually between 15% and 20%.

After a brisk but brief initial hydration when added to water, the silicate phases experience a period of low reactivity, called the “induction period.” During this stage, they do not significantly influence the rheology of the cement slurry. Substantial hydration eventually resumes and, as shown in Fig. 2-8, the hydration rate of C₃S exceeds that of C₂S by a wide margin. Because of the C₃S abundance, and the massive formation of C-S-H phase, the hydration of C₃S is largely responsible for the beginning of the set and early strength development. The hydration of C₂S is significant only in terms of the final strength of the hardened cement.

The mechanism of C₂S hydration is very similar to that of C₃S; however, the process occurs more slowly. The C-S-H phase formed by the hydration of C₂S is also very similar to that formed by C₃S. Therefore, only C₃S is considered in this chapter. The hydration of C₂S is sometimes considered to be an analog for the hydration behavior of Portland cement.

The hydration of C₃S is an exothermic process; therefore, the hydration rate can be followed by conduction calorimetry. From the thermogram given in Fig. 2-9, five hydration stages are arbitrarily defined:

I. Preinduction period
II. Induction period
III. Acceleration period
IV. Deceleration period
V. Diffusion period

**Fig. 2-8.** Hydration of C₂S and C₃S versus time.

**Fig. 2-9.** Schematic representation of changes taking place in C₃S-water system.
2-4.1.1 Preinduction period

The preinduction period begins during mixing and lasts only a few minutes immediately following mixing. Upon contact with water, a fast hydration reaction begins between C₃S and the mix water. A large exotherm is observed at this time, resulting from the wetting of the powder and the rapidity of the initial hydration.

The first step of this reaction appears to be a protonolysis of the silicate and oxygen ions at the C₃S surface, followed by a congruent dissolution of the material (Barret et al., 1983; Barret, 1986; Damidot et al., 1992). The O²⁻ ions originally present in the C₃S lattice enter the liquid phase as OH⁻ ions, and the SiO₄⁴⁻ ions hydrolyze and form dissociated silicic acid. The balancing positive charges are from Ca²⁺ ions (Eq. 2-3).

\[
2\text{Ca}_3\text{SiO}_5 + 8\text{H}_2\text{O} \rightarrow 6\text{Ca}^{2+} + 10\text{OH}^- + 2\text{H}_2\text{SiO}_4^- \quad (2-3)
\]

During the preinduction period, C₃S dissolution is faster than the diffusion of the reaction products away from the surface. As a result, the liquid phase surrounding the C₃S surface becomes supersaturated, and a layer of C-S-H phase begins to precipitate on the surface (Menetrier, 1977; Barret and Bertandrie, 1986).

\[
2\text{Ca}^{2+} + 2\text{OH}^- + 2\text{H}_2\text{SiO}_4^- \rightarrow \text{Ca}_2\left(\text{OH}\right)_2\text{H}_4\text{Si}_2\text{O}_7 + \text{H}_2\text{O} \quad (2-4)
\]

Equation 2-4 assumes that the initial C-S-H phase has a C:S ratio of about 1.0 (Menetrier, 1977). In addition, the silicate anions in the C-S-H phase are, at short hydration times, dimeric (Michaux et al., 1983).

Addition of Eqs. 2-3 and 2-4 produces the following.

\[
2\text{Ca}_3\text{SiO}_5 + 7\text{H}_2\text{O} \rightarrow \text{Ca}_2\left(\text{OH}\right)_2\text{H}_4\text{Si}_2\text{O}_7 + 4\text{Ca}^{2+} + 8\text{OH}^- \quad (2-5)
\]

During the preinduction period, critical supersaturation with respect to calcium hydroxide does not occur; therefore, as indicated in Equation 2-5, the concentration of lime increases as hydration continues.

According to another theory, the initial dissolution of C₃S is incongruent. A SiO₂-rich layer is formed at the surface that subsequently adsorbs Ca²⁺ ions dissolved in the liquid phase. Thus, an electrical double layer forms at the C₃S surface (Tadros et al., 1976; Skalny and Young, 1980).

2-4.1.2 Induction period

As explained earlier, relatively little hydration activity is observed during the induction period. The rate of heat liberation dramatically falls. Additional C-S-H phase precipitates slowly, and the Ca²⁺ and OH⁻ concentrations continue to rise. When critical supersaturation finally occurs, precipitation of calcium hydroxide begins. Hydration resumes at a significant rate, signaling the end of the induction period. At ambient temperatures, the duration of the induction period is a few hours.

The mechanism of the induction period is still a subject of debate among cement chemists. Several theories have been proposed; however, they are often more complementary than contradictory. They are summarized in Table 2-4.

2-4.1.2.1 Impermeable hydrate layer theory

The impermeable hydrate layer theory postulates that the “first-stage” product precipitated at the C₃S surface acts as a barrier that inhibits the migration of water to the unhydrated surface, the release of Ca²⁺, OH⁻, and silicate ions into the liquid phase, or both (Brown et al., 1984; Skalny and Young, 1980). As a result, the initial fast hydration slows and is followed by a period in which the reaction barely progresses. Toward the end of this dormant period, the initial C-S-H layer becomes more permeable, and the hydration rate accelerates.

There are three principal theories to explain why the C-S-H layer becomes more permeable. According to de Jong et al. (1967), the C-S-H layer ages and undergoes a morphological change, resulting in increased permeability. Consequently, water more easily penetrates the layer, and hydration continues. Another theory holds that osmotic pressure is generated between the C-S-H layer and the unhydrated C₃S surface (Powers, 1961; Double et al., 1978; Birchall et al., 1980). The gel layer eventually bursts, exposing the unhydrated surface. A vigorous release of hydration products then occurs, resulting in a massive formation of C-S-H phase. The third proposed mechanism involves the breakdown of the C-S-H layer because of water imbibition (Dent-Glasser, 1979).
2-4.1.2.2 Electrical double-layer theory

As mentioned earlier, the electrical double-layer theory assumes that the initial hydration of C3S is incongruent. An SiO2-rich layer, with adsorbed Ca2+ ions, creates an electrical double layer that impedes the passage of additional ions into solution. Therefore, the induction period ensues (Tadros et al., 1976; Skalny and Young, 1980). The double layer gradually breaks down, and the hydration rate accelerates.

2-4.1.2.3 Nucleation of Ca(OH)2 theory

The liberation of Ca(OH)2 always accompanies the hydration of C3S. Initially, the Ca(OH)2 dissolves in the liquid phase. As hydration continues, the Ca(OH)2 does not precipitate even when its liquid-phase concentration reaches or exceeds saturation. According to the nucleation of Ca(OH)2 theory, the surfaces of the Ca(OH)2 nuclei are poisoned by adsorbed silicate ions, preventing precipitation (Tadros et al., 1976; Wu and Young, 1984). Owing to the supersaturation of Ca(OH)2 in the liquid phase, further hydration of C3S is retarded (Odler and Dorr, 1979).

Eventually, sufficient supersaturation (~1.5 to 2.0 times the saturation value) occurs to form stable nuclei, and precipitation of solid Ca(OH)2 commences. At this stage the crystalline Ca(OH)2 begins to act as a sink for Ca2+ ions, enabling renewed intense C-S-H formation.

2-4.1.2.4 Nucleation of C-S-H theory

According to the nucleation of C-S-H theory, the nucleation and growth of a “second-stage” C-S-H controls the end of the induction period. The second-stage C-S-H is different from the initial, “first-stage” C-S-H formed during the preinduction period. In agreement with the nucleation of Ca(OH)2 theory, formation of first-stage C-S-H is controlled by the Ca(OH)2 concentration in the liquid phase. However, unlike the impermeable hydrate layer theory, the first-stage C-S-H does not act as a barrier layer and does not inhibit hydration.

During the induction period, C-S-H nuclei begin to form. When the concentration and size of the nuclei reach a critical level, fast production of second-stage C-S-H begins (Odler and Dorr, 1979; Barret and Bertrandie, 1986). At the same time, solid Ca(OH)2 begins to precipitate.

2-4.1.3 Acceleration and deceleration periods

At the end of the induction period, only a small percentage of the C3S has hydrated. The acceleration and deceleration periods, also collectively known as the “setting period,” represent the interval of most rapid hydration. During the acceleration period, solid Ca(OH)2 crystallizes from solution and the C-S-H phase deposits into the available water-filled space. The hydrates intergrow, a cohesive network is formed, and the system begins to develop strength.

### Table 2-4. Theories on the Mechanism of C3S Hydration

<table>
<thead>
<tr>
<th>Mechanism</th>
<th>Impermeable Hydrate</th>
<th>Electrical Double-</th>
<th>Nucleation of</th>
<th>Nucleation of</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pre-induction period</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Beginning of</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>induction period</td>
<td>First-stage product acts as diffusion barrier</td>
<td>Electrical double layer forms and impedes passage of ions</td>
<td>Supersaturation of liquid phase with respect to CH stops further rapid dissolution of C3S</td>
<td></td>
</tr>
<tr>
<td>Changes during</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>induction period</td>
<td>Phase transformation or aging of C-S-H layer</td>
<td>Osmotic pressure phenomena across the first-stage product layer</td>
<td>Gradual weakening of double layer</td>
<td>Slow nucleation of CH</td>
</tr>
<tr>
<td>End of induction period</td>
<td>Increased permeability of C-S-H layer</td>
<td>Breakdown of C-S-H layer due to osmotic pressure and/or imbibition</td>
<td>Breakdown of double layer</td>
<td>CH nuclei reach critical size</td>
</tr>
<tr>
<td>Acceleratory period</td>
<td></td>
<td></td>
<td></td>
<td>Accelerated dissolution of C3S, growth of second-stage C-S-H and CH</td>
</tr>
</tbody>
</table>

† From Hewlett, 2001. Reprinted with permission from Elsevier.
The porosity of the system decreases as a consequence of hydrate deposition. Eventually, hydrate deposition hinders the transportation of ionic species and water through the network of C-S-H phase, and the hydration rate decelerates. At ambient conditions, these events occur within several days.

2-4.1.4 Diffusion period

Hydration continues at a slow pace owing to the ever-decreasing system porosity. The network of hydrated products becomes more and more dense, and strength increases. There is no evidence of major structural changes; however, polymerization of C-S-H phase has been observed (Dent-Glasser et al., 1978). The duration of the diffusion period is indefinite at ambient conditions. Portlandite crystals continue to grow and engulf the hydrating C3S grains; as a result, total hydration is never attained (Fig. 2-10).

2-4.2 Hydration of the aluminate phases

As shown in Fig. 2-11, the aluminate phases, especially C3A, are the most reactive at short hydration times. Although they are present in considerably less abundance than the silicates, they have a significant influence on the rheological properties of the cement slurry and early strength development of the set cement. During the hydration of Portland cement, the aluminate phases react with the added calcium sulfate. Thus the reactions in the system C3A–C3S–H2O and C4AF–C3S–H2O are of particular importance.
2-4.2.1 Tricalcium aluminate

In the absence of calcium sulfate, the first hydration step is analogous to that of C3S—an interfacial reaction between the surface of the anhydrous solid and water. This irreversible reaction leads to the hydroxylation of the superficial anions AlO2– and O2– into [Al(OH)4]– and OH– anions (Bertrandie and Barret, 1986), resulting in a congruent dissolution of the protonated surface.

\[
\text{Ca}_3\text{Al}_2\text{O}_6 + 6\text{H}_2\text{O} \rightarrow 3\text{Ca}^{2+} + 2\left[\text{Al(OH)}_4\right]^- + 6\text{OH}^- \quad (2-6)
\]

The solution quickly becomes supersaturated with respect to some calcium aluminate hydrates, leading to their precipitation.

\[
6\text{Ca}^{2+} + 4\left[\text{Al(OH)}_4\right]^- + 2\text{OH}^- + 15\text{H}_2\text{O} \rightarrow
\text{Ca}_2\left[\text{Al(OH)}_6\right]_2 \cdot 3\text{H}_2\text{O} + \left[2\text{Ca}_2\text{Al(OH)}_7 \cdot 6\text{H}_2\text{O}\right] \quad (2-7)
\]

By adding Eqs. 2-6 and 2-7, the following equation is obtained using cement-chemistry notation.

\[
2\text{C}_3\text{A} + 27\text{H} \rightarrow \text{C}_2\text{AH}_8 + \text{C}_4\text{AH}_{19} \quad (2-8)
\]

The calcium aluminate hydrates in Eq. 2-8 are metastable and occur as hexagonal crystals. They eventually convert to the more stable cubic form, C3AH6, as shown below. At ambient conditions, this reaction occurs within several days (Tumidajski and Thomson, 1994).

\[
\text{C}_2\text{AH}_8 + \text{C}_4\text{AH}_{19} \rightarrow 2\text{C}_3\text{AH}_6 + 15\text{H} \quad (2-9)
\]

As shown in Fig. 2-12, C3A hydration does not have an induction period. If uncontrolled hydration were allowed to occur in a Portland cement slurry, severe rheological difficulties would arise.

\[
\text{C}_3\text{A} \text{ hydration is controlled by the addition of } 3 \text{ to } 5\% \text{ gypsum to the cement clinker before grinding, as described earlier in this chapter. Upon contact with water, part of the gypsum dissolves. The calcium and sulfate ions released in solution react with the aluminate and hydroxyl ions released by the C3A to form a calcium trisulfoaluminate hydrate, known as the mineral ettringite (Collepardi et al., 1978). In Portland cements, iron can substitute for aluminum in the ettringite structure. In such cases, iron substituted ettringite is frequently called an AFt (aluminoferrite trisulfate) phase.}
\]

\[
6\text{Ca}^{2+} + 2\left[\text{Al(OH)}_4\right]^- + 3\text{SO}_4^{2-} + 4\text{OH}^- + 26\text{H}_2\text{O} \rightarrow
\text{Ca}_6\left[\text{Al(OH)}_6\right]_2(\text{SO}_4)_3 \cdot 26\text{H}_2\text{O} \quad (2-10)
\]

The global reaction can be written as

\[
\text{C}_3\text{A} + 3\text{C}_3\text{S}_2\text{H} + 26\text{H} \rightarrow \text{C}_3\text{A} \cdot 3\text{C}_3\text{S} \cdot 32\text{H}. \quad (2-11)
\]

As shown in Fig. 2-13, ettringite occurs as needle-shaped crystals that precipitate onto the C3A surfaces, hindering further rapid hydration. Thus, as shown in Fig. 2-14, an induction period is artificially created. During this period, the gypsum is gradually consumed and ettringite continues to precipitate. When the supply of gypsum is exhausted, the sulfate-ion concentration sharply drops. Ettringite becomes unstable and converts to a platy calcium monosulfoaluminate hydrate. If iron is present in the structure, the compound is known as an AFm (aluminoferrite monosulfate) phase. The protective sulfoaluminate layer breaks down and rapid hydration resumes (Collepardi et al., 1978).

\[
\text{C}_3\text{A} + 3\text{C}_3\text{S}_2\text{H} \cdot 32\text{H} \rightarrow \text{C}_3\text{A} \cdot 3\text{C}_3\text{S} \cdot 12\text{H} \quad (2-12)
\]

Any remaining unhydrated C3A forms calcium aluminate hydrate as shown in Eq. 2-8 (Bensted, 1976).
2-4.2.2 Calcium aluminoferrite

Calcium aluminoferrite is classically referred to as C₄AF or brownmillerite. However, the actual composition of calcium aluminoferrite is a solid solution with the general formula \( \text{Ca}_4\text{Fe}(2-x)\text{Al}_x\text{O}_{10} \), where \( x \) varies from 0 to 1.4. C₄AF is one point in the series in which \( x = 1.0 \). Many cements have a ferrite phase with a composition close to C₄AF; therefore, this is the most common composition studied.

Under comparable conditions, the hydration products formed in the hydration of the ferrite phases are similar in many respects to those formed from C₃A, although the rates of reaction differ (Ramachandran and Beaudoin, 1980). As shown in Fig. 2-11, C₄AF has the fastest hydration rate of all the pure clinker phases (Brown, 1993). However, the reactivity of the ferrite phase generally declines with increasing Fe content (Collepardi et al., 1979).

In the absence of gypsum, the course of ferrite-phase hydration is similar to that of C₃A. The metastable iron-substituted AFm phases \( \text{C}_4(\text{A,F})\text{H}_{19} \) and \( \text{C}_2(\text{A,F})\text{H}_8 \) form, which eventually convert to a hydrogarnet phase, \( \text{C}_3(\text{A,F})\text{H}_6 \). At elevated temperatures, the hydrogarnet phase is formed directly.

In the presence of gypsum, the rates of reaction of C₄AF are higher, and an AFt phase forms that is similar to ettringite (Bensted, 2001; Meller et al., 2004). Like ettringite, the ferrite AFt phase eventually converts to an AFm phase (Tong and Yang, 1994).

2-5 Hydration of Portland cements—The multicomponent system

The hydration of Portland cement is a sequence of overlapping chemical reactions between clinker components, calcium sulfate, and water, leading to continuous cement-slurry thickening and hardening. Although the hydration of C₃S is often used as a model for the hydration of Portland cement, it must be kept in mind that many additional parameters are involved.

From a chemical point of view, Portland cement hydration is a complex dissolution and precipitation process in which, unlike the hydration of the individual pure phases, the various hydration reactions proceed simultaneously at differing rates. The phases also influence each other. For example, the hydration of C₃A is modified by the presence of hydrating C₃S, because the production of calcium hydroxide reinforces the retarding action of gypsum. None of the clinker minerals is pure. Depending upon the composition of the raw materials, each contains alien oxides in solid solution that alter their reactivity.
The hydration products are also impure. The C-S-H phase incorporates significant amounts of aluminum, iron, and sulfur, while the ettringite and monosulfoaluminate phases contain silicon. The calcium hydroxide also contains small quantities of foreign ions, chiefly silicate.

A typical schematic thermogram of Portland cement hydration is shown in Fig. 2-15. It can roughly be described as the addition of the thermograms for C₃S and C₃A, adjusted for relative concentration.

2-5.1 Volume changes during setting

When Portland cements react with water, the system cement plus water undergoes a net volume diminution. This is an absolute volume decrease. It occurs because the absolute density of the hydrated material is greater than that of the initial reactants. Table 2-5 shows the change of absolute volume with time for a number of Portland cements.

Despite the decrease in absolute volume, the external dimensions of the set cement, or the bulk volume, remain the same or slightly increase. To accomplish this, the internal porosity of the system increases.

In the confined environment of a wellbore, the decrease in absolute volume can affect the transmission of hydrostatic pressure to the formation and can affect the cement’s ability to prevent annular fluid migration. This subject is thoroughly discussed in Chapter 9.

2-5.2 Effect of temperature

Temperature is one of the major factors affecting the hydration of Portland cement. The hydration rate of the cement and the nature, stability, and morphology of the hydration products are strongly dependent upon this parameter.

Elevated hydration temperatures accelerate the hydration of cement. As illustrated by the calorimetry curves in Fig. 2-16, the duration of the induction and setting periods is shortened, and the rate of hydration during the setting period is much higher. However, upon extended curing, the degree of hydration and the ultimate strength are often reduced. This is most probably related to the formation of a dense layer of C-S-H phase around the C₃S surfaces, hindering their complete hydration (Bentur et al., 1979).

Up to 104°F [40°C], the hydration products are the same as those that occur at ambient conditions. Certain changes occur in the microstructure and morphology of C-S-H phase at higher temperatures. The material becomes more fibrous, and a higher degree of silicate polymerization is observed. At curing temperatures...
exceeding 230°F [110°C], the C-S-H phase is no longer stable, and crystalline calcium silicate hydrates eventually form. This subject is thoroughly discussed in Chapter 10.

The conversion of the hexagonal aluminate hydrates to the cubic form (Eq. 2-9) is strongly accelerated by temperature. Above 176°F [80°C], C₃AH₆ is directly formed.

The behavior of the calcium sulfoaluminates also depends on curing temperature. Above 140°F [60°C], ettringite is no longer stable and decomposes to calcium monosulfoaluminate and gypsum (Barvinok et al., 1976).

\[
\text{C}_3\text{A} \cdot 3\text{CS} \cdot 32\text{H} \rightarrow \text{C}_3\text{A} \cdot \text{CS} \cdot 12\text{H} + 2\text{CSH}_2 + 16\text{H} \quad (2-13)
\]

However, other researchers have recorded higher stability limits for ettringite, up to 230°F [110°C] (Lach and Bures, 1976). Calcium monosulfoaluminate is reported to be stable up to 374°F [190°C] (Satava and Veprek, 1975).

### 2-5.3 Flash set and false set

When Portland cement clinker is ground alone (i.e., without calcium sulfates) and mixed with water, the C₃A and C₄AF rapidly react, the slurry temperature markedly increases, and an irreversible stiffening occurs, followed quickly by a pseudoset. This phenomenon is called a “flash set,” or sometimes a “quick set.” In the context of well cementing, a flash set could prevent proper placement of the cement slurry in the annulus.

To avoid uncontrolled C₃A and C₄AF hydration, calcium sulfates (usually gypsum) are ground in with the clinker during the manufacture of Portland cement. For optimal cement performance, the quantity of calcium sulfates must be balanced according to the reactivity of the clinker (Fig. 2-17).

A flash set can still occur if the quantity of calcium sulfates in the cement is insufficient with respect to the reactivity of the clinker. Unfortunately, no simple rule exists to determine the optimal calcium-sulfates content, because this depends upon a variety of parameters, including cement particle-size distribution, calcium-sulfates reactivity, alkali content, and aluminate-phase content (Lerch, 1946; Ost, 1974).

Because of the heat generated during the grinding process at the cement mill, the gypsum added as calcium sulfate in Portland cement is dehydrated to a variable extent. In some cases, calcium sulfate hemihydrate (CSH₁₂) is the only form of calcium sulfate present. At ambient temperature, the solubility of CSH₁₂ is approximately three times that of gypsum; therefore, upon hydration, the aqueous phase of the cement slurry quickly becomes supersaturated with respect to gypsum.

To relieve this condition, so-called “secondary gypsum” is precipitated. A marked stiffening or gelation of the cement slurry, known as “false set,” is observed (Fig. 2-17).

False sets are reversible by vigorous slurry agitation; however, such agitation would not be possible during most well cementing operations, particularly if the slurry is mixed continuously. The addition of a dispersant reduces the rheological impact of false sets (Chapter 3).

### 2-5.4 Effects of aging

The performance of Portland cement can be affected significantly by exposure to the atmosphere and/or high temperatures during storage in sacks or silos. The principal effects upon neat cement slurries (no additives) include the following (Silk, 1986).

- Increased thickening time
- Decreased compressive strength
- Decreased heat of hydration
- Increased slurry viscosity
The effects are principally caused by carbonation of the calcium silicate hydrate phases and partial hydration of the free CaO and C\textsubscript{3}A/C\textsubscript{4}AF. The rate at which these processes occur is directly related to the relative humidity of the storage environment. The effects of limited cement exposure to air during transport operations have been shown to be less severe (Cobb and Pace, 1985).

The water liberated during this reaction can prehydrate the aluminate, silicate, and alkali phases. When the cement is eventually hydrated in water, an imbalance exists between the aluminates and sulfates, often leading to a false set. This reaction also causes the cement to clump, hindering transport between containers.

When Portland cement is stored in hot regions, the temperature in the silo can be sufficiently high to dehydrate the gypsum (Locher \textit{et al.}, 1980). Such cements would be more apt to exhibit the false-set phenomenon. Adding hot cement (more than 200°F [93°C]) to the silo can have a similar effect. Thus, when designing cement systems for a particular job, it is always prudent to perform the laboratory tests with samples of the cement to be used at the wellsite.

2-5.5 Influence of alkalis

The principal alkaline elements found in Portland cement are sodium and potassium. They affect setting and strength development; thus, the amounts of these substances are usually held below 1\% (expressed as oxides). In well cements the maximum concentration of total alkalis is 0.75\% (as a convention, these are expressed as total equivalent Na\textsubscript{2}O). Total alkalis are the sum of insoluble alkalis (impurities in the lattices of clinker phases) and soluble alkalis (in the form of alkali sulfates).

The effects of alkalis upon strength development are unpredictable. Alkalis have been shown to improve compressive strength (Sudakas \textit{et al.}, 1978) and to be deleterious. Jawed and Skalny (1978) demonstrated a positive effect upon early strength but a negative effect upon long-term strength.

If sufficient potassium sulfate is present as an impurity in the cement, a reaction with gypsum can occur, resulting in the formation of syngenite.

\[
2\text{CaSO}_4 \cdot 2\text{H}_2\text{O} + \text{K}_2\text{SO}_4 \rightarrow \\
\text{CaK}_2\left(\text{SO}_4\right)_2 \cdot \text{H}_2\text{O} + \text{CaSO}_4 \cdot \frac{1}{2}\text{H}_2\text{O} + 2.5\text{H}_2\text{O} \\
\text{syngenite}
\]  

(2-14)

2-5.6 Influence of surface area

The surface area (sometimes called fineness) is an important parameter with respect to cement reactivity and slurry rheology. The fineness of cement is usually determined by measuring the air permeability of a small layer of lightly compacted cement (Blaine method) (Appendix B). With the assumption that the cement particles are spherical, such information is used to calculate a theoretical surface area; however, this method underestimates the true surface area (Vidick \textit{et al.}, 1987), as measured by the Brunauer-Emmett-Teller (BET) gas-adsorption method (Table 2-6).

<table>
<thead>
<tr>
<th>Sample</th>
<th>Surface Area (m\textsuperscript{2}/g)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Blaine</td>
<td>BET</td>
</tr>
<tr>
<td>A</td>
<td>0.2</td>
</tr>
<tr>
<td>B</td>
<td>0.3</td>
</tr>
<tr>
<td>C</td>
<td>0.4</td>
</tr>
</tbody>
</table>

† From Vidick \textit{et al.}, 1987. Reprinted with permission from Elsevier.

The water-to-cement ratio required to wet the cement particles and prepare a pumpable slurry is directly related to the surface area (Sprung \textit{et al.}, 1985). Thus, for consistency of performance, the fineness is controlled by the cement manufacturer.

The development of compressive strength is often correlated with the cement's surface area (Bakchoutov \textit{et al.}, 1980, and Frigione and Marra, 1976). Generally, the results indicate that cements with high fineness tend to develop greater compressive strength. Some research shows that the rate of hydration is accelerated by high surface area, but that it is difficult to separate the effects of fineness from those of chemical composition. Hunt (1986) and Hunt and Elspass (1986), working with a selection of well cements, found a good correlation between Blaine fineness and thickening time (Fig. 2-18).
2-5.7 Sulfate resistance

Downhole brines commonly contain magnesium sulfate and sodium sulfate, and detrimental effects can result when such solutions react with certain cement hydration products. These sulfates react with precipitated calcium hydroxide to form magnesium hydroxide and sodium hydroxide as well as calcium sulfate. The calcium sulfate can in turn react with the aluminates to form secondary ettringite.

$$\text{Ca(OH)}_2 + \text{MgSO}_4 \rightarrow \text{CaSO}_4 \cdot 2\text{H}_2\text{O} + \text{Mg(OH)}_2$$

Swelling occurs because of the replacement of Ca(OH)$_2$ by Mg(OH)$_2$.

$$\text{Ca(OH)}_2 + \text{Na}_2\text{SO}_4 + 2\text{H}_2\text{O} \rightarrow \text{CaSO}_4 \cdot 2\text{H}_2\text{O} + 2\text{NaOH}$$

An increase in cement porosity occurs, because NaOH is much more soluble than Ca(OH)$_2$.

$$3\text{CaO} \cdot \text{Al}_2\text{O}_3 \cdot 6\text{H}_2\text{O} + 3(\text{CaSO}_4 \cdot 2\text{H}_2\text{O}) + 20\text{H}_2\text{O} \rightarrow 3\text{CaO} \cdot \text{Al}_2\text{O}_3 \cdot 3\text{CaSO}_4 \cdot 32\text{H}_2\text{O}$$

or

$$\text{C}_3\text{AH}_6 + 3\text{CSH}_2 + 20\text{H} \rightarrow \text{C}_3\text{A} \cdot 3\text{C}_3\text{S} \cdot 32\text{H}$$

When ettringite forms after the cement has developed strength, an expansion occurs. As discussed in Chapter 7, a limited amount of expansion can be beneficial in terms of bonding; however, uncontrolled cement expansion leads to loss of compressive strength, cracking, and damage to tubulars.

Portland cements with low C$_3$A contents are less susceptible to sulfate attack after setting (American Petroleum Institute [API], 1955). In addition, because the solubility of magnesium sulfate and sodium sulfate is low above 140°F [60°C], sulfate attack is not normally a serious problem at that temperature or higher (Suman and Ellis, 1977). In any event, as discussed in Chapter 3, sulfate attack can be substantially reduced by the addition of pozzolanic materials such as fly ash to the cement system.

### 2-6 Advanced techniques for monitoring and modeling cement hydration

The previous discussion showed that Portland cement is mineralogically complicated, and the hydration chemistry is not sufficiently understood. This obscurity is partially a result of the lack of scientific techniques for directly observing the chemical changes that occur in cement slurries over the early minutes and hours after mixing.

During the 1990s materials scientists began to apply some advanced analytical techniques toward acquiring a better understanding of cement hydration (Luke et al., 1995). Such techniques included:

- environmental scanning electron microscopy (Mehta et al., 1994)
- Fourier transform infrared (FTIR) spectroscopy (Hughes et al., 1994a and 1994b; Fletcher et al., 1995)
- nuclear magnetic resonance spectroscopy (Skibsted et al., 1993; Brough et al., 1994)
- electron energy loss spectroscopy (Byrdson et al., 1994)
- synchrotron energy dispersive X-ray diffraction (XRD) (Kuzel and Pöllmann, 1991; Meller et al., 2004).

These experimental approaches are complemented by a variety of modeling methods (Bentz et al., 1994). This work has brought the study of Portland cement into the mainstream of materials science.

For well cementing, such methods have the potential to open a window on the chemical changes that occur in cement slurries from just seconds after mixing throughout the life of the well. As work continues to further the understanding of cement hydration, fine-tuning of slurry design and, most importantly, improving the reliability of cement jobs may be possible. Some notable studies are highlighted below.
2-6.1 FTIR spectroscopy

FTIR spectroscopy has long been used for the qualitative identification of minerals. Until recently, the applications for Portland cement were limited to characterizing the main clinker phases. Furthermore, sensitivity was relatively low for the accessory minerals (such as sulfates) that strongly influence the properties of commercial cements. During the 1990s, important advances in spectrometer design and chemometric signal processing brought radical changes to FTIR analysis.

Hughes et al. (1994a) showed that diffuse reflectance FTIR spectroscopy allowed highly reproducible cement spectra to be obtained. Sensitivity to the accessory minerals was also vastly improved. Using attenuated total reflectance optics, Hughes et al. (1994b) extended the method to explore hydration chemistry.

The spectral absorption bands that reveal the chemistry of cement hydration lie in four distinct regions of the midinfrared spectrum. These are the Si-O stretching modes around 600–1,000 cm⁻¹; the S-O modes around 800–1,200 cm⁻¹; the H-O-H bending modes associated with free water at about 1,635 cm⁻¹; and the broad and complex band at 3,400–3,600 cm⁻¹ that arises from O-H stretching vibrations both in water and OH-containing minerals. Figure 2-19 shows the evolution of the mid-infrared spectrum of a neat Class G cement slurry at 300°F [150°C] and 2,000 psi [14 MPa]. Hydration was monitored for 7 hr.

The rather amorphous C-S-H phase formed at lower temperatures progressively gives way to distinct crystalline hydrates. This is shown very clearly in Fig. 2-19, in which the band at 943 cm⁻¹ is replaced by strong and well-defined bands at 972, 928, and 855 cm⁻¹. These are identified as α-C₂SH, a common phase that can form in well cements exposed to high temperatures (Chapter 10). The spectra also show changes in the sulfate bands. The strong AFT band (at 1,110 cm⁻¹), formed during mixing, broadens and weakens with time to form a shoulder around 111 cm⁻¹.

The performance of Portland cements that meet the requirements for a given API or International Organization for Standardization (ISO) class (Section 2-7) is highly variable, especially when cement additives such as retarders are present in the slurry (Chapter 3). Therefore, prejob performance testing of a given cement-slurry formulation is essential to prevent operational difficulties. To reduce the testing requirements, Fletcher et al. (1995) showed that the FTIR spectrum of a cement yields information about the factors that control hydration and performance variability. In essence, the FTIR spectrum provides a “signature” of cement composition and performance (Fig. 2-20). Statistical models, based on linear statistics and artificial neural networks, allow prediction of cement composition, extent of aging, and particle-size distribution. Case studies have demonstrated that the spectra have useful predictive value, particularly in identifying anomalous or “rogue” cements that can be expected to perform very differently than normal. Despite the promise of this technique, FTIR spectrometers are not yet common in oilfield laboratories in which cement-slurry design is performed, and the method has not been widely developed.

Fig. 2-19. FTIR-attenuated total reflectance spectra of a Class G well cement slurry at 300°F [150°C] and 2,000 psi [14 MPa]. Spectra are shown at intervals of 38 min, extending over 7 hr from mixing. Successive spectra are offset upwards by 0.02 absorbance units.

Fig. 2-20. Typical FTIR spectrum of Portland cement (from Fletcher et al., 1995). Reprinted with permission of SPE.
2-6.2 XRD techniques

Powder XRD methods have been widely used by cement chemists for mineralogical analysis of clinkers, anhydrous cements, and individual cement minerals, including hydrates. Such techniques are routinely used to determine the “potential phase composition” of Portland cements (Section 2-7), one of the criteria used for cement classification.

Kuzel and Pöllman (1991) demonstrated that, using a wet cell, XRD techniques could be applied toward monitoring cement hydration. They used a time-lapse technique to track tricalcium aluminate reactions as they occurred during cement hydration. This technique requires rapid data acquisition to follow the reactions with sufficient detail; therefore, they used an intense synchrotron X-ray source combined with energy-dispersive detectors. A sample result (Fig. 2-21) shows the gradual development of portlandite and ettringite, created as $\text{C}_3\text{A}$ reacts with gypsum. When all the gypsum is consumed after about 60 hr, it seems to trigger the transformation of ettringite ($\text{AF}_t$) to monosulfate ($\text{AF}_m$).

Also using synchrotron energy dispersive XRD, Meller et al. (2004) followed the hydration of the ferrite phase at various temperatures, with and without gypsum. The results without gypsum are shown in Fig. 2-22. The spectra on the top illustrate the mineralogical changes over a 2-hr period. The evolution of $\text{C}_4\text{AF}$ to the metastable $\text{AF}_m$ phases and the hydrogarnet phase is clear. Twenty-four patterns were collected, one every 5 min.

When gypsum is added to $\text{C}_4\text{AF}$ at 86°F [30°C], ettringite is observed to form within 6 min of contact with water (Fig. 2-23). Ettringite increases throughout the 3-hr observation time, and both the $\text{C}_4\text{AF}$ and gypsum decrease.

Fig. 2-21. Tracking aluminate reactions in hydrating cement using time-lapse XRD.

Fig. 2-22. Hydration of $\text{C}_4\text{AF}$ at 30 and 100°C (from Meller et al., 2004). Key: $\times = \text{C}_4\text{AF}; + = \text{C}_2\text{AH}_8/\text{C}_4\text{AH}_{19}; o = \text{C}_2\text{AH}_6$. Reproduced by permission of the Royal Society of Chemistry.
Using computer modeling techniques, Garboczi and Bentz (1991) simulated all of the steps in Portland cement hydration. The simulation can be either three-dimensional, in which cement particles are modeled as spheres, or two-dimensional, in which each particle can be given an individual shape based on an electron photomicrograph of a cement sample. Particle-size distribution can be varied at will, but generally the mean particle diameter is 15–30 μm. The cement particles include ground clinker and added gypsum. A simulation limited to the silicate phases is illustrated in Fig. 2-24.

Some time later in 2, the green diffusing particles turn into C-S-H gel (also yellow) when they either return to a cement grain or meet already formed gel. Production of new gel is accompanied by the production of portlandite (blue), which grows in clusters in the water (black).

In 3 (equivalent to 20% hydration), most of the cement grains have yet to react. A layer of C-S-H gel (yellow) surrounds most of the grains. There are well-formed portlandite (blue) clusters and much remaining water (black).

In 4 (equivalent to 75% hydration), the cement grains are smaller and the C-S-H gel (yellow) and portlandite (blue) almost fill the void space. The simulation produces images remarkably similar to scanning electron microscope (SEM) photographs of partially hydrated cement (Fig. 2-25).

More recently, the aluminate phases have been added to the simulator (Bentz et al., 1994). Figure 2-26 shows a simulation of a partially hydrated C₃S/C₃A/gypsum system.
2-7 Classification of Portland cements

Portland cements are manufactured to meet certain chemical and physical standards that depend upon their application. To promote consistency of performance among cement manufacturers, classification systems and specifications have been established by various user groups. The best known systems are those of ASTM International (formerly the American Society for Testing and Materials) (ASTM C 150, *Standard Specification for Portland Cement*) and API (API Spec 10A, *Specification for Cements and Materials for Well Cementing*). The API classification scheme has been adopted by the ISO as Standard 10426-1, *Petroleum and natural gas industries - Cements and materials for well cementing - Part 1: Specification*.

2-7.1 Classification criteria

The principal chemical criterion for classifying Portland cements is the relative distribution of the main clinker phases, known as the “potential phase composition.” Limits on the amounts of alkalis, free CaO, MgO, SO₃, and insoluble residue as well as the loss on ignition (weight loss after burning) are also specified for some classes of Portland cements.

The most widely accepted method of expressing the relative amounts of the principal clinker phases relies upon a series of calculations based upon the oxide composition of the cement. This method, first introduced by Bogue (1929), is based upon various phase equilibria relationships between the cement components. Bogue’s method suffers from various limitations, but it nonetheless remains a yardstick by which cements are classified. The Bogue equations are listed in the sidebar on the next page. These equations are based on the assumption that chemical equilibrium is established at the clinker- ing temperature and is maintained throughout the critical cooling period. This introduces errors that can give seriously incorrect results (Taylor, 1964; Aldridge, 1982).

The Bogue calculation has been refined by Taylor (1989) by using more realistic phase compositions, with the result that the calculated mineralogical composition is more nearly representative of the true mineralogical composition, as determined by quantitative XRD analysis. Various other corrections have been proposed, but none has yet received general acceptance.
An improved technique for determining the phase composition of Portland cement is the Rietveld method for powder XRD (Young, 1995). The Rietveld method allows standardization of powder diffraction analysis through the use of calculated reference diffraction patterns based upon crystal structure models. The result is a set of refined crystal structure models for each phase in the clinker. From these data, one can obtain pattern intensity information that may be related to phase abundance. Today, this method is being used for quality control in cement production and to analyze the NIST reference clinkers.

Physical parameters that appear in specifications include the fineness of the cement and the performance of the cement according to standardized tests. The performance tests include measurements of thickening time, compressive strength, expansion, and free water. Appendix B presents a complete description of the test methods and equipment.

### 2-7.2 API and ISO classification systems

The requirements for well cements are more rigorous than those for construction cements. Well cements must perform over a wide range of temperatures and pressures and are exposed to subterranean conditions that construction cements do not encounter. Well cements require greater consistency from batch to batch to ensure predictable performance when various cement additives are introduced (Chapter 3).

There are currently eight classes of API-ISO Portland cements, designated A through H. They are arranged according to the depths at which they are placed and the temperatures and pressures to which they are exposed.

Within some classes, cements with varying degrees of sulfate resistance (as determined by C₃A content) are sanctioned: ordinary (O), moderate sulfate resistance (MSR), and high sulfate resistance (HSR). The chemical and physical specifications are listed in Tables 2-7 and 2-8. Table 2-9 lists typical compositions and surface-area ranges for certain API cements. Below is a general description of each API class, with its ASTM equivalent when appropriate.

Classes A, B, and C are products obtained by grinding Portland cement clinker, consisting essentially of hydraulic calcium silicates, usually containing one or more of the forms of calcium sulfate as an interground addition. At the option of the manufacturer, processing additions† may be used in the manufacture of the cement, provided such materials in the amounts used have been shown to meet the requirements of ASTM C 465, Standard specification for processing additions for use in the manufacture of Portland cement.

Class A: Intended for use when special properties are not required. Available only in O grade (similar to ASTM C 150, Type I).

Class B: Intended for use when conditions require moderate or high sulfate resistance. Available in both MSR and HSR grades (similar to ASTM C 150, Type II)

Class C: Intended for use when conditions require high early strength. Available in O, MSR, and HSR grades (similar to ASTM C 150, Type III).

---

† A suitable processing addition or set-modifying agent will not prevent a well cement from performing its intended functions.
<table>
<thead>
<tr>
<th>Cement Class</th>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D, E, F</th>
<th>G</th>
<th>H</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(wt%)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td><strong>Ordinary grade (O)</strong></td>
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<td></td>
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<td>6.0</td>
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<tr>
<td>Max. sulfur trioxide (SO₃)</td>
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<td>Max. loss on ignition</td>
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<tr>
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<td></td>
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<tr>
<td>Max. tricalcium silicate (3CaO • SiO₂)</td>
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<tr>
<td>Min. tricalcium silicate (3CaO • SiO₂)</td>
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<td>48</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Max. tricalcium aluminatate (3CaO • Al₂O₃)</td>
<td>8</td>
<td>8</td>
<td>8</td>
<td>8</td>
<td>8</td>
<td>8</td>
</tr>
<tr>
<td>Max. total alkali content expressed as sodium oxide (Na₂O) equivalent</td>
<td>0.75</td>
<td>0.75</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>High sulfate-resistant grade (HSR)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Max. magnesium oxide (MgO)</td>
<td>6.0</td>
<td>6.0</td>
<td>6.0</td>
<td>6.0</td>
<td>6.0</td>
<td>6.0</td>
</tr>
<tr>
<td>Max. sulfur trioxide (SO₃)</td>
<td>3.0</td>
<td>3.5</td>
<td>3.0</td>
<td>3.0</td>
<td>3.0</td>
<td>3.0</td>
</tr>
<tr>
<td>Max. loss on ignition</td>
<td>3.0</td>
<td>3.0</td>
<td>3.0</td>
<td>3.0</td>
<td>3.0</td>
<td>3.0</td>
</tr>
<tr>
<td>Max. insoluble residue</td>
<td>0.75</td>
<td>0.75</td>
<td>0.75</td>
<td>0.75</td>
<td>0.75</td>
<td>0.75</td>
</tr>
<tr>
<td>Max. tricalcium silicate (3CaO • SiO₂)</td>
<td>65</td>
<td>65</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Min. tricalcium silicate (3CaO • SiO₂)</td>
<td>48</td>
<td>48</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Max. tricalcium aluminatate (3CaO • Al₂O₃)</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
</tr>
<tr>
<td>Max. tetracalcium aluminoferrite (4CaO • Al₂O₃ • Fe₂O₃) plus twice the tricalcium aluminatate (3CaO • Al₂O₃)</td>
<td>24</td>
<td>24</td>
<td>24</td>
<td>24</td>
<td>24</td>
<td>24</td>
</tr>
<tr>
<td>Max. total alkali content expressed as sodium oxide (Na₂O) equivalent</td>
<td>0.75</td>
<td>0.75</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

† From API Specification 10A. Reproduced courtesy of the American Petroleum Institute.
Table 2-8. Physical Requirements for API Portland Cements†

<table>
<thead>
<tr>
<th></th>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
<th>E</th>
<th>F</th>
<th>G</th>
<th>H</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mix water (percent BWOC‡)</td>
<td>40</td>
<td>40</td>
<td>50</td>
<td>30</td>
<td>30</td>
<td>30</td>
<td>40</td>
<td>30</td>
</tr>
<tr>
<td>Min. Blaine fineness (specific surface area, tabidimeter (m²/kg))</td>
<td>150</td>
<td>160</td>
<td>220</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Min. fineness (specific surface area, air permeability (m²/kg))</td>
<td>280</td>
<td>280</td>
<td>400</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Max. free fluid content (mL)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>3.5</td>
<td>3.5</td>
</tr>
</tbody>
</table>

Table 2-9. Typical Composition and Fineness of API Cements‡

<table>
<thead>
<tr>
<th>API Class</th>
<th>ASTM Type</th>
<th>Typical Potential Phase Composition (wt%)</th>
<th>Typical Blaine Fineness (cm²/g)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>I</td>
<td>C₃S 45  β-C₂S 27  C₃A 11  C₄AF 8</td>
<td>1,600</td>
</tr>
<tr>
<td>B</td>
<td>II</td>
<td>C₃S 44  β-C₂S 31  C₃A 5  C₄AF 13</td>
<td>1,600</td>
</tr>
<tr>
<td>C</td>
<td>III</td>
<td>C₃S 53  β-C₂S 19  C₃A 11  C₄AF 9</td>
<td>2,200</td>
</tr>
<tr>
<td>D</td>
<td>II</td>
<td>C₃S 28  β-C₂S 49  C₃A 4  C₄AF 12</td>
<td>1,500</td>
</tr>
<tr>
<td>E</td>
<td>-</td>
<td>C₃S 38  β-C₂S 43  C₃A 4  C₄AF 9</td>
<td>1,500</td>
</tr>
<tr>
<td>G</td>
<td>Nominal II</td>
<td>C₃S 50  β-C₂S 30  C₃A 5  C₄AF 12</td>
<td>1,800</td>
</tr>
<tr>
<td>H</td>
<td>Nominal II</td>
<td>C₃S 50  β-C₂S 30  C₃A 5  C₄AF 12</td>
<td>1,600</td>
</tr>
</tbody>
</table>

† From API Spec 10A. Reproduced courtesy of the American Petroleum Institute.
‡ By weight of water
§ – = not available

Table 2-9. Typical Composition and Fineness of API Cements‡

1 From API Spec 10A. Reproduced courtesy of the American Petroleum Institute.
2 By weight of water
3 – = not available

Table 2-9. Typical Composition and Fineness of API Cements‡

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<th>Typical Blaine Fineness (cm²/g)</th>
</tr>
</thead>
<tbody>
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<td>A</td>
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<td>C₃S 45  β-C₂S 27  C₃A 11  C₄AF 8</td>
<td>1,600</td>
</tr>
<tr>
<td>B</td>
<td>II</td>
<td>C₃S 44  β-C₂S 31  C₃A 5  C₄AF 13</td>
<td>1,600</td>
</tr>
<tr>
<td>C</td>
<td>III</td>
<td>C₃S 53  β-C₂S 19  C₃A 11  C₄AF 9</td>
<td>2,200</td>
</tr>
<tr>
<td>D</td>
<td>II</td>
<td>C₃S 28  β-C₂S 49  C₃A 4  C₄AF 12</td>
<td>1,500</td>
</tr>
<tr>
<td>E</td>
<td>-</td>
<td>C₃S 38  β-C₂S 43  C₃A 4  C₄AF 9</td>
<td>1,500</td>
</tr>
<tr>
<td>G</td>
<td>Nominal II</td>
<td>C₃S 50  β-C₂S 30  C₃A 5  C₄AF 12</td>
<td>1,800</td>
</tr>
<tr>
<td>H</td>
<td>Nominal II</td>
<td>C₃S 50  β-C₂S 30  C₃A 5  C₄AF 12</td>
<td>1,600</td>
</tr>
</tbody>
</table>

1 From Nelson, 1983. Reprinted with permission from Oil & Gas Journal.
2 Not applicable
2-8 Acronym list

AFm Aluminoferrite monosulfate
AFt Aluminoferrite trisulfate
API American Petroleum Institute
BET Brunauer-Emmett-Teller (gas adsorption method of determining surface area)
BWOW By weight of water
C-S-H Calcium silicate hydrate
FTIR Fourier transform infrared (spectroscopy)
HSR High sulfate resistance
ISO International Organization for Standardization
MSR Moderate sulfate resistance
NIST National Institute of Standards and Technology
O Ordinary (an indication of cement sulfate resistance)
OPC Ordinary Portland cement
SEM Scanning electron microscope
XRD X-ray diffraction

Classes D, E, and F:
The products obtained by grinding Portland cement clinker, consisting essentially of hydraulic calcium silicates, usually containing one or more of the forms of calcium sulfate as an interground addition. At the option of the manufacturer, processing additions may be used in the manufacture of the cement, provided such materials in the amounts used have been shown to meet the requirements of ASTM C 465. Further, at the option of the manufacturer, suitable set-modifying agents may be interground or blended during manufacture. This product is intended for use under conditions of moderately high temperatures and pressures. Available in MSR and HSR grades.

Classes D, E, and F are also known as “retarded cements,” intended for use in deeper wells. The retardation is accomplished by significantly reducing the amount of faster-hydrating phases (C₃S and C₃A) and increasing the particle size of the cement grains. Since these classes were first manufactured, the technology of chemical retarders has significantly improved; consequently, these classes are rarely found today.

Classes G and H:
The products obtained by grinding Portland cement clinker, consisting essentially of hydraulic calcium silicates, usually containing one or more of the forms of calcium sulfate as an interground addition. No additions other than calcium sulfate or water, or both, shall be interground or blended with clinker during manufacture of Class G well cement. This product is intended for use as a basic well cement. Available in MSR and HSR grades.

Classes G and H were developed in response to the improved technology in slurry acceleration and retardation by chemical means. The cement manufacturer is prohibited from adding special chemicals, such as glycols or acetates, to the clinker. Such chemicals improve the efficiency of grinding but have been shown to interfere with various cement additives. Classes G and H are by far the most commonly used well cements today.
3-1 Introduction

Portland cement systems for well cementing are routinely designed to perform at temperatures ranging from below freezing in permafrost zones to 700°F [350°C] in thermal-recovery and geothermal wells. Well cements encounter the pressure range from near ambient in shallow wells to more than 30,000 psi [200 MPa] in deep wells. In addition to severe temperatures and pressures, well cements must often be designed to contend with weak or porous formations, corrosive fluids, and overpressured formation fluids. Cement additives make it possible to accommodate such a wide range of conditions. Additives modify the behavior of the cement system, ideally allowing successful slurry placement between the casing and the formation, rapid compressive strength development, and adequate zonal isolation during the lifetime of the well.

Today more than 100 additives for well cements are available, many of which can be supplied in solid or liquid forms. There are eight major categories of additives.

1. **Accelerators**: chemicals that reduce the setting time of a cement system and increase the rate of compressive strength development
2. **Retarders**: chemicals that delay the setting time of a cement system
3. **Extenders**: materials that lower the density of a cement system, reduce the quantity of cement per unit volume of set product, or both
4. **Weighting agents**: materials that increase the density of a cement system
5. **Dispersants**: chemicals that reduce the viscosity of a cement slurry
6. **Fluid-loss control agents**: materials that control leakage of the aqueous phase of a cement system to the formation
7. **Lost-circulation control agents**: materials that control loss of the cement slurry to weak or vugular formations
8. **Specialty additives**: miscellaneous additives, such as antifoam agents, fibers, and flexible particles.

Each of the above categories is discussed individually in this chapter. The physical and chemical phenomena that affect additive performance, additive examples, and proposed mechanisms of action are discussed in detail. A thorough review of Chapter 2 is recommended before reading this chapter.

3-2 Variability of additive response

Typical performance data for many additives are presented throughout this chapter. It is important for the reader to understand that this information is presented solely to illustrate general trends and should not be used for design purposes. Most additives are strongly influenced by the chemical and physical properties of the cement, which are highly variable even within a given American Petroleum Institute (API) or International Organization for Standardization (ISO) classification. Consequently, a wide spectrum of results can be obtained with the same slurry design. The important cement parameters include the following:

- particle-size distribution
- distribution of silicate and aluminate phases
- reactivity of hydrating phases
- gypsum/hemihydrate ratio and total sulfate content
- free alkali content
- chemical nature, quantity, and specific surface area of initial hydration products.

Other important parameters that influence additive performance include temperature, pressure, additive concentration, mixing energy, mixing order, and water-to-cement ratio.

Figure 3-1 illustrates the variability of additive response to cements. The figure compares the hydration behavior of two API/ISO Class G cements. Conduction calorimetry curves were generated for the neat slurries and for three additional slurries containing an accelerator, a retarder, or a dispersant. Scrutiny of the curves reveals significant differences in hydration behavior.

Because of the complexity of the cement hydration process and the large number of parameters involved, the only practical cement slurry design method (to avoid unpleasant surprises at the wellsite) is thorough laboratory testing before the job.
and expert systems can propose “first-guess” cement formulations that are consistent with the required performance criteria (Chapter 12). This can help reduce the number of tests required to achieve the final design. It is essential that the tests be performed with a representative sample of the cement and mix water to be used during the cement job.

3-3 Accelerators

Accelerators are added to cement slurries to shorten the setting time (Stages I and II of the hydration scheme described in Chapter 2), accelerate the hardening process (Stages III and IV), or both. They are often used to counteract the set delay caused by other additives, such as dispersants and fluid-loss-control agents (Odler et al., 1978).

3-3.1 Examples

Many inorganic salts are accelerators of Portland cement. Chloride salts are used most frequently. Other salts that have an accelerating effect include carbonates, silicates (especially sodium silicate), aluminates, nitrates, sulfates, thiosulfates, and alkaline bases [e.g., sodium hydroxide (NaOH), potassium hydroxide (KOH), and ammonium hydroxide (NH₄OH)]. Among the chlorides, the accelerating effect becomes stronger as the valence and ionic radius of the accompanying cation increases (Skalny and Maycock, 1975). Edwards and Angstadt (1966) suggested that cations and anions may be ranked according to their efficiency as accelerators for Portland cement.

\[
\text{Ca}^{2+} > \text{Mg}^{2+} > \text{Li}^+ > \text{Na}^+ > \text{H}_2\text{O} \\
\text{OH}^- > \text{Cl}^- > \text{Br}^- > \text{NO}_3^- > \text{SO}_4^{2-} = \text{H}_2\text{O}
\]

Calcium chloride (CaCl₂) is undoubtedly the most efficient and economical of all accelerators. Regardless of concentration, it always acts as an accelerator (Table 3-1). It is normally added at concentrations between 2% to 4% by weight of cement (BWOC) (Appendix C). Results are unpredictable at concentrations exceeding 6% BWOC, and premature setting may occur.

Sodium chloride affects the thickening time and compressive strength development of Portland cement in different ways, depending upon its concentration and the curing temperature (Fig. 3-2). NaCl acts as an accelerator at concentrations up to 15% by weight of mix water (BWOW). Between 15% and 20% BWOW, NaCl is essentially neutral, and thickening times are similar to those obtained with fresh water. The addition of NaCl at
concentrations above 20% BWOW causes retardation. NaCl is not a very efficient accelerator and should be used only when CaCl₂ is not available at the wellsite.

Seawater is used extensively for mixing cement slurries at offshore locations. It contains up to 2.5 wt% NaCl, resulting in acceleration. The presence of magnesium in seawater (about 0.15 wt%) must also be taken into account (Chapter 7).

Chloride-free accelerators, originally developed by the concrete industry to reduce the corrosion of reinforcing steel, are also used in well cements. Sodium silicate is normally used as a cement extender; however, it also has an accelerating effect. Sodium silicate reacts with Ca²⁺ ions in the aqueous phase of the cement slurry to form additional calcium silicate hydrate (C-S-H) phase nuclei, thus hastening the end of the induction period. Other examples include alkaline earth formates, nitrates, nitrites, triethanolamine, and thiocyanates (Pauri et al., 1986; Ramachandran, 1973; 1976a).

### Table 3-1. Effects of Calcium Chloride on the Performance of Portland Cement Systems

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>6 hr</td>
<td>12 hr</td>
<td>24 hr</td>
<td>6 hr</td>
<td>12 hr</td>
<td>24 hr</td>
</tr>
<tr>
<td>0</td>
<td>4:00</td>
<td>3:30</td>
<td>2:32</td>
<td>Not set</td>
<td>60</td>
<td>415</td>
</tr>
<tr>
<td>2</td>
<td>1:17</td>
<td>1:11</td>
<td>1:01</td>
<td>125</td>
<td>480</td>
<td>1,510</td>
</tr>
<tr>
<td>4</td>
<td>1:15</td>
<td>1:02</td>
<td>0:59</td>
<td>125</td>
<td>650</td>
<td>1,570</td>
</tr>
</tbody>
</table>

**Fig. 3-2.** Effect of sodium chloride on thickening time and compressive strength development.

3-3.2 Calcium chloride—mechanisms of action

Calcium chloride is by far the most common accelerator of Portland cement. The mechanisms by which it operates are complex and still not completely understood. Several hypotheses described in the literature are summarized below.

3-3.2.1 Effects of calcium chloride on the hydration of principal Portland cement phases

It has been proposed that calcium chloride increases the hydration rate of the aluminate phases–gypsum system (Bensted, 1978; Traetteberg and Grattan-Bellew, 1975). Chloride ions enhance the formation of ettringite until the gypsum is consumed (Tenoutasse, 1978). If free C₃A remains, calcium monochloroaluminate (C₃A • CaCl₂ • 10H₂O) forms. The more rapid setting of the cement slurry is also attributed to the crystalline shape of ettringite, which occurs as very fine needles (Bensted, 1978; Young et al., 1973).

By contrast, Stein (1961a) and Edwards and Angstadt (1966) concluded that accelerators do not promote the hydration of C₃A but instead accelerate the hydration of
This accelerating action of calcium chloride has been confirmed by studying the hydration of pure C₃S (Odler and Skalny, 1971a) and C₂S (Collepardi and Massidda, 1973).

### 3.3.2.2 Change in C-S-H structure

Many researchers have proposed that Portland cement hydration is controlled by the diffusion of water and ionic species through the initial protective C-S-H phase coating (Chapter 2). Therefore, the hydration rate should be influenced by the permeability of the coating. A morphological change of the C-S-H phase to a more open, flocculated structure would enhance diffusion and accelerate hydration. Such a process has been confirmed in studies of pure C₃S (Odler and Skalny, 1971a; Ben-Dor and Perez, 1976; Traetteberg et al., 1974). The C-S-H phase has a higher bulk lime-to-silica (C/S) ratio and a “crumpled-foil” morphology rather than a spicular or needle-like appearance. In the presence of calcium chloride, C-S-H phase has a greater specific surface area (Collepardi and Marchese, 1972) and a greater degree of silicate-anion polymerization (Hirljac et al., 1983). A change in the pore-size distribution of hydrated C₃S (Young et al., 1973; Skalny et al., 1971) and C₂S (Odler and Skalny, 1971b) has also been reported. The morphology of calcium hydroxide (portlandite) is also affected by the presence of chloride ions (Berger and McGregor, 1972). The portlandite crystals become elongated.

### 3.3.3 Diffusion of chloride ions

Kondo et al. (1977) determined the diffusion rate of anions and cations from alkaline and alkaline-earth chlorides through a set–Portland cement plate. They concluded that the diffusion coefficient of the chloride ion is much higher than that of the accompanying cation. Because the chloride ions diffuse into the C-S-H phase layer more quickly than the cations, a counterdiffusion of hydroxyl ions must occur to maintain the electrical balance. Therefore, the precipitation of portlandite, ending the induction period, takes place earlier. Kondo et al. (1977) also established that only a small amount of chloride is incorporated into the C-S-H lattice but that it may be chemically bound to the C-S-H surface.

Others studied the effect of calcium chloride on C₃S hydration. They concluded that the accelerating effect occurred because chloride ions have a smaller ionic size than hydroxyl ions and would more easily diffuse into the C-S-H membrane. The resulting internal-pressure increase takes place more quickly, causing the C-S-H membrane to burst earlier.

### 3.3.2.4 Change in aqueous phase composition

Michaux et al. (1989a and 1989b) showed that calcium chloride strongly modifies the distribution of ionic species in the aqueous phase of well-cement slurries. Chloride ions do not participate in the formation of hydration products during the induction period; therefore, one observes a decreased concentration of hydroxyl and sulfate ions and an increased concentration of calcium ions. Kurczyk and Schwiete (1960) proposed that calcium chloride decreases the alkalinity of the aqueous phase, resulting in acceleration.

Stadelmann and Wieker (1985) investigated the influence of a large number of inorganic salts on the hydration of C₃S. They showed that C₃S hydration is accelerated by increasing the solubility of calcium hydroxide in the aqueous phase, e.g., by adding CaCl₂. Conversely, retardation is observed when the solubility of calcium hydroxide decreases, e.g., by adding high concentrations of NaCl.

Wu and Young (1984) showed that the addition of calcium salts affects the dissolution rate of C₃S. When the concentration of calcium in the aqueous phase is monitored with time, the peak concentration always occurs earlier in the presence of chloride ions. Thus, precipitation of calcium hydroxide (and the end of the induction period) occurs earlier.

In conclusion, it is apparent that many factors interact simultaneously in the acceleration of Portland cement by calcium chloride. Both physical and chemical phenomena are involved. The presence of chloride ions alters the structure and increases the permeability of the C-S-H phase layer. In addition, calcium chloride significantly alters the distribution of ionic species in the aqueous phase, resulting in a faster hydration rate.

### 3.3.3 Secondary effects of calcium chloride

In addition to acceleration of the initial set, several other effects are evident when calcium chloride is present in a Portland cement system. Some effects are not beneficial; therefore, calcium chloride should be used judiciously depending upon well conditions. A summary of the more important secondary effects is given below.

#### 3.3.3.1 Heat of hydration

The presence of CaCl₂ increases the rate of heat generation during the first hours after slurry mixing. If the wellbore is thermally insulated to a sufficient degree, the temperature of the cement, casing, and surrounding formation can increase by as much as 50°C–60°F [27°C–33°C] after slurry placement. An autoacceleration of hydration results.
More importantly, increased casing expansion occurs because of the temperature rise. Because steel casing and cement do not have the same coefficient of thermal expansion, the casing may shrink away from the cement when the hydration heat eventually dissipates. This results in a so-called “thermal microannulus,” and zonal isolation is compromised (Pilkington, 1988). Additional research is needed to better quantify this effect and to determine the most susceptible wellbore environments.

3-3.3.2 Slurry rheology
According to Collepardi (1971), calcium chloride increases the yield point of a cement slurry but initially does not affect the plastic viscosity. After a 30-min hydration period at ambient conditions, the plastic viscosity begins to increase. Slurries containing calcium chloride also tend to have a greater degree of thixotropy; as a result, particle sedimentation is seldom a problem.

3-3.3.3 Compressive strength development
Calcium chloride significantly increases the rate of compressive strength development during the first few days after slurry placement. The magnitude of this effect depends upon the curing temperature and the CaCl₂ concentration (Table 3-1).

3-3.3.4 Shrinkage
Calcium chloride has been shown to increase volumetric shrinkage by 10% to 50% in concretes (Shideler, 1952). This is mainly owing to the greater degree of hydration and changes in hydration products (Collepardi and Massidda, 1973). Such data cannot be directly translated to well cements, because the service conditions are very different. To the authors’ knowledge, a thorough investigation of the dimensional stability of calcium chloride-accelerated well cements has not been performed. The magnitude of the shrinkage effect in concrete and the popularity of calcium chloride as an accelerator for well cements suggest that such a study is overdue.

3-3.3.5 Permeability
Initially, the permeability of set cement containing calcium chloride is reduced. This is caused by the greater volume of hydration products compared to an additive-free cement. Later, when the degree of hydration is similar for both systems, the permeability of the set cement containing CaCl₂ is greater than that of its additive-free counterpart (Gouda et al., 1973).

3-3.3.6 Sulfate resistance
Because the ultimate permeability of calcium chloride-accelerated systems is greater, the resistance to aggressive sulfate solutions is reduced (Shideler, 1952; Gouda et al., 1973). However, as discussed in Chapter 2, the C₃A content of the cement is the principal controlling factor governing sulfate resistance.

3-3.4 Chloride-free accelerators
Although calcium chloride is the least expensive and most effective accelerator, growing concern about its corrosion of the reinforcing steel embedded in Portland cement concrete has led to the development of chloride-free additives. Casing corrosion from chloride accelerators may also be a concern during the life of a well.

Under normal conditions, steel reinforcement is protected from corrosion (passivated) by the high pH of the surrounding concrete-pore solution. A thin protective film of gamma ferric oxide (γ-Fe₂O₃) forms on the steel surface. The protective film prevents iron cations (Fe²⁺) from entering the electrolyte and acts as a barrier to prevent oxygen anions (O²⁻) from contacting the steel surface. If the passivation is compromised, corrosion of the reinforcement can occur at a high rate. The protective film can be disrupted by a significant reduction of the pore-solution pH because of carbonation or by the penetration of aggressive ions such as chlorides to the steel-concrete interface.

A plethora of inorganic and organic compounds, including alkali carbonates, alkali silicates, alkali aluminates, alkali sulfates, alkali hydroxides, nitrates, thiocyanates, thiosulfates, formates, and alkanolamines, have been evaluated as calcium-chloride replacements. However, very few have performed well enough to be used on an industrial scale. Unlike calcium chloride, which is generally added alone, most of the commercial chloride-free accelerators are formulated and contain several components.

Calcium formate, Ca(HCOO)₂, was patented as a cement accelerator in 1965. Owing to its low solubility in water, calcium formate is usually sold as a powder. The normal dosage is 1–2% BWOC. Calcium formate accelerates the hydration and setting of all types of Portland cement, but its effect is not significant within the first 24 hr. Early strength development can be improved by including sodium nitrite as an accelerator aid (Rosskopf et al., 1975).

The use of calcium nitrite, Ca(NO₂)₂, as an accelerator was patented by Angstadt and Hurley in 1963. Its water solubility is very high; therefore, it can be used as a liquid additive. The effect of calcium nitrite on strength development is comparable to that of calcium
chloride (Rosenburg et al., 1977). Calcium nitrite is also an effective corrosion inhibitor for steel embedded in concrete (Berke, 1985).

Calcium nitrate, Ca(NO₃)₂, in conjunction with triethanolamine, is an effective accelerator (Tokay, 1982); however, its efficiency is highly variable depending on the cement type. Technical calcium nitrate, a blend of calcium- and ammonium-nitrate hydrates, has a dual function as a set accelerator and corrosion inhibitor for reinforced concrete (Justnes and Nygaard, 1995).

Thiocyanate (SCN⁻) salts were introduced to the concrete market in 1983 (Rosskopf, 1983). Like the nitrates, the thiocyanates should be accompanied by an alkanolamine to attain the desired results. The combination of thiocyanate salts with nitrates and alkanolamines was patented in 1984 (Gerber, 1984).

Triethanolamine, N(C₂H₄OH)₃, accelerates the reaction between C₃A and gypsum and, at dosages of 0.1 and 0.5% BWOC, setting can occur within a few minutes at ambient temperature (Ramachandran, 1973; 1976b). However, compressive strength development can be delayed because triethanolamine strongly retards C₃S and C₂S hydration. Therefore, triethanolamine is rarely used by itself as an accelerator.

A complex mixture of calcium nitrate, calcium nitrite, diethylene glycol, methyldiethanolamine, and calcium bromide was recently patented as an accelerator for well cements (Maberry et al., 2001). It is used in cold cementing environments such as deepwater offshore wells or permafrost zones. The performance of this additive (Fig. 3-3) is superior to calcium chloride at temperatures between about 40° and 70°F [5° and 20°C]. Unlike calcium chloride, this accelerator does not affect slurry rheology at elevated concentrations.

3-4 Retarders

Like acceleration, the mechanisms of Portland-cement retardation are still a subject of controversy. Several theories have been proposed, but none fully explains the retardation process by itself. Two principal factors must be considered: the chemical nature of the retarder and the cement phase (silicate or aluminate) upon which the retarder acts. The four principal theories are summarized below.

1. Adsorption theory: The retarder adsorbs onto the surfaces of the hydration products, thereby inhibiting contact with water.

2. Precipitation theory: The retarder reacts with calcium ions, hydroxyl ions, or both in the aqueous phase, forming an insoluble and impermeable layer around the cement grains.

3. Nucleation theory: The retarder adsorbs onto the nuclei of hydration products, arresting their future growth.

4. Complexation theory: The retarder chelates the calcium ions, preventing the formation of nuclei.

It is probable that all of the above theories are involved to some extent in the retardation process.

Despite the uncertainty regarding the mechanisms of retardation, the chemical technology is very well developed. The major chemical classes of retarders, as well as proposed mechanisms of action, are discussed individually below.

3-4.1 Lignosulfonates

The most commonly used retarders for well cements are the sodium and calcium salts of lignosulfonic acids (Fig. 3-4). Lignosulfonates are polymers derived from wood pulp; therefore, they are usually unrefined and contain various amounts of saccharide compounds. The average molecular weight varies from about 20,000 to 30,000. Purified lignosulfonates have much less retarding power; therefore, the retarding action is often attributed to the impurities in the bulk material. Such impuri-
ties include low-molecular-weight carbohydrates such as pentoses (xylose and arabinose), hexoses (mannose, glucose, fructose, rhamnose, and galactose), and aldonic acids (especially xylonic and gluconic acids) (Chatterji, 1967; Milestone, 1976; 1979).

Lignosulfonate retarders are effective with all Portland cements and are generally added in concentrations ranging from 0.1% to 1.5% BWOC (Fig. 3-5). Depending upon the lignosulfate retarders’ carbohydrate content and chemical structure (e.g., molecular weight distribution and degree of sulfonation) and the nature of the cement, they are effective to about 250°F [122°C] bottomhole circulating temperature (BHCT). When blended with sodium borate (Section 3-4.6), the effective temperature range of lignosulfonates can be extended to as high as 600°F [315°C] BHCT.

Lignosulfonate retarders predominantly affect the kinetics of C₃S hydration; however, their effects upon C₃A hydration are not insignificant (Stein, 1961b; Angstadt and Hurley, 1963). The retardation mechanism of the lignosulfonates is generally thought to be a combination of the adsorption and nucleation theories.

Lignosulfonate retarders perform best with low-C₃A cements. When C₃A is hydrated in the presence of organic additives such as lignosulfonates, the solution concentration of the additives quickly falls. C₃A hydration products have a much stronger adsorptive effect than those of C₃S (Blank et al., 1963; Rossington and Runk, 1968). In a Portland cement system, C₃A hydration can prevent a significant amount of lignosulfonate from reaching the surfaces of C₃S hydration products; as a result, the retarder is less efficient (Young, 1969).

Ramachandran (1972) showed that the sulfonate and hydroxyl groups adsorb onto the C-S-H phase layer. As a result, the permeability of the C-S-H phase is reduced (Ciach and Swenson, 1971). A waterproofing mechanism, preventing further significant hydration, has also been proposed (Jennings et al., 1986).

Some of the lignosulfonate remains in the aqueous phase. It may be in a free state or linked to calcium ions through electrostatic interactions. At low lignosulfonate concentrations, the crystal growth (and probably the nucleation) of calcium hydroxide is inhibited (Jawed et al., 1979). Although the same experiment has not yet been performed with C-S-H phase, a similar result would be expected. A significant change in the size and morphology of the calcium hydroxide crystals is observed when C₃S is hydrated in the presence of lignosulfonates (Berger and McGregor, 1972). These results suggest that, if the nucleation and crystal growth of the hydration products are hindered by the lignosulfonate, the hydration rate of C₃S will be similarly affected.

### 3-4.2 Hydroxycarboxylic acids

Hydroxycarboxylic acids contain hydroxyl and carboxyl groups in their molecular structures (Fig. 3-6). Gluconate and glucoheptonate salts and tartaric acid are the most widely used materials in this category. They have a powerful retarding action and can easily cause overretardation at BHCTs less than 200°F [93°C]. As shown in Fig. 3-7, these materials are efficient to temperatures approaching 300°F [150°C].

![Figure 3-5](image1.png)

**Figure 3-5.** Typical effect of a lignosulfonate retarder on a 15.8-lbm/gal [1,900 kg/m³] Class G cement.

![Figure 3-6](image2.png)

**Figure 3-6.** Molecular structures of hydroxycarboxylic acid retarders.
Another hydroxycarboxylic acid with a strong retarding effect is citric acid. Citric acid is also an effective cement dispersant (Section 3-5) and is normally used at concentrations between 0.1% and 0.3% BWOC.

The retarding action of hydroxycarboxylic acids and their salts is generally attributed to the presence of alpha- or beta-hydroxycarboxylic groups (HO-C-CO₂H and HO-C-C-CO₂H, respectively) that are capable of strongly chelating a metal cation such as calcium (Double, 1983). Highly stable five- or six-membered rings form, partially adsorb onto the hydrated cement surface, and poison the nucleation sites of hydration products. Like the lignosulfonates, hydroxycarboxylic acids are more efficient with low-C₃A cements.

### 3-4.3 Saccharide compounds

Saccharide compounds (also called sugars) are excellent Portland cement retarders (Fig. 3-8). The best performers contain a five-membered ring (e.g., sucrose and raffinose) (Bruere, 1966; Previte, 1971; Thomas and Birchall, 1983). Such compounds are not commonly used in well cementing, because the degree of retardation is very sensitive to small variations in concentration.

The retarding action of saccharide compounds depends upon their susceptibility to degradation by alkaline hydrolysis. The sugars are converted to saccharinic acids containing alpha-hydroxycarbonyl groups (HO-C-C=O), which adsorb strongly onto C-S-H phase surfaces (Taplin, 1960). Hydration is inhibited when the C-S-H phase nucleation sites are inactivated (poisoned) by the adsorbed sugar acid anions (Milestone, 1979).

### 3-4.4 Cellulose derivatives

Cellulose polymers are polysaccharides derived from wood or other plants. They are stable in the alkaline environment of cement slurries. Set retardation occurs when the polymer adsors onto the hydrated cement surfaces. The active sites for adsorption are the ethylene-oxide links and carbonyl groups.

The most common cellulosic retarder is carboxymethylhydroxyethylcellulose (CMHEC) (Shell and Wynn, 1958). Its molecular structure is shown in Fig. 3-9. CMHEC is an effective retarder at temperatures up to about 250°F [121°C] (Rust and Wood, 1966). Typical performance data are presented in Fig. 3-10.

A number of secondary effects are observed with CMHEC. It is often used as a fluid-loss control agent (Section 3-8). In addition, CMHEC significantly increases the viscosity of the slurry.

### 3-4.5 Organophosphonates

In the 1980s, alkylene phosphonic acids and their salts were identified as set-retarding additives for well cements (Nelson, 1984; Sutton et al., 1985; Childs et al., 1986; Nelson, 1987). Phosphomethylated compounds containing quaternary ammonium groups (Crump and Wilson, 1984), as well as N-phosphonomethyl imidodiacetic acid (Huddleston, 1995) are also efficient. Such materials have excellent hydrolytic stability and, depending upon the molecular backbone, are effective to circulating temperatures as high as 450°F [232°C].
Organophosphonates are advantageous for well cementing because of their apparent insensitivity to subtle variations in cement composition and their tendency to lower the viscosity of high-density cement slurries. The mechanism of action involves the adsorption of phosphonate groups (Fig. 3-11) onto the nuclei of cement hydrates, thus hindering their growth.

Methylenephosphonic acid derivatives can be used to prepare cement slurries with very long thickening times. The set can then be activated when needed (e.g., by an aqueous solution of sodium silicate) (Childs et al., 1987). They can also be used to retard ultrafine cements (Blaine fineness of greater than 6,000 cm²/g) at circulating temperatures up to about 400°F [204°C] (Brothers, 1994; Rodrigues and Lindsey, 1995). Ultrafine cement slurries are used for squeeze cementing and well repair (Chapters 7 and 14).

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Figure 3-9. CMHEC molecular structure and illustration of degree of substitution (DS) and molecular substitution (MS) concepts.

Figure 3-10. Typical CMHEC concentrations required to obtain 3- to 4-hr thickening times (using Class A and Class H cements).

Figure 3-11. Alkylene phosphonate structure.
At temperatures above about 230°F [110°C], methylenephosphonic acid derivatives are poor retarders of the aluminate (C₃A) and aluminoferrite (C₄AF) phases, but they strongly retard the silicate phases (C₃S and C₂S) (unpublished data, M. Michaux, 1993). As a result, thickening times are short and compressive strength development is slow. Adding a borate salt to the retarder formulation solves this problem. At an appropriate phosphonate/borate ratio, longer thickening times and swift compressive strength development can be achieved at circulating temperatures up to 450°F [232°C] (Nelson, 1984; Nelson and Casabonne, 1992; Barlet-Gouédard et al., 1996; Casabonne et al., 1996) (Fig. 3-12).

3-4.6 Inorganic compounds
Many inorganic compounds retard the hydration of Portland cement. The major classes of materials are listed below.

- Acids and salts thereof: boric, phosphoric, hydrofluoric, and chromic
- Sodium chloride: concentrations greater than 20% BWOW (Section 3-2)
- Oxides: zinc and lead

In well cementing, zinc oxide (ZnO) is sometimes used for retarding thixotropic cements, because it does not affect the slurry rheology (Chapter 7) or the hydration of the C₃A-gypsum system (Ramachandran, 1986). The retardation effect of ZnO is attributed to the precipitation of zinc hydroxide onto the cement grains (Arliguie and Grandet, 1985). Zn(OH)₂ has a low solubility ($K_s = 1.8 \times 10^{-14}$) and is deposited as a colloidal gel; consequently, the precipitate has a low permeability. The retardation effect ends when the gelatious zinc hydroxide eventually transforms to crystalline calcium hydroxyzincate.

$$2\text{Zn(OH)}_2 + 2\text{OH}^- + \text{Ca}^{2+} + 2\text{H}_2\text{O} \rightarrow \text{CaZn}_2(\text{OH})_6 \cdot 2\text{H}_2\text{O}$$  
(3-1)

Sodium tetraborate decahydrate (borax: Na₂B₄O₇ • 10H₂O) is commonly used as a “retarder aid.” It has the ability to extend the effective temperature range of most lignosulfonate retarders to as high as 600°F [315°C]; however, it can be detrimental to the effectiveness of cellulosic and polyamine fluid-loss additives.

3-5 Extenders
Cement extenders are routinely used to accomplish one or both of the following.

- Reduce slurry density: A reduction of slurry density reduces the hydrostatic pressure during cementing. This helps to prevent induced lost circulation because of the breakdown of weak formations. In addition, the number of stages required to cement a well may be reduced.
- Increase slurry yield: Extenders reduce the amount of cement required to produce a given volume of set product. This results in a greater economy.

Extenders can be classified into one of three categories, depending upon the mechanism of density reduction and/or yield increase. Often more than one type of extender is used in the same slurry.

- Water extenders: Clays and various water viscosifying agents allow the addition of more water to achieve slurry extension. Such extenders maintain a homogeneous slurry and prevent the development of excessive free water.
- Low-density aggregates: This varied category consists of materials with densities lower than that of Portland cement (3.20 g/cm³). The slurry density is reduced when significant quantities of such extenders are present.
- Gaseous extenders: Nitrogen or air can be used to prepare foamed cements with exceptionally low densities yet sufficient compressive strength. The preparation and placement of such cement systems are described in Chapters 7 and 13.

Table 3-2 presents a list of the common extenders, with general information regarding their performance characteristics.
Clays
Clay minerals are hydrous aluminum silicates of the phyllosilicate group (Hurlbut, 1971), in which the silica tetrahedra are arranged in sheets. Such minerals have a platy or flaky shape and one prominent cleavage. Magnesium or iron can partially substitute for aluminum in the crystal lattice, and alkalis or alkaline earths may also be present as essential components.

The most frequently used clay-base extender is bentonite, also known as “gel,” which contains at least 85% of the mineral smectite. Smectite, NaAl₂(AlSi₃O₁₀)(OH)₂, is composed of two flat sheets of silica tetrahedra sandwiching one sheet of alumina octahedra. Bentonite has the unusual property of expanding to several times its original volume when placed in water, resulting in higher fluid viscosity, gel strength, and solids-suspending ability. Bentonite is obtained primarily from mines in Wyoming and South Dakota; however, foreign sources are being developed (Samsuri et al., 2001).

Bentonite is added in concentrations up to 20% BWOC. Above 6%, the addition of a dispersant is usually necessary to reduce the slurry viscosity and gel strength. The API/ISO recommends that 5.3% additional water (BWOC) be added for each 1% bentonite for all classes of cement; however, testing is necessary to determine the optimal water content with a particular cement. As shown in Table 3-3, the slurry density decreases and the yield increases with bentonite concentration; however, as shown in Fig. 3-13, there is a price to be paid in terms of compressive strength. Cement permeability also increases with bentonite concentration; therefore, such cements are less resistant to sulfate waters and corrosive fluids. However, as explained in Section 3-3.8.1, high concentrations of bentonite tend to improve fluid-loss control.

High concentrations of Ca²⁺ ion in the aqueous phase of a cement slurry inhibit the hydration of bentonite. The extension efficiency of bentonite can be greatly enhanced if it is prehydrated in the mix water before cement addition. A slurry containing 2% prehydrated bentonite BWOC is equivalent to one containing 8% dry-blended bentonite (Table 3-4). Complete hydration of a good-quality bentonite occurs in about 30 min. The thickening times of prehydrated bentonite slurries are generally the same as those of dry-blended slurries at the same density. It should also be noted that prehydrating the bentonite does not appreciably change the final compressive strength when compared to an equal-density slurry prepared with dry-blended bentonite.

### Table 3-2. Summary of Extenders

<table>
<thead>
<tr>
<th>Extender</th>
<th>Range of Slurry Densities Obtainable (lbm/gal)</th>
<th>Performance Features and Other Benefits</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>6 11 16</td>
<td></td>
</tr>
<tr>
<td>Bentonite</td>
<td>11.5 15</td>
<td>Assists fluid-loss control</td>
</tr>
<tr>
<td>Fly ashes</td>
<td>13.1 14.1</td>
<td>Resist corrosive fluids</td>
</tr>
<tr>
<td>Sodium silicates</td>
<td>11.1 14.5</td>
<td>Available in solid or liquid form; effective at low concentrations; ideal when mixing slurry with seawater</td>
</tr>
<tr>
<td>Microspheres</td>
<td>8.5 15</td>
<td>Good compressive strength, low permeability, thermal stability, and insulating properties</td>
</tr>
<tr>
<td>Foamed cement</td>
<td>6 15</td>
<td>Good compressive strength and low permeability</td>
</tr>
</tbody>
</table>

### Table 3-3. Effect of Bentonite on Cement-Slurry Properties

<table>
<thead>
<tr>
<th>% Bentonite Water Slurry Density Yield</th>
<th>(gal/sk)</th>
<th>(lbm/gal)</th>
<th>(ft³/sk)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>4.97</td>
<td>15.8</td>
<td>1.14</td>
</tr>
<tr>
<td>2</td>
<td>6.17</td>
<td>15.0</td>
<td>1.31</td>
</tr>
<tr>
<td>4</td>
<td>7.36</td>
<td>14.4</td>
<td>1.48</td>
</tr>
<tr>
<td>6</td>
<td>8.56</td>
<td>13.9</td>
<td>1.65</td>
</tr>
<tr>
<td>8</td>
<td>9.76</td>
<td>13.5</td>
<td>1.82</td>
</tr>
<tr>
<td>10</td>
<td>10.95</td>
<td>13.1</td>
<td>1.99</td>
</tr>
<tr>
<td>12</td>
<td>12.15</td>
<td>12.7</td>
<td>2.16</td>
</tr>
<tr>
<td>16</td>
<td>14.55</td>
<td>12.3</td>
<td>2.51</td>
</tr>
<tr>
<td>20</td>
<td>16.94</td>
<td>11.9</td>
<td>2.85</td>
</tr>
</tbody>
</table>

![Figure 3-13. Effect of bentonite on compressive strength.](image-url)
According to API/ISO specifications, only pure, untreated bentonite should be used in well cements. Beneficiating agents such as polyacrylamide, which improve the water absorption capacity of low-grade bentonites, are prohibited. Such materials can interfere with the performance of other cement additives and lead to unpredictable results (Grant et al., 1990).

Bentonite can be prehydrated in seawater or light brine, but the salt inhibits hydration and the slurry yield is reduced. Bentonite is not effective as an extender in highly saline cement slurries. Under such circumstances, another clay mineral, attapulgite, is frequently used (Smith and Calvert, 1974). Attapulgite, \((\text{Mg,Al})_5\text{Si}_8\text{O}_{22}(\text{OH})_4 \cdot 4\text{H}_2\text{O}\), also known as “salt-gel,” occurs as fibrous needles. When dispersed in water, the attapulgite needles associate with one another and provide viscosity. Unlike bentonite, attapulgite does not improve fluid-loss control. Attapulgite has been banned in some countries, because the fibrous needles are similar to those of asbestos (Bensted, 2001). However, granular forms of attapulgite are available that are still permitted in many locations.

### 3-5.2 Sodium silicates

Silicate extenders react with lime or calcium chloride in the cement to form a calcium silicate gel. The gel structure provides sufficient viscosity to allow adding extra mix water without excessive free-water separation. Sodium silicates are available in solid or liquid form. A major advantage of the silicates is their efficiency, which minimizes storage and handling. However, because of their tendency to accelerate, they tend to reduce the effectiveness of other additives, retarders and fluid-loss agents in particular.

The solid sodium silicate, \(\text{Na}_2\text{SiO}_3\) (sodium metasilicate), is normally dry-blended with the cement. If it is added to fresh mix water before slurry preparation, a gel may not form unless calcium chloride is also added. If a gel does not form, proper slurry extension will not occur. The recommended concentration range of \(\text{Na}_2\text{SiO}_3\) is 0.2% to 3.0% BWOC. These concentrations provide a slurry-density range of from 14.5 to 11.0 lbm/gal \([1.75\text{ to } 1.35 \text{ g/cm}^3]\). The typical properties and performance of sodium metasilicate-extended cement systems are shown in Table 3-5.

The liquid sodium silicate, \(\text{Na}_2\text{O} \cdot (3-5)\text{SiO}_2\) (also called water glass), is added to the mix water before slurry mixing. If calcium chloride is to be included in cement systems mixed with fresh water, it must be added to the mix water before the sodium silicate to obtain sufficient extending properties. In the case of slurries mixed with seawater, sodium silicate will interact with the divalent cations in the seawater to achieve slurry extension. The normal concentration range is 0.2 to 0.6 gal/sk. Typical performance data are presented in Table 3-6.

<p>| Table 3-4. Comparison of Prehydrated and Dry-Blended Bentonite Slurry Properties |
|---------------------------------|----------|-----------|-----------|----------|----------|</p>
<table>
<thead>
<tr>
<th>Prehydrated Dry Bentonite (%)</th>
<th>Dry-Blended Bentonite (%)</th>
<th>Fresh Water (gal/sk)</th>
<th>Slurry Density (lbm/gal)</th>
<th>Slurry Yield (ft³/sk)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Prehydrated Dry Blend</td>
<td>Prehydrated Dry Blend</td>
<td>Prehydrated Dry Blend</td>
<td>Prehydrated Dry Blend</td>
<td>Prehydrated Dry Blend</td>
</tr>
<tr>
<td>0</td>
<td>0</td>
<td>5.2</td>
<td>14.8</td>
<td>1.34</td>
</tr>
<tr>
<td>0.5</td>
<td>2</td>
<td>6.4</td>
<td>14.8</td>
<td>1.35</td>
</tr>
<tr>
<td>1.0</td>
<td>4</td>
<td>7.6</td>
<td>14.1</td>
<td>1.50</td>
</tr>
<tr>
<td>1.5</td>
<td>6</td>
<td>8.8</td>
<td>13.5</td>
<td>1.66</td>
</tr>
<tr>
<td>2.0</td>
<td>8</td>
<td>10.0</td>
<td>13.1</td>
<td>1.83</td>
</tr>
<tr>
<td>2.5</td>
<td>10</td>
<td>11.2</td>
<td>12.7</td>
<td>1.99</td>
</tr>
<tr>
<td>3.0</td>
<td>12</td>
<td>12.4</td>
<td>12.4</td>
<td>2.16</td>
</tr>
<tr>
<td>4.0</td>
<td>16</td>
<td>14.8</td>
<td>11.9</td>
<td>2.48</td>
</tr>
<tr>
<td>5.0</td>
<td>20</td>
<td>17.2</td>
<td>11.5</td>
<td>2.81</td>
</tr>
</tbody>
</table>
Pozzolans are perhaps the most important group of cement extenders. They are defined in accordance with ASTM International\(^\text{†}\) designation C-219-55 as follows:

“A silicious or siliceous and aluminous material, which in itself possesses little or no cementitious value, but will, in finely divided form and in the presence of moisture, chemically react with calcium hydroxide at ordinary temperatures to form compounds possessing cementitious properties.”

Thus, pozzolans not only extend Portland cement systems, but also react with the calcium hydroxide liberated during cement hydration and contribute to the compressive strength of the set product. There are two

<table>
<thead>
<tr>
<th>Sodium Metasilicate (% BWOC)</th>
<th>Slurry Density (lbm/gal [kg/m(^3)])</th>
<th>Water Compressive Strength at 24 hr (psi [MPa])</th>
<th>Thickening Time (hr:min)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(gal/sk [L/SI ton])</td>
<td>@120°F [60°C]</td>
<td>@140°F [60°C]</td>
</tr>
<tr>
<td>0</td>
<td>15.8 [1,900]</td>
<td>4.97 [440]</td>
<td>44</td>
</tr>
<tr>
<td>0.75</td>
<td>12.5 [1,501]</td>
<td>11.75 [1,050]</td>
<td>104</td>
</tr>
<tr>
<td>1.0</td>
<td>11.5 [1,381]</td>
<td>16.6 [1,480]</td>
<td>147</td>
</tr>
</tbody>
</table>

\(†\) Not available

<table>
<thead>
<tr>
<th>Slurry Density (lbm/gal [kg/m(^3)])</th>
<th>Liquid Silicate Concentration (gal/sk [L/SI ton])</th>
<th>Thickening Time at BHCT (hr:min)</th>
<th>Compressive Strength at BHST(^\text{†}) After 24 hr (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>14.2 [1,700]</td>
<td>0.20 [17.8]</td>
<td>2.20</td>
<td>1.40</td>
</tr>
<tr>
<td>13.6 [1,630]</td>
<td>0.30 [26.7]</td>
<td>3.00</td>
<td>2.00</td>
</tr>
<tr>
<td>13.0 [1,560]</td>
<td>0.36 [32.0]</td>
<td>3.40</td>
<td>2.20</td>
</tr>
<tr>
<td>12.5 [1,500]</td>
<td>0.42 [37.4]</td>
<td>3.00</td>
<td>2.30</td>
</tr>
<tr>
<td>12.0 [1,440]</td>
<td>0.50 [44.5]</td>
<td>3.00</td>
<td>4.00</td>
</tr>
<tr>
<td>11.5 [1,380]</td>
<td>0.60 [53.4]</td>
<td>4.00</td>
<td>4.00</td>
</tr>
</tbody>
</table>

\(†\) Bottomhole static temperature

\(\dagger\) Not available

### 3-5.3 Pozzolans

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Thus, pozzolans not only extend Portland cement systems, but also react with the calcium hydroxide liberated during cement hydration and contribute to the compressive strength of the set product. There are two

\(\dagger\) ASTM International was formerly known as the American Society for Testing and Materials (ASTM).
types of pozzolans: (1) natural pozzolans, which include volcanic ashes and diatomaceous earth, and (2) artificial pozzolans, such as certain fly ashes.

When one 94-lbm sack of cement hydrates, about 20 to 23 lbm of free Ca(OH)\textsubscript{2} are liberated. By itself, Ca(OH)\textsubscript{2} contributes little to the strength of the set cement and is fairly soluble; thus, it can be eventually dissolved and removed by water contacting the cement. This contributes to a weakening of the set cement. When a pozzolan is present, the silica combines with the free Ca(OH)\textsubscript{2} to form a stable cementitious compound (secondary C-S-H) that is very durable.

At typical cement densities, the water permeability of set pozzolan/cement systems is usually less than 0.001 mD. The low permeability of the set cement, as well as the decrease of free Ca(OH)\textsubscript{2} content, resists the encroachment of sulfate water and other corrosive fluids. Should corrosive waters manage to enter the set pozzolanic cement, damage is further prevented by another mechanism. Zeolites in the pozzolan act as ion exchange agents and help prevent deterioration.

There are two notation systems commonly used for mixing pozzolan cements. The first is a bulk/volume ratio. A 1:1 ratio indicates 1 ft\textsuperscript{3} of pozzolan and 1 ft\textsuperscript{3} of cement. The first figure always indicates the volume of pozzolan, and the second indicates the volume of cement. This system is used primarily with very light pozzolans.

The second mixing system is the most widely used. It is based on the “equivalent sack.” A sack of Portland cement has an absolute volume of approximately 3.59 gal. In other words, when mixed with water, one sack of cement will increase the volume of the mix by about 3.59 gal. An equivalent sack is the weight of pozzolan that also has an absolute volume of 3.59 gallons. Different pozzolans have different equivalent sack weights. The ratio for mixtures based upon equivalent sacks is designated as 25:75, 50:50, 75:25, or whatever ratio is desired. The term 25:75 indicates ⅘ eq sk of pozzolan and ¾ eq sk of Portland cement.

The weights of other additives (except salt) are calculated as a percentage by weight of the pozzolan/cement equivalent sack. Salt is always calculated as a percentage of the mix-water volume.

As an example, an equivalent sack of one typical fly ash is 74 lbm. A 50:50 blend would require 37 lbm of fly ash and 47 lbm of Portland cement. Thus, 84 lbm of this blend would displace 3.59 gal. Additive concentrations would then be calculated as a percentage of an 84-lbm equivalent sack, not the usual 94-lbm sack of Portland cement. A more detailed discussion of pozzolanic slurry calculations is presented in Appendix C.

### 3-5.3.1 Diatomaceous earth

Diatomaceous earth is composed of the siliceous skeletons of diatoms deposited from either fresh water or seawater. The main constituent of diatomaceous earth is opal, an amorphous form of hydrous silica containing up to 10% water. For use as a pozzolanic extender, diatomaceous earth is ground to a fineness approaching that of Portland cement; consequently, it has a large surface area and a high water demand.

Diatomaceous earth imparts slurry properties similar to those of bentonite slurries; however, it does not increase the slurry viscosity to such a high degree. In addition, because of its pozzolanic activity, set cements containing diatomaceous earth are stronger than their bentonitic counterparts. The principal disadvantage of diatomaceous earth is its cost. Typical slurry properties and performance of diatomaceous earth slurries are shown in Table 3-7.

<table>
<thead>
<tr>
<th>Diatomaceous Earth (%BWOC)</th>
<th>Water (gal/sk)</th>
<th>Slurry Weight (lbm/gal)</th>
<th>Slurry Yield (ft\textsuperscript{3}/sk)</th>
<th>Compressive Strength After 24 Hr of Curing (psi)</th>
<th>Compressive Strength After 72 Hr of Curing (psi)</th>
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<tr>
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<td></td>
<td></td>
<td></td>
<td>80°F and Ambient Pressure</td>
<td>95°F and 600 psi Pressure</td>
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<td>1.18</td>
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<td>1,580</td>
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<td>13.2</td>
<td>1.92</td>
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<td>3.12</td>
<td>na†</td>
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<tr>
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<td>25.6</td>
<td>11.0</td>
<td>4.19</td>
<td>15</td>
<td>30</td>
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</tbody>
</table>

† Not available
### 3-5.3.2 Fly ashes

Fly ash is the residue from power plants that burn pulverized coal (Davis et al., 1937). The ash is suspended in flue gases as fused particles that solidify into a roughly spherical shape. The ash is very finely divided, with a surface area roughly approximating that of Portland cements. The major constituent of fly ash is a glass chiefly composed of silica and alumina with some iron oxide, lime, alkalis, and magnesia. Quartz, mullite, hematite, and magnetite, as well as some combustible matter, are also found. The composition and properties of fly ash can vary widely depending upon the source of the coal and the efficiency of the power plant; accordingly, the specific gravities of fly ashes can vary from about 2.0 to 2.7 (Hewlett, 2001).

According to ASTM International specifications, three types of fly ash are recognized: Types N, F, and C. As shown in Table 3-8, the distinction is made on chemical grounds. Types N and F are normally produced from burning anthracite or bituminous coals. Type C fly ashes, made from lignite or subbituminous coals, are less siliceous, and some contain more than 10% lime; as a result, many of them are cementitious and do not fit the strict definition of a pozzolanic material. In well cementing, Type F fly ash is used most frequently.

Normally, 2% bentonite is added to Type F fly ash/Portland cement systems to improve the slurry properties and prevent the development of free water. In Table 3-9, slurry data for different ratios of Type F fly ash and cement are presented with various water contents.

The use of Type C fly ashes as extenders for well cements is relatively new. Because of the significant amount of lime in such fly ashes, the rheological effects must be carefully monitored. In addition, Type C ashes vary widely depending upon the source, and special slurry preparation guidelines are required for each.

Some Type C fly ashes are sufficiently cementitious to be used as the principal component of a well cement. Such systems have been developed for application in shallow wells having circulating temperatures up to 120°F [49°C]. Compressive strength development is often more rapid than that observed with conventional Portland cement systems.

### 3-5.3.3 Commercial lightweight cements

Commercial oilwell cements, such as TXI Lightweight‡, are special formulations composed of interground Portland cement clinker and lightweight siliceous aggregates; consequently, some pozzolanic activity occurs. They are convenient and time-saving for the service company. The particle-size distribution is finer than in Portland cements, and the normal slurry density range is from 11.9 to 13.7 lbm/gal [1.43 to 1.64 g/cm³].

![Table 3-8. Chemical Requirements for Fly Ashes](image)

<table>
<thead>
<tr>
<th>Mineral Admixture Class</th>
<th>N</th>
<th>F</th>
<th>C</th>
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</thead>
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<tr>
<td>Min. silicon dioxide (SiO₂) + aluminum oxide (Al₂O₃) + iron oxide (Fe₂O₃) (%)</td>
<td>70</td>
<td>70</td>
<td>50</td>
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<tr>
<td>Max. sulfur trioxide (SO₃) (%)</td>
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<td>5</td>
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<tr>
<td>Max. moisture content (%)</td>
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<td>3</td>
<td>3</td>
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<tr>
<td>Max. loss on ignition (%)</td>
<td>10</td>
<td>12</td>
<td>6</td>
</tr>
</tbody>
</table>

![Table 3-9. Properties of Fly Ash/Class H Cement Systems](image)

<table>
<thead>
<tr>
<th>Ratio</th>
<th>Weight of Components (lbm)</th>
<th>Min. Water Requirement</th>
<th>Max. Water Requirement</th>
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</thead>
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<tr>
<td></td>
<td>Fly Ash</td>
<td>Class H Cement</td>
<td>Fly Ash</td>
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<tr>
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<tr>
<td>75</td>
<td>25</td>
<td>55.5</td>
<td>23.5</td>
</tr>
</tbody>
</table>

1. All systems contain 2% bentonite by weight of fly ash/cement blend.
2. Based on the weight of an equivalent sack of the specific blend.

‡TXI Lightweight is a trademark of Texas Industries.
3-5.3.4 Silica

Three forms of finely divided silica are used in well cements: α-quartz, condensed silica fume, and colloidal silica dispersions. Silica as α-quartz is used most frequently for the prevention of strength retrogression when Portland cement systems are placed in thermal wells (Chapter 10). Two particle sizes are routinely used: silica sand, with an average particle size of about 100 μm, and silica flour, with an average particle size of about 15 μm. Other sizes of crystalline silica are used in special cement systems with controlled particle-size distributions (Chapter 7). Because of cost, these materials are rarely used for slurry extension alone.

Condensed silica fume (also called microsilica) is a byproduct of the production of silicon, ferrosilicon, and other silicon alloys. The individual particles are glassy, amorphous microspheres. The mean particle size is usually between 0.1 μm and 0.2 μm, about 50 to 100 times finer than Portland cement or fly ash; consequently, the surface area is extremely high (15,000 to 25,000 m²/kg).

Condensed silica fume is highly reactive and, because of its fineness and purity, is a very effective pozzolanic material (Parker, 1985). Its high degree of pozzolanic activity has led to the introduction of low-density cement systems with a higher rate of compressive strength development (Carathers and Crook, 1987). The high surface area of condensed silica fume increases the amount of water required to prepare a pumpable slurry; therefore, slurries with densities as low as 12.0 lbm/gal [1.44 g/cm³] have little or no free water. The normal concentration of this material is about 15% BWOC; however, up to 28% BWOC is possible.

The fineness of condensed silica fume also promotes improved fluid-loss control, perhaps by reducing the permeability of the initial cement filtercake (Mueller and Dillenbeck, 1991). For this reason, it is also used for the prevention of annular fluid migration (Chapter 9) (Grinrod et al., 1988; Golapudi et al., 1993). In addition, it is used as a source of silica in thermal cement systems (Chapter 10) (Grabowski and Gillot, 1988; Noik et al., 1998). High retarder concentrations are often required owing to the high specific surface area of silica fume.

Colloidal silica dispersions are aqueous sols of pure amorphous silica and traces of sodium hydroxide. Like microsilica, colloidal silica particles are spherical; however, the particle size is about one order of magnitude smaller (0.05 μm). Therefore, the surface area of colloidal silica is about 500,000 m²/kg. The primary applications of colloidal silica are to prepare low-density cement systems and to prevent annular fluid migration (Bjordal et al., 1993).

3-5.4 Lightweight particles

Lightweight-particle extenders reduce the slurry density because they are lighter than the cement particles. Such extenders include expanded perlite, powdered coal, gilsonite, and either glass or ceramic microspheres. Most extenders in this category are inert with respect to the cement.

3-5.4.1 Expanded perlite

Perlite is a crushed volcanic glass that expands when heated to the point of incipient fusion (Lea, 1971). The expanded perlite product generally has a bulk density of 7.75 lbm/ft³, which allows the preparation of competent cement slurries with densities as low as 12.0 lbm/gal [1.44 g/cm³]. A small quantity of bentonite (2% to 4% BWOC) is added to prevent the segregation of the perlite particles from the slurry.

Expanded perlite contains both open and closed pores. Under hydrostatic pressure, the open pores fill with water, and some of the closed pores are crushed; as a result, the perlite becomes more dense. To maintain density control, the use of perlite is confined to shallow wells.

To prepare an expanded perlite slurry that will have a given density downhole, it is necessary to mix a lower-density slurry at the surface. At 3,000 psi [20.7 MPa], the specific gravity of expanded perlite is 2.40. Table 3-10 shows some typical slurry designs and illustrates how the slurry density increases between atmospheric pressure and 3,000 psi [20.7 MPa]. Owing to the density variability, perlite is rarely used today.

3-5.4.2 Gilsonite

Gilsonite is a naturally occurring asphaltite mineral, found primarily in northeastern Utah. The specific gravity of gilsonite is 1.05. The water requirement for gilsonite is low, about 2 gal/ft³; thus, it is possible to prepare low-density cement systems with relatively high compressive strength (Slagle and Carter, 1959). Up to 50 lbm of gilsonite can be used per sack of Portland cement to achieve slurry densities as low as 12.0 lbm/gal [1.44 g/cm³]. However, mixing difficulties may occur at such high concentrations. Bentonite is often included in the slurry to keep the gilsonite particles evenly dispersed.

Gilsonite is a black, angular solid, normally supplied as a ground material with a wide particle-size distribution (up to 0.6 cm). It is often used to prevent lost circulation (Chapter 6). Gilsonite has a melting point of 385°F [196°C]. Some softening occurs above 240°F [116°C], and the particles may tend to fuse. As a result, gilsonite is not recommended for use in wells with bottomhole static temperatures above 300°F [149°C].
<table>
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<tr>
<th>Cement Perlite Ratio (by volume)</th>
<th>Bentonite Mix Water (gal/sk)</th>
<th>Atmospheric Slurry Density (lbm/gal)</th>
<th>Slurry Volume (ft³/sk)</th>
<th>3,000 psi Slurry Density (lbm/gal)</th>
<th>Slurry Volume (ft³/sk)</th>
<th>Compressive Strength (at 24 hr, 100°F, 3,000 psi)</th>
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</tr>
</tbody>
</table>

† Data are based on Class A cement.
‡ Not available
3-5.4.3 Powdered coal

The performance of powdered coal as an extender is very similar to that of gilsonite. Its specific gravity is slightly greater (1.30). Like gilsonite, it is coarsely ground (50% of particles between 6 and 12 mesh) and is often used to prevent lost circulation. Unlike gilsonite, the melting point of powdered coal is high—1,000°F [538°C]. Therefore, powdered coal can be used in thermal well environments.

Between 12.5 and 25 lbm of powdered coal are normally added per sack of cement to prepare slurries with densities as low as 11.9 lbm/gal [1.43 g/cm³]. Bentonite is often added to such slurries to prevent the coal from segregating. Table 3-11 illustrates typical slurry designs for powdered coal systems.

<table>
<thead>
<tr>
<th>Bentonite (%BWOC)</th>
<th>Powdered Coal (lbn/sk)</th>
<th>Water (gal/sk)</th>
<th>Slurry Density (lbn/gal)</th>
<th>Slurry Volume (ft³/sk)</th>
<th>Bentonite (%BWOC)</th>
<th>Powdered Coal (lbn/sk)</th>
<th>Water (gal/sk)</th>
<th>Slurry Density (lbn/gal)</th>
<th>Slurry Volume (ft³/sk)</th>
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3.5.4.4 Microspheres

Microspheres are small gas-filled beads with specific gravities normally between 0.2 and 0.9. Such low specific gravities allow the preparation of high-strength, low-permeability cements with densities as low as 7.5 lbm/gal [1.02 g/cm³] without the need for nitrogen. Two types of microspheres are available: glass and ceramic.

The original application of microspheres was for primary cementing of conductor and surface pipes, in which washouts and low formation fracturing pressures are common. However, they are used much more extensively today, and in many cases microsphere cements have eliminated the need for multistage cementing. Microspheres have also found use in special cement systems with controlled particle-size distributions (Chapter 7). A significant limitation of microspheres is their inability to withstand high hydrostatic pressure without being crushed; thus, they cannot be used in deep wells. Microsphere cement systems require special care in design and mixing, and these special procedures are briefly described below.

Glass microspheres are manufactured from borosilicate glass. Several grades are commercially available, and the specific gravity varies from 0.12 to 0.80 (Smith et al., 1980). All grades have roughly the same particle-size distribution (30–40 μm), and their pressure resistance is directly related to specific gravity. Most grades of glass microspheres withstand pressures up to 5,000 psi [34.5 MPa]; however, the heavier grades with thicker walls will survive to 10,000 psi [68.9 MPa]. Glass microspheres are significantly more expensive than their ceramic counterparts; thus, their use is relatively infrequent.

Ceramic microspheres, also called cenospheres, are derived from ash produced by coal-burning power plants. Their composition is variable, but the principal constituents are silica and alumina (Table 3-12). The material is mainly amorphous; however, small amounts of mullite are sometimes detected by X-ray diffraction. They have low reactivity in a Portland cement matrix; however, some pozzolanic behavior can occur at high curing temperatures (Drochon and Maroy, 2000).

The particle-size range is between 20 and 500 μm. The shell thickness is about 10% of the particle radius. The composition of the gas inside is a mixture of CO₂ and N₂. The microspheres are heavier than their glass counterparts, with a specific gravity of 0.6–0.9 and a bulk density of 25 lbm/ft³; thus, a higher concentration is necessary to achieve low slurry densities (Harms and Sutton, 1981).

As mentioned earlier, both glass and ceramic microspheres are susceptible to breakage and collapse when exposed to high hydrostatic pressure; as a result, the density of the slurry increases (Messenger, 1974). The pressure resistance of ceramic microspheres can vary widely depending upon the source (Fig. 3-14). This increase can be predicted and, as shown in Fig. 3-15, can be taken into account in the design calculations. When the microspheres are crushed, the slurry volume decreases and the packing volume fraction changes. This can lead to significantly higher slurry viscosities. The use of ceramic microspheres is not recommended when bottomhole pressures exceed 4,500 psi [31 MPa].

It is important to ensure that the microspheres do not separate from the cement particles during the blending process. The microspheres must be thoroughly dry-blended with the cement and not premixed in the water. Any variation in the ratio of microspheres to cement will result in erratic densities during mixing. The bulk volume of microspheres is high relative to their specific gravity; therefore, when preparing blends, it is important to ensure that the capacity of the blending equipment is adequate.

### Table 3-12. Typical Chemical Composition of Cenospheres

<table>
<thead>
<tr>
<th>Component</th>
<th>Composition</th>
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<tr>
<td>Silica (SiO₂)</td>
<td>50%–65%</td>
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<tr>
<td>Alumina (Al₂O₃)</td>
<td>20%–45%</td>
</tr>
<tr>
<td>Iron oxide (Fe₂O₃)</td>
<td>1%–10%</td>
</tr>
<tr>
<td>Calcium (CaO)</td>
<td>0.2%–4%</td>
</tr>
<tr>
<td>Magnesium (MgO)</td>
<td>0.5%–2%</td>
</tr>
<tr>
<td>Titanium (TiO₂)</td>
<td>0.5%–2%</td>
</tr>
<tr>
<td>Alkali (Na₂O, K₂O)</td>
<td>0.5%–4%</td>
</tr>
</tbody>
</table>

![Figure 3-14. Percent crushing of two sources of cenospheres versus hydrostatic pressure.](image)
Microspheres are compatible with any class of cement. Figure 3-16 illustrates the amount of microspheres required to achieve slurry densities between 8.5 and 15.0 lbm/gal [1.02 and 1.80 g/cm³]. Mix water requirements are shown in Fig. 3-17 and slurry yields in Fig. 3-18. The relationship between the density of ceramic microsphere system density and compressive strength is illustrated in Table 3-13.

**Figure 3-15.** Density of cenosphere-extended slurries versus pressure.

**Figure 3-16.** Typical cenosphere concentration requirements versus slurry density.

**Figure 3-17.** Water requirements for cenosphere-extended cement systems.

**Figure 3-18.** Yield of cenosphere-extended cement systems.
3-5.4.5 Nitrogen

Foamed cement is a system in which nitrogen is incorporated directly into the slurry to obtain a low-density cement. The system requires the use of specially formulated base cement slurries to prepare a homogeneous system with high compressive strength and low permeability. Incorporating nitrogen allows the preparation of competent cement systems with densities as low as 7.0 lbm/gal [0.84 g/cm³]. The reader is referred to Chapter 7 for a complete discussion of this important technology.

3-6 Weighting agents

High pore pressures, unstable wellbores, and deformable or plastic formations are controlled by high hydrostatic pressures. Under such conditions, mud densities in excess of 18.0 lbm/gal [2.16 g/cm³] are common. To maintain control of such wells, cement slurries of equal or greater density are also necessary.

One method of increasing the cement-slurry density is simply to reduce the amount of mix water. To maintain pumpability, the addition of a dispersant is required. The principal disadvantage of reduced-water slurries is the difficulty of simultaneously achieving adequate fluid-loss control, acceptable slurry rheology, and no solids settling. Without excellent fluid-loss control, the risk of slurry bridging is higher. If solids settling occurs, the compressive strength and bonding will not be uniform across the cemented interval. The maximum slurry density attainable by reducing mix water is 18.0 lbm/gal [2.16 g/cm³].

When higher slurry densities are required, materials with a high specific gravity are added. Such materials must meet several criteria to be acceptable as weighting agents.

- The particle-size distribution of the material must be compatible with the cement. Large particles tend to settle out of the slurry, while small particles tend to increase slurry viscosity.
- The mix water requirement must be low.
- The material must be inert with respect to cement hydration and compatible with other cement additives.

The most common weighting agents for cement slurries are ilmenite, hematite, barite, and manganese tetraoxide. A summary of their physical properties appears in Table 3-14. The concentrations of each material normally required to achieve a given slurry density are plotted in Fig. 3-19.

### Table 3-13. Compressive-Strength Data For Cenosphere-Extended Cement Systems Mixed with Class G Cement + 1% Calcium Chloride†

<table>
<thead>
<tr>
<th>Curing Pressure (psi)</th>
<th>Compressive Strength Data (psi)</th>
<th>Slurry Mixing Densities (lbm/gal)</th>
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</thead>
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<td></td>
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</tr>
<tr>
<td>0</td>
<td>55</td>
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<tr>
<td>3,000</td>
<td>215</td>
<td>250</td>
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</table>

† All slurries were cured for 24 hr at 80°F.
‡ Not available

### Table 3-14. Physical Properties of Weighting Agents for Cement Slurries

<table>
<thead>
<tr>
<th>Material</th>
<th>Specific Gravity</th>
<th>Absolute Volume (gal/lbm)</th>
<th>Color</th>
<th>Additional Water Requirement (gal/lbm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ilmenite</td>
<td>4.45</td>
<td>0.027</td>
<td>Black</td>
<td>0.00</td>
</tr>
<tr>
<td>Hematite</td>
<td>4.95</td>
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<tr>
<td>Barite</td>
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<td>0.028</td>
<td>White</td>
<td>0.024</td>
</tr>
<tr>
<td>Manganese tetraoxide</td>
<td>4.84</td>
<td>0.025</td>
<td>Reddish brown</td>
<td>0.0011</td>
</tr>
</tbody>
</table>
3-6.1 Ilmenite
Ilmenite (FeTiO₃), a black granular material, has a specific gravity of 4.45. It has little effect on cement hydration. As currently supplied, the particle-size distribution of ilmenite is rather coarse; therefore, the slurry viscosity must be carefully adjusted to prevent sedimentation. Slurry densities in excess of 20.0 lbm/gal [2.4 g/cm³] are easily attainable with ilmenite.

3-6.2 Hematite
With a specific gravity of 4.95, hematite (Fe₂O₃) is a very efficient weighting agent. The material occurs as red crystalline granules. Unlike ilmenite, it is currently supplied with a fine particle-size distribution. At high hematite concentrations, addition of a dispersant is often necessary to prevent excessive slurry viscosity. Hematite is routinely used to prepare cement slurries with densities up to 19.0 lbm/gal [2.28 g/cm³]; however, slurries with densities as high as 22 lbm/gal [2.64 g/cm³] can be prepared.

3-6.3 Barite
Barite (BaSO₄), a white powdery material, is readily available at most oilfield locations; however, it is not an efficient weighting agent compared to ilmenite, hematite, or manganese tetraoxide. Although it has a high specific gravity (4.33), additional water is required to wet its particles, which diminishes its effectiveness as a densifier. The additional water also decreases the compressive strength of the set cement. Nevertheless, slurries with densities up to 19.0 lbm/gal [2.28 g/cm³] can be prepared with barite.

3-6.4 Manganese tetraoxide
Manganese tetraoxide (Mn₃O₄), a reddish-brown powder, has a specific gravity of 4.84. It is available in both solid and liquid-slurry forms. The latter form is convenient for offshore applications. The particles are very small (average size 5 μm), resulting in a significantly greater particle surface area than other weighting agents. The tendency to settle is less than for hematite, and manganese tetraoxide can be added directly to the mix water (Johnston and Senese, 1992). This allows last-minute

Figure 3-19. Densification of cement slurries with various weighting agents.
slurry density changes for primary cement jobs or emergency plugback jobs. Owing to its very high fineness, magnesium tetraoxide can sometimes shorten the thickening time of a slurry. Slurries with densities as high as 22 lbm/gal [2.64 g/cm³] can be prepared when manganese tetraoxide is used in combination with hematite.

3-7 Dispersants

Well cement slurries are highly concentrated suspensions of solid particles in water. Their rheological properties are related to those of the supporting liquid rheology, the solid volume fraction (volume of particles/volume of slurry), and interparticle interactions. The aqueous phase of a cement slurry contains ionic species and organic additives. Therefore, the rheological properties of the aqueous phase can differ greatly from those of water, notably when high-molecular-weight water-soluble polymers (e.g., fluid-loss control agents) are added. The viscosity of the interstitial fluid can also vary significantly with temperature.

The solid volume fraction (SVF) can vary from about 0.2 for extended slurries (Section 3-5) to about 0.7 for reduced-water slurries. High SVF values generally result in high slurry viscosities, unless the controlled granulometry process is employed (Chapter 7). Particle interactions depend primarily on the surface-charge distribution and steric hindrance effects caused by organic molecules adsorbed at the solid-particle surfaces.

Without modification, most cement slurries would not have the correct rheological properties for proper placement in long, narrow annuli. Cement dispersants, also known in the construction industry as plasticizers and superplasticizers, are used to obtain the desired rheological properties.

This section discusses the various dispersant chemistries and the mechanisms by which they work. The most important factors affecting the response of cement slurries to dispersants are also discussed.

3-7.1 Chemical composition of cement dispersants

The first category of cement dispersants, known as plasticizers in the concrete industry, includes lignosulfonates, modified lignosulfonates, and hydroxycarboxylic acids such as citric acid, tartaric acid, salicylic acid, gluconic acid, and glucoheptonic acid. Most plasticizers act as powerful cement retarders (Double, 1983), and in the well cementing industry they are considered more in this context than as dispersants (Messenger, 1978).

A second category of dispersants, known as superplasticizers in the concrete industry, includes polynaphthalene sulfonate, polyethylene sulfonate, and other sulfonated polymers such as polystyrene sulfonate and polycarboxylate-based products.

Lignosulfonates are most frequently used as dispersants in drilling-mud formulations (Lummus and Azar, 1986) but are also effective in cement slurries (Every and Jacob, 1978; Detroit, 1980). However, they are also retarders and cannot be used at low temperatures. It is important to note that the performance of some lignosulfonates, notably those containing large quantities of sugars, is very sensitive to cement quality, and gelation problems are possible. This can be attributed to a dramatic acceleration of interstitial-phase (C₃A and C₄AF) hydration (Michaux and Nelson, 1992). A modified lignosulfonate, with a molecular weight in the range of 60,000 to 120,000, has been patented as a biodegradable dispersant for offshore applications (Chatterji et al., 2000). The chemical structure of a modified lignosulfonate is shown in Fig. 3-20.

![Figure 3-20. Chemical structure of modified lignosulfonate.](image)

Polynaphthalene sulfonate (PNS) is by far the most common and cost-effective dispersant for well cements. However, it can no longer be used in some marine environments owing to its toxicity to algae, its tendency to bioaccumulate, and its nonbiodegradability in seawater. PNS is produced from naphthalene by sulfonation followed by polymerization with formaldehyde (Tucker, 1938). Residual sulfonic acid is neutralized with sodium hydroxide or lime. PNS is available in a wide variety of molecular weights and degrees of branching (Rixom, 1974; Costa et al., 1982). The repeating unit has the structure shown in Fig. 3-21. The value of n is typically low (about 10–20), but conditions are chosen to get a proportion of higher-molecular-weight product [molecular weight (MW) = 100,000], because it is believed to be more effective. The commercial material is supplied as a powder or a 40% aqueous solution. For freshwater slurries, 0.2–1.0% active PNS BWOC is normally required for effective slurry dispersion; however, as shown in Fig. 3-22, concentrations as high as 4% BWOC may be necessary for slurries containing NaCl (Michaux and Oberste-Padtberg, 1986). PNS can be used at temperatures as high as 400°F [204°C]. As shown in Fig. 3-23,
PNS concentration required to decrease the yield value of a cement slurry below 10 lbf/100 ft\(^2\) [4.8 Pa] varies depending upon the cement source (Michaux et al., 1986).

Polymelamine sulfonate (PMS) is frequently used in the construction industry (Malhotra and Melanka, 1979) but to a limited extent in well cementing, probably because it is significantly more expensive than PNS. Melamine reacts with formaldehyde to form trimethylol melamine, which is in turn sulfonated with bisulfite and condensed to form a polymer. The structure of the base unit is shown in Fig. 3-21. The polymerization time influences the MW of the product. The most useful average MW is about 30,000. The product is available commercially in solid form or as a water solution (20% and 40%). As shown in Fig. 3-24, about 0.4% PMS (BWOC) is typically required to achieve proper dispersion; however, as observed with PNS (Fig. 3-23), this concentration varies from cement to cement. This product is effective at temperatures up to about 250°F [121°C].

Other sulfonated polymers used as dispersants include polystyrene sulfonate (PSS) and a condensation product of aldehyde and ketone that contains sulfonate groups. PSS is an effective cement dispersant, but it is rarely used because of cost (Biagini, 1982). Its chemical structure is shown in Fig. 3-25.

The MW of the aldehyde/ketone condensation is approximately 15,000, and the dispersant is reported to be salt tolerant (Aignesberger and Plank, 1989). It is commercially available as a powder or a 33% aqueous solution.
Polycarboxylate-based products were developed more recently than PNS and PMS. They are now extensively used in the construction industry and are beginning to be used for well cementing, notably at low temperatures (Volpert, 2002). The polymer structure is generally composed of a backbone chain with carboxylic groups upon which polyethyleneoxide (PEO) side chains are grafted. Sulfonate groups can also be present on the backbone chain (Fig. 3-26). These polymers are sometimes called “comb polymers.” They are manufactured from the monomers by a free-radical mechanism using peroxide initiators and, depending on the degree of prepolymerization, can be either block or random polymers.

3-7.2 Effect of dispersants on the rheology of cement slurries

The rheological behavior of well cement slurries can be studied using a rotational viscometer, which enables determination of the yield value and plastic viscosity (Chapter 4; Appendix B). This is accomplished by plotting the shear stress against the shear rate. Figure 3-27 shows shear stress/shear rate plots for neat and dispersed cement slurries. The curves are approximately linear. The slope of the line is the plastic viscosity, and its ordinate at the origin is the yield value.

When the cement powder and water are mixed, a structure forms throughout the slurry owing to coagulation, which prevents flow below a given shear stress threshold, the yield value. At low shear stresses, below the yield value, the slurry behaves as a solid and does not flow. Above the yield value, it behaves as a liquid with a well-defined plastic viscosity. As shown in Fig. 3-28, cement dispersants reduce both the yield value and plastic viscosity. At high concentrations, the yield value approaches zero and the cement slurry becomes essentially Newtonian. Unfortunately, very low yield values often lead to slurry instability, resulting in solids sedimentation or free water.

When a solid with a characteristic net surface charge (such as a cement grain) is in contact with a solution, an electric double layer forms at the surface boundary. The inner layer, or Stern layer, which is approximately a single ion in thickness, consists of counterions that remain fixed to the solid surface. This is associated with a sharp fall in potential. The outer layer, or diffuse layer, extends some distance into the liquid phase. In this region, ionic species are free to move; however, because of the electrostatic field at the surface, there will be a preferential distribution of positive and negative ions. This results in a gradual decrease in potential towards the bulk solution, in which the charge distribution is uniform. The diffuse layer in highly ionic systems such as cement slurries is usually greatly compressed and typically only a few nanometers thick (Neubauer et al., 1998). The boundary between the Stern layer and the diffuse layer is called the shear plane. The electrical potential at the shear plane is known as the zeta potential or the electrokinetic potential. Dispersant molecules adsorbed at the surface of cement particles are positioned in the Stern layer and, therefore, contribute to the zeta potential. Figure 3-28 also shows how the zeta potential increases with PNS concentration. The zeta potential and cement dispersion are discussed later in this section.
3-7.3 Mechanisms of action

The dispersive effect of superplasticizers is caused by the adsorption of superplasticizer molecules on the surfaces of cement grains throughout the initial hydration reactions to the final set. Depending on the chemical structure of the dispersant, the effect is attributed to electrostatic repulsions, steric repulsions between cement grains, or both.

In the absence of dispersant, Portland cements contain about 80 wt% of calcium silicates, C₃S and C₂S (Chapter 2). During hydration, the surfaces of cement particles are mainly composed of silanol groups (–Si–OH). The silanol groups are hydrolyzed owing to the high pH (greater than 12.5) of the interstitial water.

\[
\text{–Si–OH + OH}^- \rightleftharpoons \text{–SiO}^- + \text{H}_2\text{O} \quad \text{(Eq. 3-2)}
\]

This should lead to electrostatic repulsion between the particles and to complete particle dispersion. However, the presence of calcium ions in the pore solution adds an attractive force. Calcium ions adsorb onto the negatively charged groups, conferring a global positive charge at the surface.

\[
\text{–Si – O}^- + \text{Ca}^{2+} \rightleftharpoons \text{–Si–O–Ca}^+ \quad \text{(Eq. 3-3)}
\]

One calcium ion may bind two hydrolyzed silanol groups. As shown in Fig. 3-29, the silanol groups may be on the same grain or bridging two grains (Thomas and Double, 1981). It must be kept in mind that the positive charge on a cement particle in a neat slurry is a global or average charge. The surface of hydrating cement is likely composed of positive patches separated by neutral or even possibly negative regions (Michaux and Défossé, 1986). Therefore, the particles tend to align with positive or negative patches. The resulting attractive forces create a three-dimensional structure. The strength of this structure is measured macroscopically by the yield value.

To properly describe the interactions between the cement grains, one must also take ion-correlation forces into account. For monovalent ions such as sodium, the effective double layer repulsion is only slightly reduced. For divalent ions such as calcium, the ion-correlation attraction exceeds the repulsive forces between the charged surfaces (Israelachvili, 1992). The different effects of sodium and calcium ions on interparticle forces have been observed experimentally by atomic force microscopy (AFM). The predominant attractive force between the cement particles in the presence of calcium ions creates a structural network between the particles. This explains why a neat, nondispersed cement slurry has a yield stress (yield value) and does not behave as a Newtonian fluid. Cement particles are aggregated because of the coagulation process induced...
by calcium ions. These aggregates contain entrapped interstitial water, which is not available to lubricate the cement grains when the cement slurry is being pumped. Thus, large cement particle aggregates correspond to high slurry viscosity.

In the presence of dispersant, adding an anionic polyelectrolyte such as polynaphthalene sulfonate or poly-melamine sulfonate can reduce the yield value and plastic viscosity of cement slurries. In theory, cationic polyelectrolytes could also be used for this purpose; however, they could react with anionic cement additives (e.g., retarders and fluid-loss additives) and cause performance difficulties. In addition, it is possible that the competition between the cationic polyelectrolyte and the calcium ions at the cement surface could impair the cement-hydration process.

Cement-slurry dispersion is achieved by adsorption of the dispersant molecules onto the cement-particle and hydration-product surfaces. The adsorption mechanism is still not clearly understood and may depend on the chemical structure of the dispersant. It is generally believed that the adsorption is caused by ionic bonds between calcium ions that are chemically adsorbed at the cement surface and the anionic groups (carboxylate or sulfonate) of the dispersant. The hydrophobic portion of the dispersant molecule may also preferentially adsorb onto cement-grain surfaces (Uchikawa et al., 1992).

A number of researchers have attempted to correlate dispersant adsorption with cement-slurry rheology and the zeta potential of cement particles. Michaux and Defossé (1986) performed such a study with Class G cement. To determine the amount of dispersant adsorbed onto hydrating cement particles, one measures the concentration of dispersant in the cement-pore solution and subtracts this value from the amount of dispersant originally added. Pore solutions are extracted from the cement slurry by filtration, and the dispersant concentration is determined by appropriate analytical techniques (e.g., ultraviolet spectroscopy for PNS and PMS). Figure 3-30 shows an adsorption isotherm for PNS in a cement slurry. The amount of adsorbed PNS varies with its concentration in the interstitial water, and the hydrating cement surfaces become saturated when a sufficient amount of PNS is present. When the cement-particle surfaces are saturated, any additional PNS remains in the pore solution. As hydration continues, the excess PNS can adsorb onto newly formed hydration-product surfaces. Adding extra dispersant can help reduce the loss of slurry fluidity that may occur as hydration progresses; however, overdosing can result in slurry sedimentation and free-water development.

There is considerable controversy between researchers concerning the validity of zeta-potential measurements on cement systems. Questions generally arise about dilution factors, sample preparation, and measurement methods. Common methods to measure the zeta potential, such as electrophoresis or streaming potential, require a low particle concentration in the test fluid—much lower than that in a cement slurry. The

![Figure 3-30. Adsorption isotherm and zeta potential for a diluted cement suspension (at 77°F (25°C)).](image-url)
The zeta potential of cement particles depends on many parameters that can vary significantly with the water-to-cement ratio. The most important parameters include the calcium concentration, alkali concentrations, pH, and nature and amount of hydration products. Hence, such methods have only a limited value for understanding the surface potential in a concentrated particle suspension like a cement slurry.

The only way to reliably measure the zeta potential in a concentrated particle suspension, with a solid-to-liquid weight ratio as low as 0.3, is to use the electrokinetic sonic amplitude method. Charged particles exposed to an alternating electric field in a solution generate sound waves. The instrument detects the sound waves and determines the dynamic mobility of the particles, from which the zeta potential is calculated. Using this technique, Uchikawa et al. (1997) measured a surface potential of $-1.8$ mV for a nondispersed cement slurry and $-11$ mV for a slurry containing 0.6% BWOC PNS.

The time at which the zeta potential is determined is also an important parameter. Indeed, the electrical double layer around the cement particles is not in equilibrium (Nägele, 1985, 1986, 1987; Hodne and Saasen, 2000). This is owing to the continuous production of ions at the interfaces between unhydrated cement surfaces and hydration products. In addition, owing to the formation of new hydration products, the surface composition varies continuously with time.

Figure 3-30 shows that the zeta potential increases when PNS is added to a cement slurry. This increase occurs because many of the anionic groups on the PNS molecules are not involved in the adsorption process. As a result, as schematically shown in Fig. 3-31, an adsorbed polyanionic molecule creates several negative charges. Clearly, when the cement-grain surfaces become saturated with dispersant molecules, no additional surface charge can be accommodated and the zeta potential levels off. The cement grains are negatively charged and repel each other because of repulsive electrostatic interactions.

Figure 3-28 shows that, at various PNS concentrations, there is a good correlation between the zeta potential, the rheological properties (yield value and plastic viscosity), and the free water. When the zeta potential reaches a maximum negative value, corresponding to the saturation of the hydrated cement surface by dispersant molecules, the yield value drops to zero. The plastic viscosity tends toward a minimum value owing to the deflocculation of cement aggregates. Thus, the effective volume of solids in the suspension is decreased, and the cement fluidity improves. With further addition of PNS, the free water increases dramatically because the cement particles are now free to sediment according to Stokes law. Such cement slurries are considered overdispersed.

When particles covered with a layer of adsorbed polymer approach one another, a repulsive force can be induced when the layers overlap (Fig. 3-32). It is likely that, for cement dispersants with a bulky structure, this steric hindrance effect occurs in addition to electrostatic repulsion.

Polycarboxylate dispersants are often comb polymers with grafted polyethylene oxide [(OCH$_2$CH$_2$)$_n$, PEO] side chains. In the concrete industry, such polymers are among the most efficient superplasticizers. The polymer backbone consists of carboxylic groups and, sometimes, sulfonate groups. Adsorption of these polymers onto the hydrating cement grains probably occurs by way of the carboxylic groups. When the polymer is adsorbed onto a cement particle, a portion of the grafted side chains is oriented into the solution. In a good solvent such as water, solvent-chain interactions are energeti-
cally favored over chain-chain contacts. For the above-mentioned comb polymers, the PEO side chains interact favorably with the aqueous medium and can stretch into the solution. As cement particles approach each other and the adsorbed layers of dispersant begin to overlap, a local increase in osmotic pressure occurs. The increased osmotic pressure induces a steric repulsive force between the cement particles, resulting in dispersion. For polycarboxylate dispersants, steric repulsion can be more important than electrostatic repulsion (Uchikawa et al., 1997; Yoshioka et al., 1997). Calculated interparticle potentials indicate that, because of the high concentration of electrolytes in cement pore solution (up to 1 M), the repulsive electrostatic forces generated by the polycarboxylates are never capable of overcoming the attractive Van der Waals forces (Flatt and Bowen, 2003). For this reason, the steric hindrance between the adsorbed layers of polymer must be the principal contributor to the dispersion mechanism.

3-7.4 Factors affecting the response of cements to dispersants

The concentration of dispersant required to effectively disperse a cement slurry varies considerably from cement to cement. This is clearly illustrated in Fig. 3-23, which shows the response of several cements that conform to the API/ISO Class G specification. The PNS concentration necessary to achieve full dispersion (yield value close to zero) varies from about 0.2% to 0.6% BWOC. Many cement properties can affect the performance of dispersants:

- cement fineness
- nature and amount of calcium sulfates
- nature and amount of soluble alkali sulfates
- C\textsubscript{3}A content
- distribution of aluminate and silicate phases at the cement-grain surfaces (Vidick et al., 1987)
- reactivity of the cement phases (particularly C\textsubscript{3}A and C\textsubscript{4}AF) (Michaux and Nelson, 1992)
- cement aging (carbonation and prehydration of anhydrous cement).

In general, the amount of dispersant required to attain a given level of dispersion increases with the fineness of the cement. The number of adsorption sites on the cement particles increases exponentially as the particle size decreases.

The initial aluminate and silicate hydrates form around the cement grains during the preinduction period. The hydration of the interstitial phase (C\textsubscript{3}A and C\textsubscript{4}AF) during this period is the most important parameter affecting the slurry rheology. Several studies have shown that interstitial-phase hydration products adsorb much greater amounts of dispersant than silicate-phase hydration products (Uchikawa et al., 1992; Yoshioka et al., 2002). This effect is more pronounced with PNS and PMS than the polycarboxylate dispersants (Uchikawa et al., 1995). C\textsubscript{3}A is much more reactive than C\textsubscript{4}AF, especially at early hydration times. Thus, the amount of dispersant required to obtain a given level of dispersion increases with the C\textsubscript{3}A content.

As described in Chapter 2, sulfate compounds in Portland cement control the interstitial-phase hydration. These include the alkali sulfates (Na\textsubscript{2}SO\textsubscript{4}, K\textsubscript{2}SO\textsubscript{4}, and NaKSO\textsubscript{4}) and the calcium sulfates [CaSO\textsubscript{4} • 2H\textsubscript{2}O (gypsum), CaSO\textsubscript{4} • 1/2H\textsubscript{2}O (plaster), CaSO\textsubscript{4} (anhydrite), and CaK\textsubscript{2}(SO\textsubscript{4})\textsubscript{2} (syngenite)]. The alkali sulfates are very soluble and readily go into solution when the cement powder is added to water. The solubility and dissolution rates of the calcium sulfates are much lower (plaster > gypsum > anhydrite) and can be altered by the presence of organic compounds. The nature and the amount of sulfate compounds in Portland cement strongly affect the behavior and efficiency of cement dispersants.

- For all types of dispersants, the initial cement-slurry fluidity increases with the solubility of the calcium sulfates (Moulin and Broyer, 2003). However, the physico-chemical parameters governing longer-term cement-slurry fluidity are more complex.
- Cement-dispersant efficiency is low when anhydrite is the principal calcium-sulfate phase (Prince et al., 2003). The low dissolution rate of anhydrite inhibits ettringite formation; consequently, the interstitial-phase hydration rate is high.
- PNS is more effective with cements that contain gypsum as the principal calcium-sulfate phase (Basile, 1987), rather than plaster or anhydrite.
- Sodium sulfate competes with PNS for adsorption sites during early hydration (Kim et al., 2000; Chandra and Björnström, 2002a and 2002b). This contributes to longer-term cement-slurry fluidity, because more PNS is left in the aqueous phase to adsorb onto future hydration products. Jiang et al. (1999) determined that, for most dispersants and cement compositions, the optimal dispersant concentration (expressed as %Na\textsubscript{2}O) is 0.4–0.5% BWOC.

The performance of dispersants can also be influenced by other physical and chemical factors.

- nature and concentration of salts present or added to the mix water (Section 3.7.1)
- mixing energy and mixing method
- mix-water temperature
- water-to-cement ratio
when the dispersant is added [introduced in the mix water or added after cement is mixed with water (post-added)]

- chemical structure of the dispersant (e.g., MW, linear or branched polymer and steric size) (Section 3.7.1).

The slurry mixing conditions have a strong effect on the behavior of dispersed slurries. High mixing energy and long mixing times increase the amount of hydrates formed during the preinduction period. As a result, a greater amount of dispersant is consumed. The efficiency of dispersants is also inversely related to the mix-water temperature.

When the dispersant is present in the mix water during the preinduction period, a portion is consumed by the initial hydration products and is no longer available to perform its intended function. Numerous studies have demonstrated that dispersants are more efficient when they are post-added to a cement slurry (Michaux et al., 1986; Michaux and Nelson, 1992; Collepardi et al., 1980; Chiocchio and Paolini, 1985). This effect is particularly strong with PMS and PNS (Uchikawa et al., 1995; Hanehara and Yamada, 1999). Delayed addition ensures that all of the dispersant is available to adsorb onto cement particles and hydration products. Experimental studies have shown that the optimal delay time is between 1 and 5 min after initial slurry mixing. As shown in Fig. 3-33, delaying the addition of PNS to a Class G cement slurry significantly improves the dispersant efficiency.

### 3-7.5 Particle settling and free water

As a side effect of dispersant addition, the slurry may show sedimentation (a slurry-density gradient from the top to the bottom of a container resulting from particle settling), free water (a layer of nonparticle-laden fluid on top of the slurry), or both. Free water (also called free fluid) can occur with a homogeneous slurry below. Sedimentation can occur without forming a separate water layer.

- **Free water**: When the cement particles are not completely dispersed, they interact through electrostatic forces. A flocculated structure forms and supports the weight of a given particle. If the annulus in the well is sufficiently narrow, the weight of the particles is transmitted to the walls, and the slurry is self-supporting. Such cases are rare; normally, the weight of the cement particles is transmitted to the bottom by the gel lattice, and structural deformation occurs. Water is squeezed out of the lower portion of the slurry and is accommodated in the higher, less-stressed layers. The ability of the upper layers to accommodate the additional water is limited; thus, a layer of water may form at the top of the slurry (Fig. 3-34).

- **Sedimentation**: As described in the previous sections, dispersants suppress the interactions between cement particles by neutralizing positively charged sites. When the process is complete, the particles repel each other through double-layer interactions. The range of action of these forces is a very short distance owing to the high ionic content of the aqueous phase. Therefore, the repulsive forces allow smooth particle packing. In a fully dispersed slurry, the parti-
icles are free to fall and collect at the container bottom. In reality, this ideal situation never occurs; instead, a density gradient forms. Three explanations may be proposed that incorporate the concept of particle polydispersity, that is, that small and large particles do not behave identically.

1. Smaller particles have not settled yet.
2. Brownian motion prevents small-particle settling.
3. A flocculated gel exists but is not sufficiently strong to support the larger particles.

3-7.6 Prevention of free water and slurry sedimentation

Nonhomogeneous cement columns are not acceptable, particularly when the wellbore is highly deviated or horizontal (Chapters 12 and 13). Sufficient set-cement strength and zonal isolation are jeopardized under such circumstances. Careful study of Fig. 3-28, a plot of free water and yield value versus PNS dispersant concentration, reveals a narrow range (0.2–0.3 wt% BWOC) within which the slurry is sufficiently fluid and yet stable. In a field environment, it is difficult to control additive concentrations within such a narrow range. Therefore, anti-settling agents are often added to broaden the concentration range within which low yield values and low free water can be obtained (Fig. 3-35). Antisettling agents are materials that restore some of the yield value but at a level compatible with the pumping conditions and friction pressure the exposed formation can bear. Examples of such materials are discussed below.

Bentonite may be used to reduce slurry settling (Morgan and Dumbauld, 1954). As discussed in Section 3-5, bentonite has the ability to absorb large quantities of water; as a result, slurry homogeneity is preserved.

Various hydrosoluble polymers reduce sedimentation by increasing the interstitial-water viscosity. The most commonly used materials are cellulosic derivatives such as hydroxyethylcellulose (HEC) and welan gum (Allen et al., 1991; Skaggs et al., 2001).

Seawater and silicates can improve slurry stability (Childs et al., 1984). In addition, metallic salts such as NiCl₂ and MgCl₂ build weak but extensive hydroxide structures throughout the slurry (Defossé, 1985a; Kar, 1986). As shown in Fig. 3-36, such structure building substantially reduces free water.

Figure 3-35. Yield-value and free-water behavior of 15.8-lbm/gal [1,900-kg/m³] Class G cement slurries with and without antisettling agent at 185°F (85°C).

Figure 3-36. Free water development of 15.8-lbm/gal [1,900 kg/m³] Class G slurries with two PNS dispersant concentrations [185°F (85°C)].
The efficiency of antisettling additives can be evaluated by measuring the density gradient in a column of set cement (Appendix B). A test slurry is placed in a cylinder and allowed to set. Wafers of the set cement are sliced from the top, middle, and bottom of the column. The weight difference between the wafers gives an indication of the extent of slurry sedimentation. Figure 3-37 illustrates typical results for two 15.8-lbm/gal [1.9 g/cm³] slurries.

3-8 Fluid-loss control agents

When a cement slurry is placed across a permeable formation under pressure, a filtration process occurs. The aqueous phase of the slurry escapes into the formation, leaving the cement particles behind. Such a process is commonly known as fluid loss and is described in detail in Chapter 6.

If fluid loss is not controlled, several serious consequences may result that can lead to cement-job failure. As the volume of the aqueous phase decreases, the slurry density increases; as a result, the slurry performance diverges from the original design. If sufficient fluid is lost to the formation, the slurry becomes unpumpable.

The API fluid-loss rate of a neat cement slurry (Appendix B) generally exceeds 1,500 mL/30 min. As discussed in Chapter 6, an API fluid-loss rate less than 50 mL/30 min is often required to maintain adequate slurry performance. To accomplish such a reduction in the fluid-loss rate, materials known as fluid-loss control agents are included in the slurry design.

The exact mechanisms by which fluid-loss control agents operate are not completely understood; however, several processes are known to occur. Once fluid loss commences across a formation, a filtercake of cement solids is deposited on the formation surface. Fluid-loss agents decrease the filtration rate by reducing the filtercake permeability, increasing the viscosity of the aqueous phase, or both.

Two principal classes of fluid-loss additives exist: finely divided particulate materials and water-soluble polymers. The chemical and physical nature of each type of material, as well as mechanistic hypotheses, is discussed in this section.

3-8.1 Particulate materials

The first fluid-loss control agent used for cement slurries was bentonite. Because of the small size of its platelets (Section 3-3), bentonite can enter the filtercake and lodge between the cement particles, decreasing the permeability of the filtercake. In addition to bentonite, particulate systems such as carbonate powder, carbon black, microsilica, asphaltenes, and thermoplastic resins are used to control fluid loss.

As described in Chapter 7, latex cements demonstrate excellent fluid-loss control. Latexes are emulsion polymers, usually supplied as milky suspensions of very small spherical polymer particles (generally between 30 and 200 nm in diameter). Most latex dispersions contain about 45% solids. Like bentonite, such small particles physically plug small pores in the cement filtercake.

The most common latexes for well cements are those of vinylidene chloride (Eberhard and Park, 1958), polyvinyl acetate (Woodard and Merkle, 1964), and styrene-butadiene (Parcevaux et al., 1985). The first two materials are limited to temperatures below 122°F [50°C]. Styrene-butadiene latex has been applied at temperatures up to 375°F [191°C]. Figure 3-38 is a plot of fluid-loss rate versus styrene-butadiene-latex concentration for various cement slurries.

A newer particulate fluid-loss additive, based on crosslinked polyvinyl alcohol (PVA) microgels, was introduced by Audebert et al. in 1997. It provides excellent fluid-loss control at temperatures up to 250°F [121°C] (Fig. 3-39). This additive does not retard cement hydration and is compatible with cement accelerators. Thus, it is particularly suitable for low-temperature applications, for which short waiting-on-cement times are difficult to obtain. Crosslinked PVA can also be used in combination with polyvinylpyrrolidone (Moulin, 2001). Cement slurries prepared with this additive combination show excellent gas-tight properties. Such additives can be used in combination with microcement and other chemicals for squeeze cementing during which a high degree of fluid-loss control is often required (Barlet-Gouédard et al., 2001; Chapter 14).
Figure 3-38. Fluid-loss behavior of latex-modified cement slurries at 185°F [85°C].

Figure 3-39. Fluid-loss behavior of Class G cement slurry containing crosslinked PVA fluid-loss additive at various temperatures.
The fluid-loss behavior of cement slurries containing particulate fluid-loss additives is different from that observed when employing water-soluble polymers. The leakoff is not a function of the square root of time. Instead, an initial filtrate spurt occurs that corresponds to the formation of a thin filtercake. Then the fluid-loss rate is very low, owing to the low filtercake permeability.

### 3-8.2 Water-soluble polymers

Water-soluble polymers received much attention as fluid-loss control agents in the early 1940s, when they were first used in drilling fluids. Today, such materials are used extensively as fluid-loss control agents for well cement slurries. In general terms, they operate by simultaneously increasing the viscosity of the aqueous phase and decreasing the filtercake permeability.

![Figure 3-40. Concentration and molecular-weight effect on viscosity of aqueous solutions of HEC at 77°F [25°C].](image1)

![Figure 3-41. Pore diameters of two Class G cement filtercakes (15.8 lbm/gal [1,900 kg/m³], with 0.5% PNS BWOC, no fluid-loss additive).](image2)

### Table 3-15. Efficiency of Different Polymers in Decreasing Cement Filtercake Permeability and Increasing Filtrate Viscosity at 80°F [25°C]†

<table>
<thead>
<tr>
<th>Additive</th>
<th>Filtercake Permeability (mD)</th>
<th>Viscosity of the Filtrate (cp)</th>
<th>Efficiency Ratio</th>
<th>Fluid-Loss Volume (mL/30 min)</th>
</tr>
</thead>
<tbody>
<tr>
<td>None</td>
<td>5,100</td>
<td>1</td>
<td>1</td>
<td>1,600</td>
</tr>
<tr>
<td>A–0.35% BWOC</td>
<td>924</td>
<td>2.24</td>
<td>0.280</td>
<td>450</td>
</tr>
<tr>
<td>A–0.60% BWOC</td>
<td>140</td>
<td>4.48</td>
<td>0.077</td>
<td>173</td>
</tr>
<tr>
<td>A–0.80% BWOC</td>
<td>6.1</td>
<td>3.70</td>
<td>0.018</td>
<td>45</td>
</tr>
<tr>
<td>A–1.00% BWOC</td>
<td>4.9</td>
<td>3.32</td>
<td>0.017</td>
<td>20</td>
</tr>
<tr>
<td>B–0.30% BWOC</td>
<td>770</td>
<td>3.10</td>
<td>0.217</td>
<td>300</td>
</tr>
<tr>
<td>B–0.80% BWOC</td>
<td>5.1</td>
<td>4.80</td>
<td>0.014</td>
<td>26</td>
</tr>
<tr>
<td>B–1.30% BWOC</td>
<td>1.3</td>
<td>2.30</td>
<td>0.011</td>
<td>12</td>
</tr>
<tr>
<td>C–0.08 gal/sk</td>
<td>1,825</td>
<td>1.01</td>
<td>0.596</td>
<td>240</td>
</tr>
<tr>
<td>C–0.20 gal/sk</td>
<td>21</td>
<td>1.05</td>
<td>0.058</td>
<td>43</td>
</tr>
<tr>
<td>C–0.40 gal/sk</td>
<td>15</td>
<td>2.05</td>
<td>0.038</td>
<td>14</td>
</tr>
</tbody>
</table>

† From Desbrères, 1988
The viscosity of a polymer solution is dependent upon the concentration and the MW. For example, as seen in Fig. 3-40, a 2 wt% solution of low-molecular-weight HEC may have a viscosity of 500 cp, but the viscosity of an equally concentrated solution of high-molecular-weight HEC can be as high as 50,000 cp. Such a high viscosity would certainly decrease the filtration rate; however, this strategy alone cannot be relied upon to provide fluid-loss control, because slurry mixing would be impossible.

Reduction of filtercake permeability is the more important parameter for fluid-loss control. When a slurry contains sufficient fluid-loss control agent to provide an API/ISO fluid-loss rate of 25 mL/30 min, the resulting filtercake is approximately 1,000 times less permeable than that obtained with a neat slurry (Binkley et al., 1958; Desbrières, 1988). In this case, the interstitial water viscosity increases, at most, five times (Table 3-15).

The size of the pores in the cement filtercake can be evaluated by mercury porosimetry. The typical size distribution is shown in Fig. 3-41, which shows the median diameter to be 1 μm. The typical radius of gyration of a polymer molecule is less than 1,000 Å (0.1 μm); therefore, only clusters of molecules would be sufficiently large to obstruct a pore in the filtercake. Water-soluble polymers can form weakly bonded colloidal aggregates in solution that are sufficiently stable to become wedged in the filtercake constrictions (Christian et al., 1976). Such polymers may also adsorb onto the cement grain surfaces and thus reduce the pore size. More likely, a superposition of these two phenomena, adsorption plus aggregation, is the true mechanism of action of polymeric fluid-loss agents.

Cement slurries containing water-soluble polymers must be well dispersed to obtain optimal fluid-loss control. Sulfonated aromatic polymers or salts are almost always added with these materials. As described in Section 3-7, dispersants improve the packing of cement grains (and perhaps the polymer aggregates) in the filtercake. Thus, as shown in Table 3-16, dispersants reduce the permeability of the cement filtercake and can provide some degree of fluid-loss control on their own (Smith, 1987). However, one must bear in mind that slurry overdispersion and sedimentation may artificially improve the results of the API/ISO fluid-loss test (Appendix B).

Unlike particulate fluid-loss additives, water-soluble polymers do not promote the formation of a thin and impermeable cement filtercake. Instead, they simply reduce the rate at which the filtercake thickens. This process continues until the slurry dehydrates, leaving a thick filtercake.

Several classes of water-soluble polymers are used as fluid-loss control agents. The chemical properties and performance of each are discussed separately in the following sections.

### 3-8.2.1 Natural polymers

#### 3-8.2.1.1 Cellulose derivatives

The first fluid-loss additive based on a water-soluble polymer was a protein (i.e., a polypeptide) extracted from soybeans (Alcorn and Bond, 1949). Shortly thereafter, ethylene diamine carboxymethylcellulose and other cellulose derivatives were introduced. In the late

---

**Table 3-16. API/ISO Fluid-Loss Rates of Densified Slurries of Classes A and G Cement with a 325-Mesh Screen, 1,000 psi Pressure, and Temperature of 80°F**

<table>
<thead>
<tr>
<th>PNS Dispersant (%)</th>
<th>Fluid Loss (mL/30 min) at a Water Ratio (gal/sk) of 3.78</th>
<th>4.24</th>
<th>4.75</th>
<th>5.2</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.50</td>
<td>490</td>
<td>504</td>
<td>580</td>
<td>690</td>
</tr>
<tr>
<td>0.75</td>
<td>310</td>
<td>368</td>
<td>476</td>
<td>530</td>
</tr>
<tr>
<td>1.00</td>
<td>174</td>
<td>208</td>
<td>222</td>
<td>286</td>
</tr>
<tr>
<td>1.25</td>
<td>118</td>
<td>130</td>
<td>146</td>
<td>224</td>
</tr>
<tr>
<td>1.50</td>
<td>72</td>
<td>80</td>
<td>92</td>
<td>–</td>
</tr>
<tr>
<td>1.75</td>
<td>50</td>
<td>54</td>
<td>64</td>
<td>–</td>
</tr>
<tr>
<td>2.00</td>
<td>36</td>
<td>40</td>
<td>48</td>
<td>–</td>
</tr>
</tbody>
</table>

1 From Smith, 1987.
2 Not available

---

**Figure 3-42. Idealized molecular structure of HEC.**
1950s, CMHEC was introduced as a fluid-loss additive for cement slurries (Shell and Wynn, 1958; Greminger, 1958). The basic unit structure of CMHEC is shown in Fig. 3-9.

More recently, the performance of CMHEC has been improved by adjusting the DS from 0.1 to 0.7 (carboxymethyl) and the mole ratio of ethylene oxide to anhydroglucose (by MS) from about 0.7 to about 2.5 (Fig. 3-9) (Chatterji and Brake, 1982; Chatterji et al., 1984). According to Chatterji et al. (1984) the performance of CMHEC in salt slurries can be improved by adding a hydroxycarboxy acid such as tartaric acid.

The most common cellulosic fluid-loss control agent is HEC, with a DS range between 0.25 and 2.5 (Hook, 1969). The basic structural unit is shown in Fig. 3-42. Various MWs of the polymer are used, depending upon the density of the cement slurry. For normal-density slurries, an HEC of medium MW (2% solution viscosity: 40 cp) is used. The typical fluid-loss-control performance of this material is shown in Fig. 3-43. A higher-molecular-weight HEC is used for lower-density slurries (2% solution viscosity: 180 cp), and the typical performance in bentonite-extended slurries is shown in Fig. 3-44.

HEC, as well as hydroxypropyl cellulose (HPC), with a DS range of about 0.9 to 2.8 and a MS range of about 1.0 to 6.0, are disclosed as fluid-loss control additives when used with high-molecular-weight xanthan gum (MW 2,000,000) (Baker and Harrison, 1984).

Cellulosic fluid-loss additives generally share certain disadvantages. They are effective water viscosifiers; as a result, they can increase the difficulty of slurry mixing and ultimately cause undesirable cement-slurry viscosification. At temperatures less than about 150°F [65°C], cellulosic fluid-loss additives are efficient retarders; thus, care must be taken to avoid slurry overretardation. Also, as shown in Fig. 3-43, the efficiency of the cellulose polymers decreases with increasing temperature.

Recent changes in environmental regulations around the world have encouraged the development of more environmentally acceptable cement additives. Biopolymers such as cellulosics are very attractive because they pose little or no risk to the environment. Therefore, work has been performed to extend the useful range of cellulosic fluid-loss additives.

Mueller and Bray (1993) found that adding ethoxylate-coated resins in concert with HEC (and also PVA) significantly improved fluid-loss performance. Greater efficiency, salt tolerance, and thermal stability were reported.

A low-molecular-weight ethoxylated HEC (MW = 60,000), with 1 to 4 moles of ethylene oxide per anhydroglucose unit, was recently introduced (Dao and Vijn, 2002; Vijn et al., 2002). It is effective at temperatures up to 280°F [138°C] and can be used in cement slurries prepared with fresh water, seawater, or salt-saturated mix water. A temperature-stabilizing agent, such as synthetic hectorite [Na0.4Mg2.7Li0.3Si4O10(OH)2], sodium thiosulphate, or magnesium oxide, can also be added.

### 3.8.2.1.2 Galactomannans

Galactomannans are natural polysaccharides essentially consisting of galactose and mannose units (Fig. 3-45). They are produced from the endosperm of leguminous seeds such as guar or carob. Guar gum is a polymer that contains monomeric units of D-mannose linked to one another by 1–4 bonds forming the main chain on which units of D-galactose are branched by 1–6 bonds. In the oil field, guar and guar derivatives have been used for many years to viscosify hydraulic fracturing fluids.

A hydrophobically modified hydroxypropylated guar (HPG), with a MW of less than 2,000,000, can provide fluid-loss control at temperatures up to about 230°F [110°C] (Audibert et al., 2001).
3-8.2 Synthetic polymers

3-8.2.2 Nonionic synthetic polymers

Polyvinylpyrrolidone (PVP) may be used with PNS dispersants (Boncan and Gandy, 1986). It is also known to improve fluid-loss control when added with CMHEC (Hale, 1981) or HEC (Chatterji and Brake, 1982; Chatterji, et al., 1984).

Complex mixtures containing polyvinylpyrrolidone, maleic anhydride-N-vinylpyrrolidone copolymer, and poly(aryl-vinylbenzyl) ammonium chloride, i.e., polyca-
tions (Wahl and Dever, 1963), have been reported as effective fluid-loss control additives. In addition, N-vinylpyrrolidone can be copolymerized with styrene sulfonate (SS) to form an effective fluid-loss control additive (Newlove et al., 1984; Sedillo et al., 1987).

PVA is frequently used as a fluid-loss control additive (Harrison, 1968; Carpenter, 1986; Moran and Moran, 1998a and 1998b). This material is particularly advantageous for low-temperature applications [less than 100°F (38°C)] because it has no retarding effect and is compatible with accelerators such as calcium chloride. The fluid-loss control behavior of PVA is shown in Fig. 3-46. It is important to note the sharp threshold effect associated with this additive. Within a very short concentration range, the fluid-loss rate falls from 500 mL/30 min to less than 20 mL/30 min. Therefore, to ensure adequate fluid-loss control, special care is necessary during field blending operations to verify the correct additive concentration. As discussed in Section 3-8.1, PVA can be crosslinked to form a microgel that is not water soluble.
3-8.2.2.2 Anionic synthetic polymers

The largest group of anionic polymer fluid-loss additives is composed of co- or terpolymers derived from acrylamide (AAm). Polyacrylamides are nonionic and are not used by themselves as fluid-loss additives, although they can provide some fluid-loss control. They are subject to rapid hydrolysis to acrylic acid (AA), resulting in severe cement-slurry retardation (Crema et al., 1989).

Partially hydrolyzed polyacrylamide, containing various proportions of acrylic acid or acrylate units, is often added to drilling fluids. However, it is difficult to use in well-cement slurries owing to the strong interaction between the carboxylate groups and cement grain surfaces, often resulting in retardation or flocculation. Nevertheless, some applications have been reported using a material with a low AA/AAm ratio, about 0.1 (McKenzie and McElfresh, 1982).

The copolymers of AAm most often described in the patent literature contain a sulfonate monomer: 2-acrylamido-2-methyl propane sulfonic acid (AMPS) (Mueller, 1992). The structural formula is shown in Fig. 3-47. AMPS has been copolymerized with the following materials to produce fluid-loss control agents.

- AAm (Persinski et al., 1977; Boncan and Gandy, 1986; Oswald et al., 2001; Walker, 2002)
- N,N-dimethylacrylamide (NNDMA) (Rao and Burkharter, 1986; Brothers, 1987; George and Gerke, 1985; Fry et al., 1987; Chatterji et al., 2001).

Terpolymers of AMPS are also used, as listed below.
- AMPS + AAm + itaconic acid (IA) (Savoly et al., 1987)
- AMPS + AA + N-methyl-N-vinyl acetamide (NMVA) (Defossé, 1985)
- AMPS + vinyl sulfonate + NMVA (Hille et al., 1987)

![Figure 3-47. AMPS structure, polyethylene imine repeating structure and branching, and polyallylamine structure.](image)

![Figure 3-48. Typical fluid-loss-control performance of AMPS/N-vinyl-2-pyrrolidone/acrylamide/acrylic acid tetrapolymer versus temperature. The plot shows the fluid-loss additive concentration in a Class H cement necessary to achieve an API/ISO fluid-loss rate of less than 50 mL/30 min.](image)
AA(AAm) + NMV + AMPS (Hille et al., 1987)

AMPS may also be part of a copolymer or a terpolymer grafted to a lignin backbone and associated with acrylonitrile, NNDMA, or AA. These complex polymers are efficient in salt slurries (Fry et al., 1987).

A polymer composition comprising the random polymerization product of acryloylmorpholine with at least one and, preferably, two other monomers within the group consisting of AMPS, N-vinyl pyrrolidone, and vinylphosphonic acid, is effective to reduce fluid loss of cement slurries at temperatures up to 400°F [204°C] (Udarbe and Hancock-Grossi, 2000).

A tetrapolymer composed of AMPS, N-vinyl-2-pyrrolidone, AAm, and acrylic acid controls fluid loss of cement slurries at temperatures up to 450°F [232°C] (Stephens, 1994). Typical performance of this additive is illustrated in Fig. 3-48.

Copolymers containing AAm, 3-allyloxyhydroxypropanesulfonate, and other monomers are reported to exhibit excellent fluid-loss control properties at temperatures ranging from 80°F [27°C] to 350°F [177°C] (Bair et al., 2002). They are not salt sensitive and can tolerate a salt concentration up to saturation.

A tannin grafted with AMPS and AAm provides fluid-loss control at temperatures up to 400°F [204°C] (Huddleston et al., 1992). This polymer is also reported to prevent gas migration through the cement slurry (Eoff and Loughridge, 1994).
Sulfonated polyvinyl aromatics such as sulfonated polystyrene (SPS) (Martin, 1966; Newlove et al., 1984; Sedillo et al., 1987) and sulfonated polyvinyltoluene (SPVT) (Wahl et al., 1963) have been identified as useful fluid-loss control agents. A blend of SPVT, PNS, and a sulfonated copolymer of styrene and maleic anhydride is effective in salt cement systems (Nelson, 1986). The fluid-loss control performance of this material in a salt-saturated cement slurry is shown in Fig. 3-49.

3.8.2.2.3 Cationic synthetic polymers

Polyethylene imine (PEI), shown in Fig. 3-47, is an example of a polyalkylene polyamine that was widely used as fluid-loss additive (Gibson and Kucera, 1970; Scott et al., 1970; McKenzie, 1984). The MW range within which PEI is effective is 10,000 to 1,000,000. Its structure is likely to be highly branched; therefore, all three types of amine groups (primary, secondary, and tertiary) should be present in the chain.

The dispersant PNS must be present with PEI to obtain significant fluid-loss control. An insoluble association is made between the two polymers to create particles that provide fluid-loss control. As shown in Fig. 3-50, fluid-loss control improves as the MW of the PEI increases.

The principal advantage of PEI as a fluid-loss control agent is its effectiveness at high temperatures. As shown in Table 3-17, PEI provides excellent fluid-loss control at circulating temperatures as high as 436°F [225°C]. A notable disadvantage of PEI is its tendency to promote slurry sedimentation (Section 3-5). Although the sedimentation is preventable, slurry design can be very difficult.

Polyallylamine has been reported by Roark et al. (1986; 1987a, 1987b, and 1987c) as an effective fluid-loss control agent. Instead of being part of the chain backbone, the amine group is pendant (Fig. 3-47). This material can also be slightly crosslinked to decrease slurry sedimentation. Table 3-18 shows the fluid-loss control performance of polyallylamine at two MWs.

Various quaternary ammonium or sulfonium monomers can be copolymerized with other materials to obtain effective fluid-loss control agents. Several are listed below.

- Alkyl ammonium chloride or sulfonium chloride (Wahl and Dever, 1963)
- Dimethyl-diallyl ammonium chloride (DM-DAAC)

### Table 3-17. Typical Fluid-Loss Data from Cement Slurries Containing a Polyamine Fluid-Loss Additive†

<table>
<thead>
<tr>
<th>Fluid-Loss Additive (%BWOC)</th>
<th>PNS (%BWOC)</th>
<th>Ilmenite (lbm/sk)</th>
<th>Slurry Density (lbm/gal)</th>
<th>Temperature (°F)</th>
<th>Fluid-Loss (mL/30 min)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.1</td>
<td>0.5</td>
<td>–</td>
<td>16.2</td>
<td>290</td>
<td>20</td>
</tr>
<tr>
<td>0.1</td>
<td>0.5</td>
<td>–</td>
<td>16.2</td>
<td>315</td>
<td>30</td>
</tr>
<tr>
<td>0.13</td>
<td>0.5</td>
<td>–</td>
<td>16.2</td>
<td>337</td>
<td>18</td>
</tr>
<tr>
<td>0.15</td>
<td>1.0</td>
<td>–</td>
<td>16.8</td>
<td>299</td>
<td>8</td>
</tr>
<tr>
<td>0.15</td>
<td>1.5</td>
<td>–</td>
<td>19.0</td>
<td>380</td>
<td>34</td>
</tr>
<tr>
<td>0.15</td>
<td>1.5</td>
<td>–</td>
<td>20.0</td>
<td>370</td>
<td>40</td>
</tr>
<tr>
<td>0.18</td>
<td>1.0</td>
<td>5</td>
<td>17.4</td>
<td>342</td>
<td>30</td>
</tr>
<tr>
<td>0.18</td>
<td>1.0</td>
<td>30</td>
<td>18.2</td>
<td>370</td>
<td>90</td>
</tr>
<tr>
<td>0.18</td>
<td>1.0</td>
<td>25</td>
<td>18.0</td>
<td>400</td>
<td>78</td>
</tr>
<tr>
<td>0.2</td>
<td>1.2</td>
<td>95</td>
<td>19.2</td>
<td>436</td>
<td>16</td>
</tr>
<tr>
<td>0.25</td>
<td>1.5</td>
<td>70</td>
<td>19.0</td>
<td>380</td>
<td>10</td>
</tr>
<tr>
<td>0.25</td>
<td>1.5</td>
<td>70</td>
<td>19.0</td>
<td>380</td>
<td>11</td>
</tr>
</tbody>
</table>

† Fluid-loss tests were run with a differential pressure of 500 psi (750 psi with 250-psi backpressure).
‡ Not applicable

### Table 3-18. Comparison of Two MWs of Polyallylamine Polymers Added at 2% BWOC to 15.8-lbm/gal [1,897 kg/m³] Class G Cement†

<table>
<thead>
<tr>
<th>Molecular Weight</th>
<th>API Fluid Loss (mL/30 min)</th>
</tr>
</thead>
<tbody>
<tr>
<td>10,000</td>
<td>121</td>
</tr>
<tr>
<td>150,000</td>
<td>142</td>
</tr>
</tbody>
</table>

† (from Roark et al., 1987a, 1987b, and 1987c).
3-9 Lost-circulation prevention agents

The loss of circulation during a primary cementing job is a serious problem that often necessitates remedial cementing. Circulation losses tend to occur in vuggy or cavernous formations, particularly in highly fractured, incompetent zones that break down at relatively low hydrostatic pressures.

Usually, the operator will have experienced some circulation difficulties during drilling; thus, measures can be taken to prevent their occurrence during cementing. A thorough discussion of the causes of and solutions for lost circulation is presented in Chapter 6; however, in this chapter, it is appropriate to briefly mention the common cement additives used to prevent lost circulation.

3-9.1 Bridging materials

Many lost-circulation problems are controlled by the addition of materials that physically bridge over fractures and block weak zones. Such materials increase the resistance of the zone to pressure parting. As a general rule, they are chemically inert with respect to Portland cement hydration.

Granular materials such as gilsonite and granular coal are excellent bridging agents. As discussed in Section 3-5, they are also used extensively as cement extenders. They are added in concentrations similar to those specified in Section 3-5. Other granular materials used less often include ground walnut or pecan shells, Formica® chips (available in various particle sizes), coarse bentonite, and even corn cobs.

Another important bridging agent is cellophane flakes. As the cement slurry encounters the lost-circulation zone, the flakes form a mat at the fracture face. They can also plate out across high-permeability zones. The thickness of the flakes is usually 0.02 to 0.06 mm, and the planar dimensions are less than 1 cm on each side. The normal concentration of cellophane flakes is between 0.125 and 0.500 lbm/sk.

More recently, fibers made from glass or synthetic polymers have been added to cement slurries to prevent lost circulation (Messier et al., 2002). As the cement slurry enters the lost-circulation zone, the fibers associate to form a mat that promotes cement filtercake development. This technique has been used successfully for both primary and remedial cementing. The concentration of fibers in the slurry normally varies from 2 to 3 lbm/bbl.

3-9.2 Thixotropic cements

When vugular or cavernous zones are so large that bridging agents are ineffective, thixotropic cements are often indicated. When such slurries enter the formation, they are no longer subjected to shear; as a result, they gel and become self-supporting. Eventually, the thixotropic cement plugs the lost circulation. The chemical nature of such systems is thoroughly presented in Chapter 7.

3-10 Miscellaneous cement additives

There are a number of materials added to cement slurries that do not fit into any general category. These include antifoam agents, fibrous additives to improve cement durability, radioactive tracing agents, and mud decontaminants.

3-10.1 Antifoam agents

Many cement additives can cause the slurry to foam during mixing. Excessive slurry foaming can have several undesirable consequences. Slurry gelation can result, and loss of hydraulic pressure during pumping can occur owing to cavitation in the mixing system. In addition, air entrainment may cause higher-than-desired slurry densities. During slurry mixing, a densitometer is used to help field personnel proportion the ingredients (Chapter 11). If air is present in the slurry at the surface, the density of the system “cement + water + air” is measured. Because the air becomes compressed downhole,
the densitometer underestimates the true downhole slurry density. Antifoam agents are usually added to the mix water or dry-blended with the cement to prevent such problems.

Antifoam agents produce a shift in surface tension, alter the dispersibility of solids, or both, so that the conditions required to produce a foam are no longer present. In general, antifoams must have the following characteristics to be effective.

- Insoluble in the foaming system
- A lower surface tension than the foaming system (Lichtman and Gammon, 1979)

The antifoam agent functions largely by spreading on the surface of the foam or entering the foam. Because the film formed by the spread of antifoam on the surface of a foaming liquid does not support foam, the foam situation is alleviated.

In well cementing, two classes of antifoam agents are commonly used: polyglycol ethers and silicones. Very small concentrations can achieve adequate foam prevention, usually less than 0.1% BWOC.

Polyethylene glycol is most frequently used because of its lower cost and is effective in most situations; however, it must be present in the system before mixing. Field experience has shown that post-addition of polyethylene glycol is inefficient, and in some cases foam stabilization can result.

The silicones are highly effective antifoam agents. They are suspensions of finely divided particles of silica dispersed in polydimethylsiloxane or similar silicones. Oil-in-water emulsions at 10% to 30% activity also exist. Unlike the polyglycol ethers, the silicones will destroy a foam regardless of when they are added to the system.

3-10.2 Strengthening agents

Fibrous materials are available that, when added to well cements in concentrations between 0.15% and 0.5% BWOC, increase the cement’s resistance to the stresses associated with perforating, hydraulic fracturing, and formation movement (Carter et al., 1968; Shi et al., 1995). Such materials transmit localized stresses more evenly throughout the cement matrix. Nylon fibers, with fiber lengths up to 1 in., are commonly used.

More recently, metallic microribbons were introduced to improve the mechanical properties of set cement (Baret et al., 2002). The microribbon concentration is usually about 1.5% by volume of slurry. At this concentration, the set cement has significantly improved impact resistance, toughness, and tensile strength. This system is particularly effective for kickoff plugs (Chapter 14).

Another material that dramatically improves the impact resistance and flexural strength of well cements is particulated rubber (unpublished data, F.E. Hook, 1971). This material is usually added in concentrations up to 5% BWOC. Latex-modified cements also exhibit improved flexural strength (Chapter 7). More recently, the principle of adding flexible particles to cement has been developed further. As discussed in Chapter 8, the well cementing industry is paying more attention to set-cement mechanical properties other than compressive strength. During a well’s lifetime, the cement sheath can be exposed to stresses that may cause conventional set cements to fail. Adding flexible particles improves the set cement’s resistance to such stresses, providing better long-term zonal isolation (Le Roy-Delage et al., 2000; Bosma et al., 2000).

3-10.3 Radioactive tracing agents

Radioactive compounds are sometimes added to cement slurries to more easily determine their location behind casing. Radioactive tracers were once used to determine the fill-up or top of the cement column; however, temperature surveys and cement bond logs have largely assumed this function. Radioactive slurries still find occasional use in remedial cementing to locate the slurry after placement. A base radiation log is run before the cement job to measure the natural formation radioactivity. After the job is completed, another radiation log is generated, and the location of the remedial slurry is determined by comparison with the base log (Chapter 15).

The most common radioactive agents for well cementing are $^{131}$I (half-life: 8.1 days) and $^{192}$Ir (half-life: 74 days). The iodine is generally available as a liquid. Sand or glass beads tagged with iridium 192 are often available in areas where tracers are used with hydraulic fracturing fluids.

3-10.4 Mud decontaminants

Certain chemicals in drilling fluids, such as tannins, lignins, starches, celluloses, and various chemically treated lignosulfonates, can severely retard a Portland cement slurry. To minimize such effects in the event that the cement slurry and the mud become intermixed, chemicals such as paraformaldehyde or blends of paraformaldehyde and sodium chromate are effective (Beach and Goins, 1957).

3-11 Summary
Table 3-19. Summary of Additives and Mechanisms of Action

<table>
<thead>
<tr>
<th>Additive Category</th>
<th>Benefits</th>
<th>Chemical Composition</th>
<th>Mechanism of Action</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Accelerator</strong></td>
<td>Shorter thickening time</td>
<td>CaCl$_2$, NaCl, Na and Ca formates, nitrates, and nitrites</td>
<td>Increased permeability of C-S-H phase layer†</td>
</tr>
<tr>
<td></td>
<td>Greater early compressive strength</td>
<td>Na silicates</td>
<td>Formation of C-S-H phase nuclei by reaction with Ca$^{2+}$ ions</td>
</tr>
<tr>
<td><strong>Retarder</strong></td>
<td>Longer thickening time</td>
<td>Lignosulfonates, Hydroxyacrylic acids, Cellulose derivatives, Organophosphonates</td>
<td>Adsorption onto C-S-H phase layer, reducing permeability, Prevention of nucleation and growth of hydration products</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Certain inorganic compounds</td>
<td>Precipitation of impermeable solids on C-S-H phase layer</td>
</tr>
<tr>
<td><strong>Extender</strong></td>
<td>Lower slurry density</td>
<td>Bentonite</td>
<td>Absorption of water</td>
</tr>
<tr>
<td></td>
<td>Greater slurry yield</td>
<td>Sodium silicates, Pozzolans, Gilsonite, Powdered coal</td>
<td>Formation of C-S-H phase + absorption of water, Lower density than cement</td>
</tr>
<tr>
<td><strong>Weighting agent</strong></td>
<td>Higher slurry density</td>
<td>Barite (BaSO$_4$), Hematite (Fe$_3$O$_4$), Ilmenite (FeTiO$_3$), Manganese tetraoxide (Mn$_3$O$_4$)</td>
<td>Higher density than cement</td>
</tr>
<tr>
<td><strong>Dispersant</strong></td>
<td>Lower slurry viscosity</td>
<td>PNS, PMS, Lignosulfonates, Polystyrene sulfonate</td>
<td>Induced electrostatic repulsion of cement grains, Steric hindrance that prevents flocculation of cement solids</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Polycarboxylate, Hydroxyacetate polycarboxylic acids</td>
<td></td>
</tr>
<tr>
<td><strong>Fluid-loss additive</strong></td>
<td>Reduced slurry dehydration</td>
<td>Cellulosic polymers, Polymers</td>
<td>Increased aqueous-phase viscosity, Reduced permeability of cement filtercake</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Polyamines, Sulfonated aromatic polymers, PVP, PVA, AMPS copolymers and terpolymers</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Bentonite, Latexes, Crosslinked PVA</td>
<td>Particle bridging across cement filtercake</td>
</tr>
<tr>
<td><strong>Lost-circulation control agent</strong></td>
<td>Prevention of loss of slurry to formation</td>
<td>Gilsonite, Granular coal, Cellophane flake, Nut shells, Fibrous additives</td>
<td>Bridging effect across formation, Induced thixotropic slurry behavior‡</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Gypsum, Certain soluble sulfate salts, Bentonite, Crosslinked cellulosic polymers</td>
<td></td>
</tr>
<tr>
<td><strong>Antifoam agent</strong></td>
<td>Reduced air entrainment during slurry mixing</td>
<td>Polyglycol ethers, Silicones</td>
<td>Insoluble in foaming system, Lower surface tension than foaming system</td>
</tr>
<tr>
<td><strong>Strengthening agent</strong></td>
<td>Increased tensile strength, flexural strength, and toughness</td>
<td>Glass and polymer fibers, Metallic microribbons, Ground rubber</td>
<td>Transmission of localized stresses more evenly throughout cement matrix</td>
</tr>
<tr>
<td><strong>Radioactive tracers</strong></td>
<td>Easier determination of cement location behind casing</td>
<td>$^{131}$I, $^{123}$I, $^{159}$I</td>
<td>Emission of radioactivity</td>
</tr>
</tbody>
</table>

† Proposed theoretical mechanism
‡ More than one mechanism may apply for certain classes of retarders. See text for clarification.
§ Discussed in Chapter 7
4-1 Introduction

Rheology is the study of the deformation and flow of materials. This chapter considers materials that are essentially in a liquid state. In this particular case, rheology can be described as the science that attempts to determine the intrinsic fluid properties—mainly viscosity—necessary to determine the relationships between the flow rate (shear rate) element and the pressure gradient (shear stress) element that causes fluid movement. To properly design, execute, and evaluate a primary cement job, one must first understand the rheological properties of the cement slurries. Proper rheological characterization is essential to

- evaluate the slurry’s mixability and pumpability
- optimize mud removal and slurry placement
- determine the friction pressure when the slurry flows in pipes and annuli
- evaluate the slurry’s ability to transport large particles (e.g., some lost circulation materials and fibers)
- predict how the wellbore-temperature profile affects slurry placement
- predict the annular pressure after slurry placement.

Despite a large body of research performed during the past 50 years, a complete rheological characterization of a cement slurry has yet to be achieved. This is because the rheological behavior of cement slurries depends on many different factors:

- water-to-cement ratio
- specific surface area of the cement powder, and more specifically the size and shape of the grains
- chemical composition of the cement and the relative distribution of the components at the grain surfaces
- presence of additives
- mixing and testing procedures.

This chapter concentrates on the rheological characterization and flow behavior of cement slurries in a wellbore; however, a large portion also applies to spacers. An introduction to the basic rheological principles precedes a discussion of common equipment and procedures to characterize cement-slurry rheology. Next, the limitations of current practices are discussed, along with suggestions for possible improvements. Finally, the equations governing the flow of cement slurries in pipes and annuli (both concentric and eccentric) are presented. All of the principal equations are also gathered in Appendix A.

4-2 Basic rheological principles and calculations

This section presents basic information about fluid rheology and fluid flow. It illustrates how the basic rheological calculations are usually performed in most field laboratories. After reading this section, the reader will have a foundation for the more theoretical discussion presented later in this chapter.

4-2.1 Types of flow

Under steady-state and isothermal conditions, fluids flow in either laminar flow or turbulent flow. These flow conditions are separated by a transition zone. Pipe flow will be used as an example to illustrate these concepts.

Laminar flow

When a fluid is flowing in a pipe in laminar flow, the individual particles in the fluid move forward in straight lines parallel to the pipe’s axis (Fig. 4-1). In most cases the particles in contact with the pipe wall are stationary. The velocity of the other particles across the pipe varies according to their proximity to pipe walls, with the particles at the center of the channel moving at the greatest speed.

The shape of the velocity profile varies from fluid to fluid, depending on the rheological behavior. The velocity profile for water, for example, displays a parabolic shape in which the particles are stationary at the wall and flow at twice the average velocity at the center. In some other fluids, the central portion moves as a solid plug with similar particle velocities, while the velocity decreases sharply to 0 close to the pipe wall (Fig. 4-2). This is not a true flow regime—though it is sometimes called the plug flow regime—but simply a pattern that is specific to some fluids in laminar flow.
Turbulent flow

When fluids are in turbulent flow, particles swirl within the pipe in a rolling motion that is quite distinct from the sliding motion of laminar flow (Fig. 4-3). Fluid particles now have a velocity with components that are not parallel to the pipe wall. The velocity is also time dependent. In such a flow regime, fluids witness a constant transfer of momentum from one region to another. With turbulent flow, the speed of flow increases rapidly away from the pipe wall and becomes fairly constant throughout the main part of the fluid.

At low flow rates, fluids always flow in the laminar regime, and their behavior can be characterized by a property called viscosity that will be discussed below. As the flow rate increases, fluids enter a transition regime before turbulent flow is established, and the flow becomes less dependent on viscosity and more dependent on inertial forces.

4-2.2 Basic definitions

In the laminar flow regime, fluid movement may be compared to a large number of platelets moving parallel to one another at different velocities (Fig. 4-4).
In this simple flow geometry, the velocity of the fluid particles varies linearly from one plate to the other. From Fig. 4-4, the shear rate (or velocity gradient) is constant and described mathematically in Eq. 4-1.

\[
\text{Shear rate} = \frac{\text{the velocity difference between 2 platelets}}{\text{the distance between 2 platelets}},
\]

or

\[
\frac{dv}{dx} = \frac{v_1 - v_2}{L}, \quad (4-1)
\]

where \( x \) is an axis perpendicular to the plates.

The dimensions of Eq. 4-1 are

\[
\text{length} \times \text{time}^{-1} = \text{length}. \quad \text{(time)}^{-1}.
\]

Therefore, the unit of shear rate is sec\(^{-1}\). The symbol for shear rate is \( \dot{\gamma} \).

Shear stress, denoted by the symbol \( \tau \), is the force per unit of surface area that causes the shearing, or, from Fig. 4-4:

\[
\tau = \frac{F}{A}. \quad (4-2)
\]

The dimensions of Eq. 4-2 are

\[
\text{force} \times \text{length}^{-2} = \text{force} \times \text{length}^{-2}. \quad \text{time}^{-1}.
\]

In common oilfield units, the unit of shear stress is lbf/100 ft\(^2\). In the SI system, the unit is the pascal (Pa).

The viscosity of a fluid is the ratio of the shear stress, \( \tau \), to the shear rate, \( \dot{\gamma} \). The symbol for viscosity is \( \mu \).

\[
\mu = \frac{\tau}{\dot{\gamma}}. \quad (4-3)
\]

The dimensions of Eq. 4-3 are

\[
\text{force} \times \text{length}^{-2} \times \text{time}^{-1} = \text{force} \times \text{length}^{-2} \times \text{time}. \quad \text{time}^{-1}.
\]

In common oilfield units, the unit of viscosity is the centipoise (cp). In the SI system, the unit is the pascal-second (Pa-s).

Returning to the simple case of laminar flow in a pipe, the shear stress can be considered to be proportional to the friction pressure gradient (or friction losses). For now, the shear rate can be considered as being proportional to the flow rate; however, this is not correct in the strictest sense. Viscosity is the fluid property that governs the friction pressure gradient/flow rate relationship. This property usually depends on the temperature and pressure. For most fluids used in well construction, viscosity also depends on shear rate. This will be explained in the following section.

In industrial applications such as cementing operations, fluids are not always exposed to the simple-shear situation described in Fig. 4-4. The velocities of fluid particles may vary in more than one direction (e.g., axial flow in an eccentric annulus), or they may exhibit more than one component (e.g., axial flow in an annulus with the inner pipe rotating). The shear-rate and shear-stress fields are thus described by a tensor, but the viscosity remains a scalar that depends on some invariants of these tensors. Understanding the relationship between the shear-rate and shear-stress tensors involves multiple fluid properties; however, this is beyond the scope of the discussion. In this chapter, the discussion will be limited to fluid viscosity.

### 4-2.3 Rheological models

The relationship between shear stress and shear rate in steady laminar flow defines Newtonian and non-Newtonian fluids.

**Newtonian fluids**

Newtonian fluids comply with the Newtonian model, in which the shear stress, \( \tau \), is directly proportional to the shear rate, \( \dot{\gamma} \). The equation is

\[
\tau = \mu \dot{\gamma} \quad (4-4)
\]

This relationship is illustrated in Fig. 4-5. The slope of the line represents the viscosity, \( \mu \), of the fluid. This is a constant that does not depend on the flow conditions but simply on temperature and pressure. Common Newtonian fluids include water, gasoline, and light oil.

In Fig. 4-6 one can see that Newtonian fluids begin to flow immediately when a pressure gradient is applied. As long as the fluid is in laminar flow, the friction-pressure gradient/flow rate relationship is linear, as is the shear-stress/shear-rate relationship. However, as the flow rate increases and the flow starts to become turbulent, the relationship is no longer linear, and friction pressure increases faster than in laminar flow.
Non-Newtonian fluids

The term non-Newtonian covers any fluid whose behavior deviates from the classic Newtonian model (i.e., the shear-stress/shear-rate relationship differs from a straight line that goes through the origin). In addition to being temperature and pressure dependent, these fluids’ viscosities can either decrease with shear rate (in which case they are called shear thinning) or increase with shear rate (in which case they are called shear thickening). Most drilling muds, cement slurries, and heavy oils are shear thinning. There are three mathematical models commonly used in the well cementing industry to describe the behavior of such fluids.

- Power-law model
- Bingham model
- Herschel-Bulkley model

Power-law fluids

Power-law fluids are part of a class known as pseudo-plastic fluids. Like Newtonian fluids, power-law fluids flow immediately when a pressure gradient is applied. However, unlike Newtonian fluids, the relationship between shear rate and shear stress is not linear (Fig. 4-7).

\[
\tau = k\dot{\gamma}^n \quad (4-5a)
\]
\[
\mu = k\dot{\gamma}^{n-1} \quad (4-5b)
\]

When \( n \) is greater than 1, power-law fluids are shear thickening. When \( n \) is less than 1, they are shear thinning. Of course, when \( n \) is equal to 1, the power-law model reduces to the Newtonian model. The viscosity of shear thinning power-law fluids (the most common) varies from infinity at 0 shear rate to 0 at infinite shear rate. This lower limit is not physically sound; therefore, one should exercise caution when applying the power-law model to situations outside of the shear-rate range in which the rheological characterization of a fluid was performed.

As long as a power-law fluid is in laminar flow, the friction pressure gradient/flow rate relationship follows the power law (Fig. 4-8). However, as the flow rate increases and the flow starts to become turbulent, the relationship changes and friction pressures increase more quickly than predicted by the laminar model.
Bingham plastic fluids

As shown in Fig. 4-9, the distinguishing characteristic of a Bingham plastic fluid is that it will remain unsheared until the applied stress reaches a minimum value.

Two parameters define the Bingham plastic model:

- the value of $\tau$ for $\dot{\gamma} = 0$, $\tau_y$
- the slope of the straight line, $\mu_p$.

$\mu_p$ is constant and is called the plastic viscosity. $\tau_y$ is called the Bingham yield stress.

Bingham fluids behave in a manner described by the following equations:

$$\tau = \tau_y + \mu_p \dot{\gamma} \text{ when } \tau > \tau_y,$$

$$(4-6a)$$

$$\dot{\gamma} = 0 \text{ when } \tau \leq \tau_y,$$

$$(4-6b)$$

Therefore, Bingham plastic fluids are shear thinning fluids whose viscosities vary from infinity at 0 shear rate to their plastic viscosities at infinite shear rates.

Bingham plastic fluids require a minimum pressure gradient to initiate flow (Fig. 4-10). As long as the fluid is in laminar flow, the friction pressure gradient/flow rate relationship increases nonlinearly and then tends towards linear behavior. Thus, it differs from the shear-stress/shear-rate behavior because, strictly speaking, the flow rate cannot be considered to be proportional to the shear rate. As in other fluid models, as the flow rate increases and the flow starts to become turbulent, the relationship changes and friction pressures increase much faster than predicted by the laminar relationship.

Herschel-Bulkley fluids

Herschel-Bulkley fluids combine power-law and Bingham plastic behaviors. Like Bingham plastic fluids, there is a yield stress that must be exceeded before flow commences (Herschel and Bulkley, 1926). Above the yield stress, as with power-law fluids, the shear-rate/shear-stress relationship follows the power law.

Herschel-Bulkley fluids are described by Eqs. 4-6b, 4-7a, and 4-7b, and their behavior is illustrated in Fig. 4-11.

$$\tau = \tau_y + k\dot{\gamma}^n \text{ when } \tau > \tau_y,$$

$$(4-7a)$$
or

$$\mu = \frac{\tau_y + k\dot{\gamma}^n}{\dot{\gamma}}$$

$$(4-7b)$$
In the most common case, in which \( n \) is smaller than 1, Herschel-Bulkley fluids are shear thinning. Their viscosities vary from infinity at 0 shear rate to 0 at infinite shear rate. As with power-law fluids, this lower limit is not physically sound, and caution should be exercised when applying this three-parameter model to situations outside the shear-rate range in which the rheological characterization was performed.

As long as the fluid is in laminar flow, the friction pressure gradient/flow rate relationship begins with an offset at 0 flow rate and then increases nonlinearly (Fig. 4-12). As the flow rate increases and the flow begins to become turbulent, the relationship changes and friction pressures increase much faster than predicted by the laminar relationship.

### Other rheological models

Two other rheological models are often quoted in the literature concerning cement-slurry rheology: the Casson model (1959) and the Robertson and Stiff model (1976). They are described by Eqs. 4-8 and 4-9, respectively.

\[
\tau = \left( \sqrt{\frac{\tau_y}{\mu_p}} + \sqrt{\frac{\mu_p \cdot \dot{\gamma}}{n}} \right)^2 \quad (4-8)
\]

\[
\tau = \left[ \left( \frac{1}{\tau_y} \right)^{\frac{1}{n}} + \frac{1}{k_n \cdot \dot{\gamma}} \right]^n \quad (4-9)
\]

Like the Herschel-Bulkley model, these two models combine the use of a yield stress with shear-thinning behavior for \( n < 1 \).

#### 4.2.4 Shear-rate range encountered in a wellbore

Before presenting the equipment and procedures employed to characterize the rheological properties of cement slurries, it is important to discuss the shear-rate range to which these fluids are exposed during placement in the wellbore. This discussion is limited to flow in pipes and in narrow concentric annuli. Also, the following assumptions are made:

- The fluid is incompressible and inelastic.
- The flow is laminar, steady, and isothermal.
- The velocity at the wall(s) is nil.

For a fluid flowing in a pipe or in a concentric annulus, the shear rate varies from 0 at the pipe axis or somewhere in the annulus to a maximum value, \( \dot{\gamma}_{\text{W}} \), at one of the walls.

With Newtonian fluids, the shear rate at the walls depends only on the size of the flow path and the mean velocity of the fluid, \( \overline{v} \) (or, by another name, the flow rate, \( q \)), and can be expressed as (Whorlow, 1980)

\[
\dot{\gamma}_{\text{NW}} = \frac{8\overline{v}}{d_w} = \frac{32q}{\pi(d_w)^3}, \quad (4-10)
\]

for a pipe of internal diameter \( d_w \), and

\[
\dot{\gamma}_{\text{NW}} = \frac{12\overline{v}}{d_o - d_w} = \frac{48q}{\pi(d_o + d_w)(d_o - d_w)^2} \quad (4-11)
\]

for a narrow concentric annulus of inner diameter \( d_w \) and of outer diameter \( d_o \). For non-Newtonian fluids, Rabinowitsch (1929) and Mooney (1931) derived the following equations.
Pipe flow is expressed as

\[
\dot{\gamma}_w = \frac{3n' + 1}{4n'} \times \frac{8\bar{V}}{d_w} = \frac{3n' + 1}{4n'} \dot{\gamma}_{NW},
\]

with

\[
n' = \frac{\log(\tau_w)}{\log(8\bar{V}/d_w)}.
\]

\(\tau_w\) is the shear stress at the wall for pipe flow, and

\[
\tau_w = \frac{d_w}{4} \left(\frac{dp}{dz}\right)_f.
\]

Narrow concentric annular flow is expressed as

\[
\dot{\gamma}_w = \frac{2n' + 1}{3n'} \times \frac{12\bar{V}}{d_o - d_w} = \frac{2n' + 1}{3n'} \dot{\gamma}_{NW},
\]

with

\[
n' = \frac{\log(\tau_w)}{\log\left(\frac{12\bar{V}}{d_o - d_w}\right)}.
\]

The shear stress at the wall is

\[
\tau_w = \frac{d_s - d_w}{4} \left(\frac{dp}{dz}\right)_f,
\]

for narrow concentric annular flow. In Eq. 4-14 and 4-17, \(\left(\frac{dp}{dz}\right)_f\) is the friction pressure per unit length along the axis of the flow.

Thus, the shear rate at the wall, \(\dot{\gamma}_w\), for non-Newtonian fluids cannot be defined in a simple way unless the precise rheology of the fluid is known. For pipes or narrow concentric annuli, Eqs. 4-10 and 4-11 represent only a lower limit for the shear rate at the wall for non-Newtonian fluids, provided they are shear thinning (i.e., \(n < 1\), which is the case for most cement slurries and spacers). But it is always worthwhile to calculate the value that a Newtonian fluid would experience in a given application because it gives a rough idea of the order of magnitude of the shear rate. Table 4-1 shows typical figures for \(\dot{\gamma}_{NW}\), varying from a few reciprocal seconds up to more than 1,000 sec\(^{-1}\).

As can be expected from Eqs. 4-10 and 4-11, the Newtonian shear rate at the wall is extremely sensitive to the pipe diameter or annular size. Generally speaking, the variations in the true shear rate at the wall owing to variations in hole geometry may be greater than those caused by variations in \(n'\) (i.e., in the non-Newtonian behavior of the fluids).

As stated earlier, the shear rate is not uniform across the gap in either of these geometries. Therefore, theoretically speaking, solving flow equations for time-independent\(^1\) non-Newtonian fluids in pipes or concentric annuli requires a knowledge of the shear-stress/shear-rate relationship in the range from the shear rate at the wall down to 0 shear rate. In fact, for a given friction pressure gradient and therefore a given shear stress at the

---

Table 4-1a. Newtonian Shear Rates for Various Pipe Diameters and Flow Rates

<table>
<thead>
<tr>
<th>Pipe flow rate (bbl/min)</th>
<th>1</th>
<th>2</th>
<th>5</th>
<th>10</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pipe flow rate (L/min)</td>
<td>159</td>
<td>318</td>
<td>795</td>
<td>1,590</td>
</tr>
<tr>
<td>Pipe flow rate (m(^3)/s)</td>
<td>2.65 (\times) 10(^{-3})</td>
<td>5.30 (\times) 10(^{-3})</td>
<td>1.32 (\times) 10(^{-2})</td>
<td>2.65 (\times) 10(^{-2})</td>
</tr>
<tr>
<td>Shear rate in 2-in. [50.8-mm] pipe (sec(^{-1}))</td>
<td>206</td>
<td>412</td>
<td>1,030</td>
<td>2,060</td>
</tr>
<tr>
<td>Shear rate in 5-in. [127-mm] pipe (sec(^{-1}))</td>
<td>13.2</td>
<td>26.4</td>
<td>65.9</td>
<td>132</td>
</tr>
<tr>
<td>Shear rate in 10-in. [254-mm] pipe (sec(^{-1}))</td>
<td>1.65</td>
<td>3.29</td>
<td>8.24</td>
<td>16.5</td>
</tr>
</tbody>
</table>

\(^1\)For time-dependent fluids, the issue can be very different (see Section 4–4.3).
wall, the flow rate depends mainly on the local shear-stress/shear-rate relationship in a region, from shear stress at the wall, $\gamma_w$, down to typically one-tenth of that value. For eccentric annuli, the shear range that must be covered is much wider because of the uneven distribution of both the gap and the velocity around the annulus (Section 4-6.3).

### 4-2.5 Laboratory determination of rheological properties

The standard equipment used to characterize the rheological properties of cement slurries and other oilfield fluids (drilling muds, spacers, fracturing fluids, etc.) is a coaxial cylinder viscometer, described by Savins and Roper in 1954 (Fig. 4-13) (Appendix B). The test fluid, contained in a large cup, is sheared between an outer sleeve (the rotor) and an inner cylinder (the bob) (Fig. 4-14). The rotor spins at various preselected rotational speeds. The bob is attached to a torsion spring that deflects as torque is exerted by the fluid. The torsion-spring deflection is indicated on a dial that reads from 0 to 300. The dial readings and rotational speeds are converted to shear stress in lbf/100 ft² (or Pa) and shear rate in sec⁻¹.

The characteristics of the rotor-and-bob geometry are

- $r_2 = 0.725$ in. [1.8415 cm]
- $r_1 = 0.679$ in. [1.7247 cm]
- $L = 1.5$ in. [3.8 cm].

Depending upon the model, the outer sleeve can rotate at two (600 and 300 rpm), six (600, 300, 200, 100, 6, and 3 rpm), or more (previous values plus 60, 30, 20, 10, 6, 3, 2, and 1 rpm) rotational speeds. This covers a Newtonian shear-rate range from at least 5 sec⁻¹ to 1,022 sec⁻¹ (at the inner cylinder surface). The 6-speed models are the most common, but 12-speed models are preferred for reasons that will be explained later.

<table>
<thead>
<tr>
<th>Annular flow rate (bbl/min)</th>
<th>1</th>
<th>2</th>
<th>5</th>
<th>10</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annular flow rate (L/min)</td>
<td>159</td>
<td>318</td>
<td>795</td>
<td>1,590</td>
</tr>
<tr>
<td>Annular flow rate (m³/s)</td>
<td>$2.65 \times 10^{-3}$</td>
<td>$5.30 \times 10^{-3}$</td>
<td>$1.32 \times 10^{-2}$</td>
<td>$2.65 \times 10^{-2}$</td>
</tr>
<tr>
<td>Shear rate in 4- to 5½-in.</td>
<td>116</td>
<td>231</td>
<td>578</td>
<td>1,160</td>
</tr>
<tr>
<td>[101.6- to 139.7-mm] annulus (sec⁻¹)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Shear rate in 7- to 8½-in.</td>
<td>70.8</td>
<td>142</td>
<td>354</td>
<td>708</td>
</tr>
<tr>
<td>[177.8- to 215.9-mm] annulus (sec⁻¹)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Shear rate in 9½- to 12¼-in.</td>
<td>16.4</td>
<td>32.8</td>
<td>81.9</td>
<td>164</td>
</tr>
<tr>
<td>[244.5- to 311.2-mm] annulus (sec⁻¹)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Shear rate in 13½- to 17½-in.</td>
<td>4.60</td>
<td>9.19</td>
<td>23.0</td>
<td>46.0</td>
</tr>
<tr>
<td>[339.8- to 444.5-mm] annulus (sec⁻¹)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
The standard torsion spring has a nominal range from 0 to 116,000 dynes-cm [0.0116 N-m], which corresponds to a shear-stress range from 0 to 320 lbf/100 ft² [0 to 153 Pa] (calculated at the inner cylinder surface, and assuming a length correction factor of 1.064% to account for end effects). Most manufacturers provide other springs with stiffnesses of one-fifth, one-half, two, or five times that of the standard spring.

This equipment satisfies the principal requirements described in Recommended Practice for Testing Well Cements (American Petroleum Institute [API] Recommended Practice [RP] 10B (1999), and International Organization for Standardization [ISO] 10426-2, (2003). The radial ratio of the cylinders is larger than 0.9 to ensure homogeneous shear. The instrument provides at least 5 readings within a shear-rate range from near 0 to at least 511 sec⁻¹. The size of the annular gap (1.17 mm) is such that slurries with particles as large as 120 μm can be considered homogeneous.

**Pressurized equipment**

Several coaxial cylinder viscometers can measure fluid rheology at elevated temperatures and pressures (Appendix B). Pressure is applied to prevent water evaporation or boiling at temperatures above 185°F [85°C]. One may also investigate the effect of pressure on a fluid’s rheological properties. The couette geometry conforms to the requirements described in API RP 10B and ISO 10426-2.

**4-2.5.1 Experimental procedure**

The key steps of the test procedure and common deviations from it are summarized below. More details are given in Appendix B. The complete procedure is described in API RP 10B (ISO 10426-2).

The basic procedure is to place the test fluid in the viscometer and measure the instrument-dial readings at the various rotational speeds. The dial readings are converted to shear stress and the rotational speeds are converted to shear rate. Then, a shear-stress/shear-rate plot is generated. Depending on the nature of the resulting curve, one can determine the most appropriate rheological model (Newtonian, Bingham plastic, or power-law). Then, the fluid parameters (e.g., plastic viscosity, yield value, flow-behavior index, and consistency index) can be calculated.

The slurry is first mixed according to a procedure defined in API RP 10B and ISO 10426-2 (Appendix B). Ideally, the slurry is then brought to temperature and pressure in a consistometer according to the appropriate thickening-time-test schedule. Once the preconditioning temperature and pressure are reached, the slurry is stirred for an additional 20 min. If the test temperature exceeds 185°F [85°C], the preconditioning period takes place in a pressurized consistometer. After the preconditioning period, the slurry is cooled as quickly as possible to 185°F [85°C] and the pressure is released. Once the preconditioning period is over, the slurry is vigorously stirred to redisperse solids that may have settled and is then transferred to the preheated viscometer.

The test consists of shearing the fluid at the lowest rotational speed for 10 sec before recording the corresponding torque reading. All the remaining readings are then taken in ascending order, and then in descending order, after 10 sec of rotation at each speed. The objective of this sequence, known as a *hysteresis loop*, is to detect true time-dependent effects such as thixotropy or other artifacts that will be discussed later.

During the test, the slurry should not be exposed to shear rates higher than 511 sec⁻¹ (i.e., 300 rpm with the standard spring). This restriction greatly improves the reproducibility of results among laboratories (Beirute, 1986). This point is illustrated in Figs. 4-15 and 4-16. It is important to point out that these data were generated using an obsolete version of the API procedure.

**4-2.5.2 Gel strength**

The yield value (expressed in lbf/100 ft² or Pa) is a measurement of the attractive forces that exist between the particles in a fluid while under flowing conditions. The *gel strength* is a measure of the attractive forces between the particles in a fluid under static conditions.

The gel strength may be measured after the hysteresis loop or as an independent measurement. The viscometer is turned off for 10 sec, after which the rotational speed is set to be equivalent to 5.1 sec⁻¹ (3 rpm). However, the preconditioning period may be omitted if the objective is to measure the rheology of a cement slurry at ambient temperature just after mixing.
The maximum reading is the 10-sec gel strength. The dial reading after 1 min of rotation at 5.1 sec⁻¹ is sometimes also recorded and compared to the 10-sec gel to quantify the gel’s shear sensitivity. To determine the 10-min gel strength, the above operation is repeated 10 min after turning off the viscometer.

4-2.5.3 Data analysis
At any given rotational speed, Ω, the ramp-up/ramp-down dial readings, θ, are averaged³ and then converted to shear rates and shear stresses at the inner cylinder (bob) using the following equations:

\[ \dot{\gamma} = 16.28 \times \Omega, \]  
\[ \dot{\gamma} = 1.705 \times \Omega, \]  
\[ \tau = 0.5109 \times \theta, \]  
\[ \tau = 1.067 \times \theta, \]

where \( \Omega \) is in rad/s, or \( \Omega \) is in rpm.

The peak readings are converted to 10-sec and 10-min gel strength values using Eq. 4-19 or 4-20.

Strictly speaking, the shear-rate formula is only truly valid for Newtonian fluids; nevertheless, it leads to reasonably accurate values for other fluids (Section 4-3.4). These shear-rate/shear-stress values are fitted to various rheological models. The model that best fits the data is selected.

Example
The data analysis will be illustrated using the specific example of a slurry containing a polymeric fluid-loss additive that has a strong effect on slurry rheology. Using the standard API/ISO procedure (Appendix B), the following data were recorded.

<table>
<thead>
<tr>
<th>Rotational Speed (rpm)</th>
<th>Ramp-Up Readings</th>
<th>Ramp-Down Readings</th>
<th>Average Readings</th>
</tr>
</thead>
<tbody>
<tr>
<td>300</td>
<td>97</td>
<td>97</td>
<td>97</td>
</tr>
<tr>
<td>200</td>
<td>69</td>
<td>70</td>
<td>69.5</td>
</tr>
<tr>
<td>100</td>
<td>39</td>
<td>39</td>
<td>39</td>
</tr>
<tr>
<td>60</td>
<td>27</td>
<td>26</td>
<td>26.5</td>
</tr>
<tr>
<td>30</td>
<td>18</td>
<td>16</td>
<td>17</td>
</tr>
<tr>
<td>6</td>
<td>9</td>
<td>7</td>
<td>8</td>
</tr>
<tr>
<td>3</td>
<td>8</td>
<td>5</td>
<td>6.5</td>
</tr>
</tbody>
</table>

³Of course, this averaging is not meaningful if there are large differences between the ramp-up and ramp-down readings.
Even though the fit is not perfect, the Bingham plastic model better describes the rheological behavior of the cement slurry. This example highlights the typical weaknesses of these models in describing the rheology of cement slurries. The Bingham plastic model tends to overestimate shear stresses at low shear rates, while the power-law model can lead to significant errors across the entire shear-rate range. The power-law model usually underestimates shear stresses at both ends of the shear-rate spectrum and overestimates them at intermediate values.

**Comments**

Because API/ISO standards discourage using the 600-rpm speed, the 2-speed equipment should no longer be used. The six-speed models also suffer from a severe limitation. Because the 6- and 3-rpm readings are not very accurate, or may be affected by wall slip (Section 4-3.7), the user may be left with only 3 useful readings—100, 200, and 300 rpm. These rotational speeds correspond to a fairly narrow shear-rate range (170 sec\(^{-1}\) to 511 sec\(^{-1}\)). Therefore, when the maximum shear rate experienced by a cement slurry during placement in the wellbore is likely to be lower than 170 sec\(^{-1}\), using equipment allowing measurements between 6 and 100 rpm [10 sec\(^{-1}\) and 170 sec\(^{-1}\)] is strongly recommended. Section 4-2.4 describes how one determines the anticipated wellbore shear rates.

When standard oilfield equipment is well maintained, the accuracy of a built-in torque-measuring device is reasonable. Once calibrated, a typical expected shear-stress error at low dial readings (≈10) is ±15%. The error can be much higher if the bearing spring is damaged. It is not unusual to encounter equipment for which the relative error is on the order of ±50% at such low shear stresses (Fig. 4-18).

**Table 4-3. Rheological Model Parameters**

<table>
<thead>
<tr>
<th>Model</th>
<th>Correlation Coefficient</th>
<th>(n) or (\tau_y)</th>
<th>(k) or (\mu_p)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bingham plastic</td>
<td>0.9992</td>
<td>3.70 Pa</td>
<td>91.3 mPa-s</td>
</tr>
<tr>
<td>Power law</td>
<td>0.9878</td>
<td>0.5859</td>
<td>1.063 Pa-s (n)</td>
</tr>
</tbody>
</table>

† Determined using API-recommended equations for the data presented in Table 4-2.

**Table 4-4. Relative Shear-Stress Errors Between the Bingham Plastic and Power-Law Models and the Measured Data**

<table>
<thead>
<tr>
<th>Rotational Speed (rpm)</th>
<th>Bingham Plastic (%)</th>
<th>Power Law (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>300</td>
<td>–1.6</td>
<td>17.2</td>
</tr>
<tr>
<td>200</td>
<td>2.0</td>
<td>8.8</td>
</tr>
<tr>
<td>100</td>
<td>3.4</td>
<td>–8.2</td>
</tr>
<tr>
<td>60</td>
<td>3.7</td>
<td>–18.1</td>
</tr>
<tr>
<td>30</td>
<td>3.7</td>
<td>–22.6</td>
</tr>
<tr>
<td>6</td>
<td>–13.4</td>
<td>–1.5</td>
</tr>
<tr>
<td>3</td>
<td>–25.5</td>
<td>16.8</td>
</tr>
</tbody>
</table>

† Relative error is defined as: \(\frac{\text{measured} - \text{measured}}{\text{measured}}\).

**Fig. 4-17.** Rheological plot corresponding to measured data shown in Table 4-2. Fitting to Bingham plastic and power-law models is also shown. The shear stresses and shear rates were determined from Eqs. 4-18 and 4-19. Model parameters are given in Table 4-3.

**Fig. 4-18.** Relative error of shear-stress measurements using standard oilfield equipment. Tests were performed with a Newtonian oil using the standard API/ISO procedure.

††The power-law model parameters are determined from a linear regression performed on the logarithm of the shear stresses and the shear rates as recommended in API RP 10B (1999) and ISO 10426-2 (2003). Better prediction of shear stresses in the intermediate and high-shear-rate range could be obtained by performing a nonlinear regression directly on the shear stresses and shear rates.
This creates problems when trying to characterize the rheology of low-viscosity fluids such as dispersed cement slurries.

By the same token, it is equally important to make sure that the bob and rotor are concentric and that they end up on the same plane at the bottom of the coaxial geometry, because this design minimizes end effects.

**4-3 Limitations of field practices**

4-3.1 Principle and flow equations

As discussed earlier, in a coaxial cylinder viscometer the test material is confined between two concentric cylinders of radii \( r_2 \) and \( r_1 \) \((r_2 > r_1)\), one of them being rotated at a velocity \( \Omega \). Assume for the time being that the fluid elements are moving in concentric circles around the common axis (Fig. 4-14).

In steady state, a momentum balance shows that the shear stress \( \tau \) at any radius \( r \) is given by Whorlow (1980).

\[
\tau = \frac{\chi}{2\pi r^2},
\]

where \( \chi \) is the torque acting per unit length on a cylindrical surface of radius \( r \). In practice, \( \chi \) is measured from the torque acting on one of the cylinders of length \( L \). This expression shows that the shear stress decreases from a maximum value of

\[
\tau_1 = \frac{\chi}{2\pi (r_1)^2}
\]

at the inner cylinder surface to

\[
\tau_2 = \frac{\chi}{2\pi (r_2)^2}
\]

at the outer cylinder surface. Shear stress (and therefore shear rate) will be uniform only if the radius ratio,

\[
R_r = \frac{r_2}{r_1},
\]

is close to unity. The radius ratio is especially important for shear thinning fluids. As the radius ratio increases, so does the range of shear rates the fluid will experience in the viscometer.

The governing flow equation in a coaxial cylinder viscometer is (Whorlow, 1980)

\[
\Omega = \frac{1}{2} \int_{\tau_1}^{\tau_2} \frac{\dot{\gamma}}{\tau} \, dt. \tag{4-22}
\]

Because both limits of the integral are functions of the torque, there is no general analytical expression for the shear rate and the viscosity of a non-Newtonian fluid in such a geometry. Therefore, the shear-rate profile cannot be determined a priori, because it depends on the non-Newtonian behavior of the fluid, as well as on the rotational speed and the viscometer dimensions. To use such equipment to measure the flow curve of a non-Newtonian fluid, it is necessary to either assume a specific rheological model to use in conjunction with Eq. 4-22 or to make \( r_2/r_1 \) sufficiently close to unity that the variations of shear stress across the gap are negligible.

For fluids exhibiting a yield stress, Eq. 4-22 is valid only when \( \tau_2 \geq \tau_y \). When \( \tau_2 \leq \tau_y \leq \tau_1 \) the shear stress from \( r_2 \) to \( r_y \) is smaller than the yield stress of the fluid; therefore, the effective annular gap is reduced. Because the shear rate is 0 from \( r_2 \) to \( r_y \), this parameter is defined by

\[
r_y = \sqrt{\frac{\chi}{2\pi \tau_y}}, \tag{4-23}
\]

and Eq. 4-22 then becomes

\[
\Omega = \frac{1}{2} \int_{r_2}^{r_y} \frac{\dot{\gamma}}{\tau} \, dt. \tag{4-24}
\]

When the condition to apply Eq. 4-24 is satisfied, i.e., the fluid is not sheared from \( r_2 \) to \( r_y \), fluid particles in this part of the annular gap are moving at the same rotational velocity as the outer cylinder as shown in Fig. 4-19. Consequently, this situation is sometimes referred to as plug flow. Of course, when \( \tau_1 \leq \tau_y \) there is no flow at all.

**Fig. 4-19.** Velocity profile of a Bingham plastic fluid in a standard oil-field viscometer. \( r_1 = 1.7247 \) and \( r_2 = 1.8415 \) cm, corresponding to the inner and outer radii of the cylinders. In this particular case, the fluid is not sheared between \( r = 1.8181 \) and \( r_2 \) because the local shear stress is smaller than the fluid yield stress.
4.3.2 Flow of model fluids in coaxial cylinder viscometers

When a rheological model is assumed for the fluid to be characterized, a simple analytical expression can sometimes be determined for the torque as a function of the rotational speed.

For a Newtonian fluid, the flow equation is

\[ \frac{\chi}{2\pi(r_1)^2} = \mu \times \frac{2 \times (R_r)^2 \times \Omega}{(R_r)^2 - 1}, \]  
(4-25)

and the shear rates at the inner and outer surfaces are, respectively,

\[ \dot{\gamma}_1 = \frac{2 \times (R_r)^2 \times \Omega}{(R_r)^2 - 1}, \]  
(4-26)

and

\[ \dot{\gamma}_2 = \frac{2 \Omega}{(R_r)^2 - 1}, \]  
(4-27)

where \( R_r = r_2/r_1 \).

For a power-law fluid, the corresponding equations are

\[ \frac{\chi}{2\pi(r_1)^2} = k \times \left\{ \frac{2 \times (R_r)^2}{n \left[ \left( \frac{R_r}{r_1} \right)^n - 1 \right]} \right\}^n, \]  
(4-28)

\[ \dot{\gamma}_1 = \frac{2 \times (R_r)^2}{n \left[ \left( \frac{R_r}{r_1} \right)^n - 1 \right]} \times \Omega, \]  
(4-29)

and

\[ \dot{\gamma}_2 = \frac{2 \Omega}{n \left[ \left( \frac{R_r}{r_1} \right)^n - 1 \right]}, \]  
(4-30)

For a Bingham plastic fluid, different equations apply depending on the torque value. If \( \chi \geq 2\pi(r_2)^2\tau_y \), then all of the fluid in the gap is sheared in laminar flow, and the governing equations are

\[ \frac{\chi}{2\pi(r_1)^2} = \frac{2(R_r)^2}{(R_r)^2 - 1} \times \left[ \mu_p \Omega + \tau_y \ln (R_r) \right], \]  
(4-31)

\[ \dot{\gamma}_1 = \frac{2 \times (R_r)^2 \times \Omega}{(R_r)^2 - 1} + \left[ \frac{2 \times (R_r)^2 \times \ln (R_r)}{(R_r)^2 - 1} - 1 \right] \times \frac{\tau_y}{\mu_p}, \]  
(4-32)

and

\[ \dot{\gamma}_2 = \frac{2 \Omega}{(R_r)^2 - 1} + \left[ \frac{2 \ln (R_r)}{(R_r)^2 - 1} - 1 \right] \times \frac{\tau_y}{\mu_p}, \]  
(4-33)

If \( 2\pi(r_1)^2\tau_y \leq \chi \leq 2\pi(r_2)^2\tau_y \), part of the fluid is not sheared, the expressions for \( \dot{\gamma}_1 \) and \( \dot{\gamma}_2 \) are implicit, and:

\[ \Omega = \frac{\chi}{4\pi(r_1)^2 \mu_p} - \frac{\tau_y}{2\mu_p} \left[ 1 + \ln \left( \frac{\chi}{2\pi(r_1)^2 \tau_y} \right) \right]. \]  
(4-34)

If \( \chi \leq 2\pi(r_1)^2\tau_y \), then none of the fluid can flow and

\[ \Omega = 0. \]  
(4-35)

Thus, for Newtonian and power-law fluids flowing in a coaxial-cylinder geometry, the relationship between the torque and the rotational speed is similar to the relationship between shear stress and shear rate. It is linear for Newtonian fluids and follows a power law for power-law fluids.

For Bingham plastic fluids, as for all fluids exhibiting a yield stress, the equations are more complex. In the absence of a plug-flow region, there is a linear relationship between the torque and the rotational speed, with an apparent intercept equal to

\[ \chi = \frac{\tau_y}{(r_2^2 - r_1^2) \ln \frac{r_2}{r_1}}. \]  
(4-36)

Below a given torque value, \( \chi = 2\pi(r_2)^2\tau_y \), the relationship is independent of the outer radius, \( r_2 \), and nonlinear with an intercept of \( \chi = 2\pi(r_1)^2\tau_y \) for \( \Omega = 0 \) (Fig. 4-20).

Therefore, deriving the rheological parameters for the Newtonian and the power-law models from a series of torque/rotational speed measurements is straightforward. However, this simple approach cannot be applied to Bingham plastic fluids (and to fluids exhibiting a yield stress in general). Indeed, the flow behavior is described by Eqs. 4-31 and 4-34, whose limits of validity depend on the yield stress. This problem is usually overlooked, and all data are fitted according to the linear equation (Eq. 4-31).
Similar equations for the Casson model and the Robertson and Stiff model can be found in Whittaker et al. (1985). For Herschel-Bulkley fluids the governing flow equation is

\[ \dot{\gamma} = \frac{1}{K} \left( \frac{\tau}{\mu} - \theta \right) \frac{1}{\tau} \text{d}t, \]

(4-37)

where, as explained above, \( X \) is either equal to \( \tau_2 \) or \( \tau_y \). There is no simple analytical solution to this expression, and determining the rheological parameters from a series of rotational speeds and torque readings is more complicated than using rheological models involving only two parameters such as the power-law model or Bingham plastic model.

### 4.3.3 Application to standard oilfield equipment

When using the standard oilfield equipment, the shear stress at the inner cylinder can be written as

\[ \frac{\tau}{\mu_p} = f_{\tau} \times f_{\text{spring}} \times \dot{\gamma}, \]

(4-38)

where \( \Omega \) is the angular velocity in rad/sec, \( \Omega = \frac{1}{\tau} \int \left( \tau - \tau_y \right)^{1/n} \text{d}t, \)

(4-37)

where \( \mu = \frac{f_{\tau} \times f_{\text{spring}}}{f_{\dot{\gamma}}} \times m. \)

(4-42)

Using the standard spring, \( \mu = 0.3 \times m \) when rotational speeds are expressed in rad/sec and viscosities in Pa-s.

For power-law fluids, Eq. 4-28 can be reformulated as

\[ f_{\tau} \times f_{\text{spring}} \times \dot{\gamma} = k \left[ \frac{1 - (R_r)^2}{n} \right] \left[ \frac{1 - (R_r)^2}{n} \right] \times (f_{\dot{\gamma}} \times \Omega)^n. \]

(4-43)

Therefore, the power-law and consistency-fluid indices can be determined from a linear regression on the logarithm of the readings and the logarithm of the rotational velocities. If \( m \) is the slope of this regression.
and $b$ its intercept, the power-law parameters of the fluid are given by

$$n = m$$

(4-44)

and

$$k = \left[ n \left( 1 - \left( \frac{R_r}{R_f} \right)^2 \right)^{-2} \right] \times f_s \times f_{spring} \times 10^b.$$  

(4-45)

Using the standard spring and expressing the rotational speeds in rpm,

$$k = \frac{15n(1 - 1.068 \pi)}{\pi} \times f_s \times f_{spring} \times 10^b,$$

(4-46)

where $k$ is in Pa-s$^n$, and

$$k = \frac{15n(1 - 1.068 \pi)}{\pi} \times f_s \times f_{spring} \times 10^b,$$

(4-47)

where $k$ is in lbf-s$^n$/100 ft$^2$.

For Bingham plastic fluids, and assuming the fluid is fully sheared in the annular gap, Eq. 4-31 can be rewritten as

$$f_s \times f_{spring} \times \theta = \mu_p \times \frac{2\times(R_r)^2 \ln(R_r)}{(R_f)^2 - 1} \times \frac{\Omega + \tau_y}{(R_f)^2 - 1}.$$  

(4-48)

Therefore, the plastic viscosity and the yield stress of the fluid can be determined from a linear regression. If $m$ is the slope of this regression and $b$ its intercept, the Bingham plastic parameters of the fluid are given by

$$\mu_p = f_s \times f_{spring} \times \frac{m}{f_\gamma}$$

(4-49)

and

$$\tau_y = f_s \times f_{spring} \times \frac{(R_r)^2 - 1}{2(R_f)^2 \ln(R_r)} \times b.$$  

(4-50)

When using the standard spring,

$$\mu_p = 0.3 \times m$$

(4-51)

When the rotational speeds are expressed in rpm and the plastic viscosities are expressed in Pa-s, 

$$\tau_y = 0.5109 \times 0.9372 \times b = 0.4789 \times b$$

when $\tau_y$ is in Pa and

$$\tau_y = b$$

(4-52)

when $\tau_y$ is in lbf/100 ft$^2$.

For the power-law and Bingham plastic models, the two rheological parameters can in principle be derived from readings taken at only two rotational speeds (Whittaker et al., 1985). But this so-called two-point method should always be applied with caution, particularly outside the shear-rate range limited by the two rotational speeds used.

Applying Eqs. 4-43 and 4-48 to the example given in Table 4-2 leads to the following values of the rheological parameters.

One can see that the yield stress and the consistency index are different from those presented in Table 4-3. An explanation for the discrepancy will be given in the next section.

### Table 4-5. Rheological Model Parameters†

<table>
<thead>
<tr>
<th>Model</th>
<th>$n$ or $\tau_f$</th>
<th>$k$ or $\mu_p$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bingham plastic</td>
<td>3.47 Pa</td>
<td>91.3 mPa-s</td>
</tr>
<tr>
<td>Power law</td>
<td>0.5859</td>
<td>1.038 Pa-s$^n$</td>
</tr>
</tbody>
</table>

† Determined according to Eqs. 4-43 and 4-48 from the data presented in Table 4-2.

#### 4-3.4 Newtonian and narrow-gap approximations

Earlier it was stressed that the formulas giving the shear rate at the inner cylinder surface (Eqs. 4-18 and 4-26) are valid only for a Newtonian fluid. Therefore, the recommended API/ISO procedure, which consists of converting rotational speeds to Newtonian shear rates at the inner cylindrical surface, is not completely correct. It leads to an overestimation of the consistency index for
power-law fluids and of the yield stress for Bingham plastic fluids. The expressions for the rheological parameter ratios are given by Eqs. 4-53 and 4-54, respectively.

\[
\frac{k_{NW}}{k} = \left[ \frac{1 - (R_r)^{-4}}{n \left( 1 - (R_r)^{-4} \right)^{2/n}} \right]^n \quad (4-53)
\]

\[
\frac{(\tau_y)_{NW}}{\tau_y} = \frac{2 \ln(R_r)}{1 - (R_r)^{-2}} \quad (4-54)
\]

Using Eqs. 4-53 and 4-54, the corresponding errors for the standard geometry used in the oil industry \((R_r = 1.068)\) range from 0.0% to 5.4% for the consistency index of power-law fluids when the power-law index varies from 0 to 1. For Bingham plastic fluids, the error is 0 for the plastic viscosity and 6.7% for the yield stress.

One may consider these errors to be negligible for practical purposes when using the standard oilfield geometry. However, when a larger annular gap is used—for example when testing cement slurries containing a significant volume of particles with a diameter larger than 120 \(\mu m\)—these errors can become significant. In such cases, one can use the true flow equations (Eqs. 4-28, 4-31, and 4-34) or the narrow-gap approximation described below (Mannheimer, 1982).

When the radial ratio of the cylinders is close to 1, the shear stress and the shear rate can be considered to be uniform in the annular gap and given by

\[
\tau_{ng} = \frac{2 \chi}{\pi (r_2 + r_1)^2} \quad (4-55)
\]

and

\[
\dot{\gamma}_{ng} = \frac{(r_2 + r_1) \Omega}{2 (r_2 - r_1)} \quad (4-56)
\]

Therefore, the values for the shear stress and the shear rate can be derived directly from the torques and the rotational speeds. The errors resulting from using this approximation can easily be determined.

For power-law fluids,

\[
\frac{k_{ng}}{k} = \frac{4}{(R_r + 1)^2} \left[ \frac{4 \times R_r - 1}{n \left( 1 - (R_r)^{-4} \right)^{2/n}} \right] \quad (4-57)
\]

For Bingham plastic fluids,

\[
\frac{(\mu_p)_{ng}}{\mu_p} = \frac{16 (R_r)^2}{(R_r + 1)^{4/3}} \quad (4-58)
\]

and

\[
\frac{(\tau_y)_{ng}}{\tau_y} = \frac{8 \times (R_r)^2 \ln(R_r)}{(R_r - 1)(R_r + 1)^3} \quad (4-59)
\]

With the standard oilfield geometry, this error leads to an overestimation (Eqs. 4-58 and 4-59) of 0.2% for the plastic viscosity and an underestimation of 0.8% for the yield stress. For power-law fluids, the errors are of the same order of magnitude (i.e., negligible).

It can be shown that we can use torques and rotational speeds for other rheological models that are used to describe the behavior of cement slurries (e.g., Casson, Robertson and Stiff, Herschel-Bulkley). With the narrow-gap approximation, the shear-rate and shear-stress values could then be calculated from the following rather than Eqs. 4-18 to 4-20. \(\Omega\) is rotational velocity, and \(\theta\) is the viscometer reading.

\[
\dot{\gamma}_{ng} = 15.26 \times \Omega \quad (4-60)
\]

where \(\Omega\) is in rad/s, or

\[
\dot{\gamma}_{ng} = 1.598 \times \Omega \quad (4-61)
\]

where \(\Omega\) is in rpm.

\[
\tau_{ng} = 0.478 \times \theta \quad (4-62)
\]

where \(\tau_{ng}\) is in Pa and

\[
\tau_{ng} = 0.9984 \times \theta \quad (4-62)
\]

where \(\tau_{ng}\) is in lbm/100 ft^2. Eqs. 4-61 and 4-62 are written to correspond with standard spring F1.

4-3.5 What about the rheological model?

It is now well recognized throughout the industry that both the power-law model and the Bingham plastic model suffer from serious limitations when describing the rheology of drilling fluids, spacers, and cement slurries over a wide shear-rate range. The most commonly used alternative to these two parameter models is the Herschel-Bulkley model. It does not suffer from the same limitations; however, at this writing the Herschel-Bulkley model is not officially recognized in the API/ISO standards.
When the narrow gap approximation applies, determining the Herschel-Bulkley model parameters becomes easier. After converting the rotational speeds and torque readings to shear rates and shear stresses using Eqs. 4-18 to 4-20, or preferably Eqs. 4-60 to 4-62, an estimated fluid yield stress, \( \tau_y^{\text{est}} \), is used. A good starting point is 80% of the measured shear stress at 3 rpm. The shear-stress reading at 3 rpm is the lowest that is measured; therefore, it is closest to the fluid yield stress. The corresponding values of the power-law index, \( n \), and consistency index, \( k \), are determined by performing a linear regression analysis on the logarithm of the shear rates and the logarithm of the difference between the measured shear stresses and the assumed yield stress:

\[
\left\{ \log(\dot{\gamma}_{ny}); \log\left[ \left( \tau_{ny} \right)_{\text{data}} - \left( \tau_y \right)_{\text{calc}} \right] \right\}.
\]

Then the sum of the squares of the deviations is determined.

\[
\Delta = \sum \left[ \left( \tau_{ny} \right)_{\text{data}} - \left( \tau_{ny} \right)_{\text{calc}} \right]^2 \tag{4-63}
\]

The procedure then consists of choosing the yield-stress value that minimizes \( \Delta \), which is usually easy to do (Klotz, 1998). For the example given in Table 4-2, the rheological parameters calculated according to Eqs. 4-18 to 4-20 are

- \( \tau_y = 2.65 \text{ Pa} \)
- \( n = 0.902 \)
- \( k = 0.169 \text{ Pa-s}^n \).

The same parameters calculated according to Eqs. 4-60 to 4-62 are

- \( \tau_y = 2.48 \text{ Pa} \)
- \( n = 0.902 \)
- \( k = 0.168 \text{ Pa-s}^n \).

The improved performance of the Herschel-Bulkley model versus the power law and Bingham plastic models at low shear can be clearly seen in Fig. 4-21. Comparing the relative errors between the calculated and measured shear stresses (presented in Table 4-6) and those presented in Table 4-4 confirms the improved performance of the Herschel-Bulkley model over the entire shear-rate range.

### 4-3.6 End effects

In the equations developed in Section 4-3.1, the torque per unit length of any cylindrical surface with radius \( r \) is assumed to be known. However, because coaxial cylinder viscometers have a finite length, the shear flow in the annular gap where torque is measured is not homogeneous. The flow pattern is significantly modified close to the top and the bottom of the gap. In addition, the fluid that is sheared above and below the inner cylinder contributes to the measured torque. Such end effects are often assumed to be proportional to the undisturbed stress, and an extra cylinder length or a torque correction factor allows them to be taken into account. This factor is usually measured for Newtonian fluids and applied to all fluids without regard to which rheological model is most appropriate. A more reliable procedure consists of performing the measurements with different levels of fluid in the gap. For each rotational speed, the measured torque is a linear function of the fluid height in the gap, and the slope is the torque per unit length.

With standard oilfield equipment, the end correction factor recommended by manufacturers is 1.064. That factor is in fact hidden in the spring calibration con-

**Table 4-6. Relative Shear-Stress Errors Between Herschel-Bulkley Model and the Measured Data**

<table>
<thead>
<tr>
<th>Velocity (rpm)</th>
<th>Herschel-Bulkley Error (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>300</td>
<td>0.2</td>
</tr>
<tr>
<td>200</td>
<td>-0.7</td>
</tr>
<tr>
<td>100</td>
<td>0.9</td>
</tr>
<tr>
<td>60</td>
<td>0.9</td>
</tr>
<tr>
<td>30</td>
<td>-1.7</td>
</tr>
<tr>
<td>6</td>
<td>-1.4</td>
</tr>
<tr>
<td>3</td>
<td>2.0</td>
</tr>
</tbody>
</table>

*Relative error = \( \frac{\text{Calculated shear stress}}{\text{Measured shear stress}} \) – 1*
stant,\(^{12}\) which is 1.064 times lower than the nominal constant. This value is in agreement with measurements performed on Newtonian oils by Mannheimer (1988) and by the author. However, in 1987 Denis and Guillot found that end effects can account for up to 16% of the measured torque when testing cement slurries (Fig. 4-22), indicating that the current standard procedure can overestimate shear stresses by up to 10%.

Unfortunately, there is no clear understanding today of how end effects vary with the non-Newtonian behavior of fluids; therefore, no simple systematic procedure can be proposed. Nevertheless, when trying to compare results obtained with different instruments, one must be aware that end effects can account for differences in measured shear stresses.

4-3.7 Homogeneity of the cement slurry and wall slip

The flow equations in Section 4-3.1 also assume the fluid to be homogeneous in the annular gap. Because cement slurries are concentrated suspensions, they can only be considered homogeneous if the annular-gap size is at least 10 times that of the largest particles. In view of the particle-size distribution of cement powder, the gap size should be approximately 1 mm, which is the case with the standard oilfield geometry. Strictly speaking, what should be considered is the size of particle aggregates, a quantity which is much more difficult to determine. In the absence of quantitative information, rheological measurements should be performed with different gap sizes. If the experimental data are dependent upon the gap size, the homogeneity of the fluid is questionable.\(^{8}\)

Several authors (Tattersall, 1973; Mannheimer, 1983 and 1988; Lapasin et al., 1983; Denis and Guillot, 1987; Haimoni, 1987) have shown that cement slurries are indeed not homogeneous, particularly at low shear rates (Fig. 4-23). The correct interpretation of this effect is a very involved procedure.

\[ \Omega = \frac{1}{2} \int \frac{\dot{\gamma}}{\tau} \, d\tau + \frac{v_{\text{slip}}(r_1)}{r_1} + \frac{v_{\text{slip}}(r_2)}{r_2}. \] (4-64)

Assuming that the slip velocity depends only on the shear stress at the wall for a constant shear stress at the outer cylinder surface (Mooney, 1931),

\(^{12}\)Because the end correction factor is embedded in the spring calibration constant, the same factor is applied regardless of the coaxial cylinder geometry used, which is obviously not correct. So when changing the rotor and bob combination on the standard oilfield viscometer, it is recommended to experimentally determine the associated end correction factor.

\(^{8}\)When testing a suspension exhibiting a yield stress, like a spacer or a cement slurry in a coaxial cylinder viscometer, as the imposed shear rate decreases, part of the fluid becomes unsheared and the size of the sheared layer becomes smaller and smaller (Section 4-3.1). Therefore there is always a critical shear rate below which the suspension can no longer be considered a continuous medium.
Therefore, the effect of wall slip could be accounted for by performing experiments with different inner-cylinder radii. This analysis, which has been simplified by Mannheimer (1982) for narrow annular gaps and by Yoshimura and Prud’homme (1988), has not been conclusively validated for cement slurries. As can be seen in Fig. 4-24, the percentage of the flow caused by slip does not vary consistently with shear stress.

Using data affected by slippage at the wall, if the influence is not detected, can lead to erroneous conclusions concerning the behavior of the test fluid at low shear rates. For example, if one fits the data measured with the cement formulation presented in Table 4-7 to a power-law or Herschel-Bulkley model, relatively good results are obtained over the entire shear-rate range. This is shown graphically in Fig. 4-25. One could conclude that the fluid exhibits a very low yield stress or even no measurable yield stress. However, rerunning the test with a wider gap would show that the data measured at 5 and 10 sec⁻¹ (3 and 6 rpm) with the standard annular gap are affected by slippage at the wall and, therefore, should not be used to characterize the rheological properties of the fluid.

### Table 4-7. Viscometer Readings for a Cement Slurry†

<table>
<thead>
<tr>
<th>Rotational Speed (rpm)</th>
<th>Average Dial Readings</th>
</tr>
</thead>
<tbody>
<tr>
<td>300</td>
<td>68</td>
</tr>
<tr>
<td>200</td>
<td>58</td>
</tr>
<tr>
<td>100</td>
<td>47</td>
</tr>
<tr>
<td>60</td>
<td>41</td>
</tr>
<tr>
<td>30</td>
<td>36</td>
</tr>
<tr>
<td>6</td>
<td>19</td>
</tr>
<tr>
<td>3</td>
<td>12</td>
</tr>
</tbody>
</table>

† Measurement was performed with the standard R1B1 geometry and standard spring F1.

In a first series of tests, Mannheimer (1982) found the effect of slip velocity to be negligible above a given shear stress. Later, using different cements, conflicting results were obtained. The coaxial cylinder viscometer data, corrected for wall slip, did not agree with laminar friction-pressure data in large-diameter pipes (Mannheimer, 1988).

Another approach to minimize wall slip is to use grooved cylindrical surfaces. However, the reliability of the procedure with cement slurries is questionable, because the measured shear stresses depend on the depth of the serrations (Haimoni, 1987).

Haimoni (1987), tried to combine these two approaches (i.e., varying the gap size and the surface roughness of the cylinders) while making measurements on the same material. Although he was not able to propose a method to account for apparent slippage at the wall, he concluded that, once plug flow is eliminated, this phenomenon seems to have negligible consequences upon measurements performed in a coaxial cylinder viscometer.
Thus, without a proven method for preventing or accounting for wall slip, coaxial-cylinder-viscometer data that are affected by this phenomenon should not be used when trying to determine rheological parameters. It is the author's experience that these data points can often be detected on a log-log plot of the torque and rotational speed, which usually shows a drastic change in curvature (e.g., between 6 and 30 rpm for data presented in Table 4-7 (Fig. 4-26).

Frequently, experimental data falling below this breaking point are affected by wall slip. One can check this assumption by rerunning the test with a different gap size. The consequences of using data that are affected by wall slip can be quite important. In the particular example of the data presented in Table 4-7, the calculated yield stress of the cement slurry using the Herschel-Bulkley model varies from less than 1 Pa when the 3- and 6-rpm data are used to nearly 13 Pa when they are not.

4-3.8 Particle migration

Particle migration caused by gravitational or centrifugal forces may also affect the rheological measurements. For the results to be meaningful, the test fluid should not segregate during the measurement. Before measuring the rheological properties of a cement slurry, it is essential to ensure that particle segregation does not occur under static conditions (leading to free water and sedimentation). Unfortunately, this does not necessarily mean that particle segregation will not occur under dynamic conditions, because

- the viscosity of the fluid usually decreases with shear
- under dynamic conditions, the centrifugal forces can be greater than the gravitational forces.

Using a transparent rotor and a transparent beaker, and adding small black tracer particles to a Newtonian fluid or polymer solution, Meeten and Pafitis (1993) were able to show that the tracer particles migrated in the annular gap of a coaxial-cylinder viscometer because of gravitational and/or centrifugal forces. Meeten and Pafitis also noticed that, when sheared at relatively high rates, suspensions such as drilling fluids, spacers, or cement slurries sometimes required several minutes to reach a steady state: An unusually long shearing period was required before the viscometer dial reading was constant. Meeten and Pafitis attributed this time-dependent behavior to particle migration.

Standard oilfield equipment is designed so that these effects are not severe. But when using slurries that have a low viscosity at high shear rates, or when shearing slurries for a long period of time (e.g., during heat-up periods in a high-pressure, high-temperature [HPHT] rheometer), this problem may become significant. Different solutions have been proposed.

Meeten and Pafitis (1993) suggested using a pump to ensure better fluid homogeneity not only in the cup but also in the annular gap (Fig. 4-27).

Ravi and Sutton (1990) included an independent impeller at the bottom of the cup of a HPHT viscometer to better homogenize the slurry in the gap. The impeller rotates during the heat-up period and stops while rheological measurements are being taken.

An interesting approach for limiting particle migration effects, as well as the wall slip effect, was investigated by Vlachou and Piau (2000). The geometry of the rotational viscometer (Fig. 4-28) was modified to incor-
porate a series of grid tools combined in a multiple parallel plate configuration. The geometry seems particularly interesting for cement slurries exhibiting some settling under shear. The grids are placed in the bulk of the sample, and the particles can easily settle through the grids. This design minimizes the effect of particle settling on the rheological measurement. But this geometry has not yet gained industry recognition.

4-3.9 Testing slurries containing large particles

When a cement slurry contains a significant volume fraction of particles larger than 120 μm, the size of the standard annular gap must be increased for the slurry to be considered homogeneous. If this is not done, the measurements are likely to underestimate the true fluid viscosity.

One way to determine if this is indeed a problem is to perform the same rheological measurements with different gap sizes. If the measured shear stresses are gap-size dependent, the gap should be widened until this is no longer the case. In practice, using a gap much larger than 3 to 4 mm with the standard oilfield viscometer does not work well for several reasons. As the gap size increases, the following effects occur:

- The shear-rate range of the test is shifted towards lower values; consequently, the measured torques become smaller and less accurate.
- The shear rate and shear stress become less homogeneous across the gap, and the likelihood of obtaining plug flow at low velocities increases. This requires some precautions when analyzing and fitting the data to a rheological model.
- Particle migration becomes more and more influential.
- Instabilities like Taylor vortices (deviations from laminar flow) may be present at high rotational speeds when the inner cylinder rotates (e.g., with some HPHT viscometers).

4-3.10 Foamed cement

Cement slurries can be foamed with air or nitrogen, as explained in Chapter 7. Foamed cement is usually characterized by its quality, defined as the volume of gas per unit volume of slurry. The quality of a foamed cement during placement in the wellbore rarely exceeds 70%. This is the lower limit for a fluid to be technically considered to be foam. Nevertheless, in the well cementing industry, the term “foam” is used regardless of the quality.

Very little is known about foamed cement rheology other than that the apparent viscosity of foamed cement increases with quality. Al-Mashat (1976) used the Bingham plastic model to describe pipe flow of nitrogen-foamed cement up to Newtonian shear rates of 5,000 sec⁻¹. He found that the effect of foam quality, Q_{foam}, on the rheological parameters could be described by the equations below.

\[
\mu_p = 13.00021 - \left(71.336573 \times Q_{foam}\right) + \left[367.12431 \times \left(Q_{foam}\right)^2 - 257.9818 \times \left(Q_{foam}\right)^3\right]
\]  

\(4-66a\)

for \(0 \leq Q_{foam} \leq 0.65\)

\[
\tau_y = 16.2297 - \left(83.9824 \times Q_{foam}\right) + \left[146.36276 \times \left(Q_{foam}\right)^2\right]
\]  

\(4-66b\)

for \(0.35 \leq Q_{foam} \leq 0.65\)

where the plastic viscosities are in mPa-s and the yield stresses are in Pa.
Unfortunately, the rheology of the base slurry itself is not reported; therefore, these equations are of little practical interest other than for giving an idea of how much the apparent viscosity of the foam varies as a function of foam quality. If the plastic viscosity equation is valid at 0 foam quality, it shows that plastic viscosity varies by a factor of 3.6 when the foam quality increases to 60% from 0%.

Because of the lack of data on foamed cement, placement simulators (Purvis and Smith, 1994; Garcia et al., 1993) capable of handling foamed cements or spacers usually rely on empirical correlations that were developed by Reidenbach et al. (1986) with linear (i.e., uncrosslinked) polymer-base fracturing fluids. These authors assumed that the rheological behavior of foamed fracturing fluids can be described by the Herschel-Bulkley model. The effects of foam quality and temperature on the model rheological parameters are then described as follows.

\[ \tau_y = 3.35 \times Q_{foam} \text{ for } Q_{foam} \leq 0.6 \]
\[ \tau_y = 0.00958 \times \exp(9 \times Q_{foam}) \text{ for } Q_{foam} > 0.6 \]
\[ k = k_{bf} \times \exp \left( C_1 \times Q_{foam} + 0.75 \left( Q_{foam} \right)^2 \right) \]  \hspace{1cm} (4-67)

The consistency indices are expressed in Pa-s^n and the yield stresses in Pa.

The power-law index is assumed to be independent of foam quality. In these equations, \( k_{bf} \) is the consistency index of the base fracturing fluid used to prepare the foam; \( C_1 \) is a constant that depends on the power-law index of the base fluid. Harris and Reidenbach (1987) later refined this model to account for the effects of foam quality and temperature on the rheological parameters. Such equations cannot be used directly for cement slurries, but they provide an order of magnitude of the effect of foam quality on the apparent viscosity. For example, the constants \( k_{bf}, C_1, \) and \( n \) are such that the apparent viscosities of foamed fracturing fluids (linear gels) in a 100 to 1,000 sec^{-1} range increase by a factor between 2.8 and 7.8 when the foam quality increases to 60% from 0%.

This range of relative viscosities is consistent with the values calculated by Al-Mashat (1976) on foamed cement. It is also clear from Harris and Reidenbach (1987) that base fluids with higher polymer concentrations are more shear thinning. As a result, the relative viscosity of the foam does not increase as quickly with quality. From these data, it is difficult to determine how the yield stress of a foamed cement slurry is affected by foam quality. Unlike cement slurries, linear fracturing-fluid gels do not exhibit a true yield stress.

### 4-3.11 Cement rheology measured with different equipment

When attempting to characterize the rheological behavior of fluids as complex as cement slurries, it is essential to ensure that the measurements are not equipment dependent. Thus, several authors have compared rheological measurements performed with different types of equipment, usually a coaxial cylinder viscometer and a pipe viscometer. For such a comparison to be significant, it must be performed within a shear-rate range common to both apparatuses.

Denis and Guillot (1987) showed that, with some cement-slurry formulations, reasonable agreement can be obtained between a pipe viscometer and a specific coaxial cylinder viscometer, provided the rheological data are not affected by wall slip (Fig. 4-29).

However, when cement slurries are characterized with the standard oilfield viscometer, the results often differ from those obtained with pipe viscometers, even when using large-diameter pipes to minimize the effects of apparent wall slip (Bannister, 1980; Mannheimer, 1983; Denis and Guillot, 1987).

In an attempt to solve this problem, Shah and Sutton (1989) tried to obtain a statistical correlation between the measurements performed with a standard oilfield viscometer and a pipe viscometer. They used a modified coaxial-cylinder viscometer that allowed vertical circulation of the slurry in the annular gap. Circulation was stopped while taking a measurement at a given rota-
tional speed. For a wide variety of cement-slurry formulations, they compared the rheological parameters by fitting experimental data from their modified viscometer

\[ [\mu_p]_c \cdot [(\tau_y)_c]\]

and a pipe-flow loop

\[ [\mu_p]_p \cdot [(\tau_y)_p]\]

to the Bingham plastic model. They found the following correlation for the plastic viscosities when expressed in centipoise (Fig. 4-30).

\[ \mu_p \cdot \tau_y = 0.962 \times [(\mu_p)_c]^{0.9815}, \quad (4-68) \]

indicating that the plastic viscosities obtained with the pipe viscometer were about 10% lower than those obtained with the coaxial-cylinder viscometer.

The pipe- and coaxial-cylinder viscometers overestimated the yield stresses by factors of 1.333 and 1.067, respectively (Fig. 4-31). In both cases, the shear rate at the wall was assumed to be Newtonian, which is not the case for a Bingham plastic fluid. Therefore, once the yield stresses are corrected, the correlation of Shah and Sutton (1989) becomes

\[ (\tau_y)_p = 1.273 \times (\tau_y)_c - 1.611 \quad (4-69) \]

where the yield stresses are expressed in lbf/100 ft². This equation indicates that the yield stresses obtained with the pipe viscometer were between 0% and 27% greater than those obtained with the coaxial-cylinder viscometer. This empirical procedure is quite useful, but it suffers from one limitation: the cement slurries are assumed to follow the Bingham plastic model, which is not necessarily the case.

4-4 Pressure, temperature, and time dependency

The pressure and temperature dependence of the rheological properties of cement slurries is not always properly investigated, because the standard oilfield equipment allows measurements to be performed only at atmospheric pressure and at temperatures below about 185°F [85°C]. Limited studies at higher temperatures suggest that cement-slurry stability can be problematic.

4-4.1 Temperature dependency

Temperature can substantially affect the rheological properties of cement slurries, but the extent is highly dependent on the cement slurry rheology and the additives in the formulation. The differences in temperature dependence are shown in Figs. 4-32 and 4-33.

The first formulation contains a water-soluble polymer (hydroxyethylcellulose) that viscosifies the interstitial water and contributes significantly to the slurry viscosity. Because the solution viscosity of the polymer itself is temperature sensitive, the plastic viscosity of the slurry follows the same continuous downward trend, while the yield stress remains almost constant.

The behavior of the second system (containing a dispersant and latex) is more complicated. The plastic vis-
Viscosity of the slurry first decreases by a factor of 2 between 77 and 113°F [25 and 45°C], then increases more slowly from 113 to 185°F [45 to 85°C]. Meanwhile, the yield stress increases slowly but continuously throughout the temperature range investigated.

These two examples illustrate that there is currently little hope of finding a general model to describe the temperature dependence of the cement-slurry rheology. Limiting the investigation to cement systems containing specific additives, a general data trend was observed by Ravi and Sutton (1990). Using the Bingham plastic model to fit the rheological data, they were able to show that the variation in the rheological parameters with temperature could be described by the following equations, in which the plastic viscosity and yield value were measured at 80°F [27°C].

\[
\mu_p (T) = a + (b \times T) + \left(0.00325 \times T^2\right),
\]

where \( \mu_p \) is in mPa-s and \( T \) is in °F, and
\[
a = 65.0729 + 1.3054 \times \mu_p \text{ at } 80°F
\]
\[
b = 1.0734 - 0.00381 \times \mu_p \text{ at } 80°F.
\]

\[
\tau_y = a' + (b' \times T) + \left(0.002 \times T^2\right),
\]

where \( \tau_y \) is in lbf/100 ft² and \( T \) is in °F, and
\[
a' = 36.651 + 1.4047 \times \tau_y \text{ at } 80°F
\]
\[
b' = -0.61813 - 0.00505 \times \tau_y \text{ at } 80°F.
\]

Each of these equations is limited to a maximum temperature, \( T_{\text{max}} \). Above this limit, the plastic viscosity or the yield stress is considered to be constant (otherwise these factors would increase with temperature).

For spacers, the temperature dependency is usually somewhat simpler because spacers are usually composed of water, salts, water-soluble polymers, clays, and weighting agents. Figure 4-34 is a typical example showing how the viscosity of a water-base spacer varies with temperature (Théron et al., 2002).

In this particular case, the data were fitted to the Herschel-Bulkley model; however, the parameters of this model do not show a simple trend with temperature. Therefore, interpolating data at various temperatures from this type of measurement is usually performed in a different way. For each shear rate used to build the different rheograms, a virtual shear stress is determined at a given temperature using an interpolation of the measured shear stresses as a function of temperature. These virtual shear stresses are then fitted to the Herschel-Bulkley model. A more sophisticated approach, using a neural network model, has been used by Théron et al. (2002) to describe how spacer viscosity is affected by temperature, chemical composition, and density.

In the absence of a specific model to describe how the rheological properties of a given spacer or cement slurry are affected by temperature, one should perform the measurements at three different temperatures at least, covering the range the fluid will encounter during the operation. As explained above, for a given shear rate, shear stresses can then be interpolated as a function of temperature and a shear-stress/shear-rate diagram can be rebuilt for each temperature before fitting the data to a rheological model.
4-4.2 Pressure dependency

The effect of pressure on the rheological properties of spacers or cement slurries is often ignored because, under dynamic conditions, this effect seems to be small when compared to the effect of temperature. Pressure effects can be accounted for by an apparent increase in the solid volume fraction (SVF) owing to the higher compressibility of the liquid phase versus the solid phase. For a Class G cement slurry mixed at 15.8 lbm/gal [1,893 kg/m³], assuming the densities of the mix water and the cement powder are 8.33 lbm/gal [1,000 kg/m³] and 26.6 lbm/gal [3,200 kg/m³], the SVF is 40.6%. Assuming the isothermal compressibility of the liquid phase is 4 × 10⁻¹⁰ Pa⁻¹, and neglecting that of the solid phase, the SVF increases to only 40.7%, and the slurry density increases to 15.84 lbm/gal [1,900 kg/m³] at 10 MPa. At 100 MPa, the SVF is 41.6% and the slurry density is 16.18 lbm/gal [1,939 kg/m³].

During a cementing operation, the slurry-density control is ±0.2 lbm/gal [0.024 kg/m³] at best. Therefore, unless the slurry contains compressible or pressure-sensitive additives (e.g., ceramic microspheres) the effect of pressure should be negligible.

Laboratory measurements show ambiguous results, even when they are not performed close to the end of the thickening time. Pressure affects the thickening time and compressive strength development. Kellingray et al. (1990) determined the apparent viscosities of two specific cement slurries measured at 511 sec⁻¹ and about 230°F [110°C]. The viscosity of the first slurry increased by 8% as the pressure increased to 5,870 psi [40.5 MPa]. The viscosity of the second slurry increased by 25% as the pressure increased to 11,800 psi [81.1 MPa]. With another cement system, Cartalos et al. (1994) did not see a detectable effect of pressure from 100 to 11,600 psi [0.7 to 80 MPa] at 248°F [120°C]. These results seem inconsistent because the cement systems have nearly the same density (15.8 lbm/gal [1,900 kg/m³]), and they have approximately the same solid volume fraction. The only differences were the choice of retarder, choice of fluid-loss additive, and the type of instrument used to measure the rheological properties. Further investigation is necessary to quantify the effect of pressure on the rheological behavior of cement systems.

4-4.3 Time dependency under shear

Spacers and cement slurries sheared in a coaxial cylinder viscometer may exhibit time-dependent behavior. As discussed earlier, this apparent time dependency can be an artifact caused by particle migration. However, the material may be exhibiting a truly time-dependent behavior. This is more common for cement slurries than for spacers. There are two main reasons for the time dependency of cement slurries. First, these slurries contain colloidal charged particles that may cause a thixotropic (reversible) behavior. Second, they are chemically reactive suspensions that are irreversibly affected by time.

The API/ISO procedure is not very well adapted to detect thixotropic behavior, but, when the time scales associated with its structural buildup and breakdown are not too short, an open hysteresis cycle may indicate true time-dependent behavior. Usually, when cement slurries that are not designed to be thixotropic are sheared for periods longer than 20 sec, and particle migration is avoided, the stress response depends on the amount of applied shear. At relatively high shear rates, the measured shear rate stabilizes relatively quickly within less than 20 sec (Fig. 4-35). This behavior supports the time step adopted as an industry standard procedure. At lower shear rates, shear stress tends to increase with time towards an asymptotic value, indicating that the suspension undergoes a structural buildup.

It is possible to show that this behavior is usually reversible within several minutes. It can therefore be qualified as thixotropic. When the applied shear rate is extremely low, a steady flow does not necessarily occur (Vlachou, 1996). The measured stress may then continuously increase over long time periods, as will be discussed below.†††

††† Other phenomena such as wall slip and fracturing of the material can be observed (Vlachou, 1996).
When observing the behavior of cement slurries over longer time scales—a significant fraction of the thickening time—cement slurries may exhibit an irreversible behavior caused by the ongoing chemical reactions that modify the characteristics of the suspension. For example, the rheological behavior of a cement slurry at a specific temperature (Fig. 4-36) can vary significantly as a function of the conditioning time (i.e., how long the slurry is sheared at temperature before performing the rheological measurement).

This time dependency raises questions concerning the procedures used to measure cement-slurry properties, because the measurements are merely a “snapshot” of the behavior as it evolves with time. When performing simulations of the placement process, and when rheology has a significant impact on the results, it is important to ensure that the rheology data are representative of the operation. The time and temperature history may need to be considered for the simulations to be meaningful.

4-4.4 Gel strength measurements

The rheological behavior of cement slurries at rest is one of the factors that govern formation-fluid migration into the annulus after a primary cementing operation (Chapter 9). Therefore, the industry has developed several techniques to better characterize the yield stress of cement slurries at rest. This is called the gel strength.

Following the standard procedure defined by the API/ISO for drilling muds, gel strengths of cement slurries are often evaluated by measuring the peak value of the torque upon sudden application of a shear rate of 5.11 sec⁻¹ after a given rest period. Unfortunately, for two main reasons, the results obtained with this experimental method are questionable.

- It has already been mentioned that the low-shear behavior of cement slurries is very often affected by wall slip. This is especially true for thixotropic systems, because most experimental results show that the higher the yield stress of the fluid, the larger the shear-rate range affected by wall slip.

- The results obtained may vary from one piece of equipment to another, depending on the inertia of the fixture and on the spring stiffness of the measuring device.

With standard oilfield equipment, little can be done to address the second point. Even in the absence of wall slip (e.g., with drilling muds), gel strength values can be underestimated (Speers et al., 1987). Therefore, other techniques have been considered.

Sabins et al. (1980) developed a device to measure the gel strength of cement slurries. Derived from a pressurized consistometer (Appendix B), their device measures the torque necessary to rotate a specific paddle at a low rate. However, the stress distribution in this device...
is not known, and it is not entirely clear whether the instrument is measuring a fluid “consistency” that would correlate with the true gel strength or whether it is measuring a stress at the interface between the cement sample and the sample cup. Nevertheless, Sabins et al. (1980) were able to show some correlation between their gel strength measurements and friction pressure measurements performed at low shear rates.

To ensure that the measured rheological characteristics are valid and not an artifact of friction between the instrument and slurry, other authors have used the shear-vane method. The standard coaxial cylinder is replaced by a vane (Fig. 4-37).

If the vane is rotated at a sufficiently low speed, the sheared surface is cylindrical. The maximum torque recorded can be used to calculate the gel strength of the material (Banfill and Kitching, 1990). The advantage of this method, which is commonly used in soil mechanics, is that results are not affected by wall slip because the shear surface is within the material itself.

More recently, Moon and Wang (1999) derived cement-slurry gel strength by measuring the attenuation of acoustic waves propagating through the tested material. They correlated the measured attenuation and cement-slurry gel strength measurements performed at low shear in a pipe (Section 4-3.11) or a shearometer tube. A shearometer tube is a hollow cylinder that is placed vertically on top of the fluid to be analyzed. The cylinder is allowed to sink into the fluid until its position stabilizes. The gel strength is determined from the cylinder geometry and weight, the depth to which the cylinder sank into the material, and the fluid density. The advantage of these methods is that the sample is submitted to extremely small deformations. The drawback is that it relies on a correlation that may not apply to a wide range of cement systems.

The structural buildup of a cement slurry can also be followed through oscillatory dynamic tests, measuring the evolution of the storage (elastic) and loss (viscous) moduli over time (Hannant and Keating, 1985; Chow et al., 1988), but these techniques do not give direct access to the gel strength.

These different techniques do not produce the same results on the same cement slurry. Therefore, more work will be required to understand these differences, in hopes that the industry will eventually be able to standardize equipment and procedures to measure gel strength. In the meantime, when reporting gel strength data, it is essential to specify the equipment and procedure used to perform the measurements.

4-5 Flow of spacers and cement slurries in the wellbore

The previous sections showed how the rheological properties of spacers and cement slurries are characterized. This section examines how this information is used to determine velocity profiles, circulation efficiency, and friction pressures of spacers and cement slurries. The following also applies to drilling fluids.

4-5.1 Generic laminar flow equations

The axial flow of a fluid in a concentric annulus between two cylinders of radii \( r_o \) and \( r_w < r_o \) is considered. It is assumed that the fluid is incompressible and inelastic. Provided the flow is laminar,\(^\text{111}\) steady, and isothermal, the \( z \) component of the equation of motion along the axis of symmetry reduces to (Bird et al., 1960)

\[
\frac{1}{r} \frac{d}{dr} \left( r \tau_{rz} \right) = -\frac{d p_{\text{mod}}}{dz},
\]

(4-72)

where

\( g_z = z \) component of gravity

\( p = \) total pressure

\(^{111}\) Flow regimes are discussed in Section 4–6.2. For the time being, the fluid particles are assumed to flow along streamlines that are parallel to the main direction of flow.
\(p_{\text{mod}}\) = modified pressure, given by \(p_{\text{mod}} = p + \rho g z\)

\(r\) = radial distance from the symmetry axis such that \(r_w < r < r_o\)

\(\rho\) = fluid density

\(\tau_{rz}\) = \(rz\) component of the stress tensor (shear stress).

Eq. 4-72 can be integrated for any kind of fluid.

\[
\tau_{rz} = \frac{1}{2} \frac{dp_{\text{mod}}}{dz} \left( r - \frac{\lambda r_o^2}{r} \right), \quad (4-73)
\]

where \(\lambda r_o\) is the radial position at which \(\tau_{rz} = 0\).

Because

\[
\tau_{rz} = \mu \left( \frac{dv}{dr} \right) \times \frac{dv}{dr} = \mu \left( \frac{dv}{dr} \right) \times \frac{dv}{dr}, \quad (4-74)
\]

then

\[
\mu \left( \frac{dv}{dr} \right) \times \frac{dv}{dr} = -\frac{1}{2} \frac{dp_{\text{mod}}}{dz} \times \left[ r - \frac{\lambda r_o^2}{r} \right], \quad (4-75)
\]

where \(\mu\) = viscosity of the fluid

\(\dot{\gamma}_{rz}\) = \(rz\) component of the rate-of-strain tensor (shear rate).

This general expression is used for various flow situations relevant to the wellbore geometry.

4-5.1.1 Pipe flow

For the particular case of a pipe of radius \(r_w\) (or diameter \(d_w\)), \(\lambda = 0\). Using Eq. 4-73, the shear-stress profile varies linearly from 0 along the symmetry axis to a maximum value at the wall \(\tau_w\).

\[
\tau = \tau_{rz} = -\frac{r}{2} \frac{dp_{\text{mod}}}{dz} = \frac{r}{r_w} \tau_w = \sigma \tau_w \quad (4-76)
\]

Equation 4-75 reduces to

\[
\mu \left( \frac{dv}{dr} \right) \times \frac{dv}{dr} = -\frac{r}{2} \frac{dp_{\text{mod}}}{dz}. \quad (4-77)
\]

Integrating from the radius \(r\) to the wall (\(r = r_w\)), and assuming the velocity at the wall is 0, one obtains a general expression for the velocity at a distance \(r\) from the pipe axis.

\[
v(r) = -\frac{2}{\mu} \frac{dp_{\text{mod}}}{dz} \int_{r_w}^{r} \tau \, dt - \frac{r_w}{\tau_w} \int_{r_w}^{r} \dot{\gamma} \, dt. \quad (4-78)
\]

The volumetric flow rate, \(q\), or the mean velocity, \(\overline{v}\), of the fluid (i.e., the volumetric flow rate per unit cross-sectional area) can be derived from the velocity profile through an integration by parts, and rearranged to give

\[
4q = \frac{4\overline{v}}{(r_w)^3} = \frac{4}{\tau_w^3} \int_{0}^{\tau_w} \frac{\tau^2 \dot{\gamma} \, d\tau}{\mu}. \quad (4-79)
\]

If the fluid exhibits a yield stress, \(\tau_y\), then the profile is flat around the pipe axis and the constant velocity is given by

\[
v(r) = -\frac{r_w}{\tau_w} \int_{\tau_y}^{\tau_w} \dot{\gamma} \, d\tau \text{ when: } r = \frac{r_w}{\tau_w} \tau_y. \quad (4-80)
\]

The expression for the volumetric flow rate is slightly modified.

\[
\frac{4q}{\pi (r_w)^3} = \frac{4}{(r_w)^3} \int_{0}^{\tau_w} \tau^2 \dot{\gamma} \, d\tau \quad (4-81)
\]

A particularly useful form of Eq. 4-79 gives the expression for the shear rate at the wall, \(\dot{\gamma}_w\).

\[
\dot{\gamma}_w = \frac{3n' + 1}{4n'} \frac{\overline{v}}{r_w} = \frac{3n' + 1}{4n'} \frac{8\overline{v}}{d_w} = \frac{3n' + 1}{4n'} \frac{32q}{\pi (d_w)^3}, \quad (4-82)
\]

where

\[
n' = \frac{d \log (\tau_w)}{d \log (\frac{4\overline{v}}{d_w})} = \frac{d \log (\tau_w)}{d \log (8\overline{v})}. \quad (4-83)
\]

From now on, the term

\[
\frac{dp_{\text{mod}}}{dz}
\]

will be replaced by

\[
\left( \frac{dp}{dz} \right)_f = -\frac{dp_{\text{mod}}}{dz}
\]
to recognize the fact that this pressure loss is caused by friction and to avoid using a negative sign in the following equations.

For a Newtonian fluid, the pipe-flow equations are

\[
\dot{\gamma} = 4\frac{\bar{v}}{r_w} \frac{r_p}{r_w} = \frac{r}{r_p} \dot{\gamma}_{NW} \quad (4-84) \\
\frac{v(r)}{\bar{v}} = 2 \left[ 1 - \left( \frac{r}{r_w} \right)^2 \right] \quad (4-85) \\
\left( \frac{dp}{dz} \right)_f = \frac{32\mu\bar{v}}{(d_w)^2} = \frac{128\mu q}{\pi(d_w)^4} \quad (4-86)
\]

Notice that, for Newtonian fluids, the shear-rate profile varies linearly from zero at the pipe axis to a maximum value at the pipe wall (Fig. 4-38). The velocity profile is independent of the fluid viscosity and flow rate. Friction pressure is proportional to the fluid viscosity and flow rate. It is inversely proportional to the fourth power of the pipe diameter. Therefore, friction pressures are extremely sensitive to pipe diameter when compared to fluid viscosity and flow rate.

For a power-law fluid, the corresponding equations are

\[
\dot{\gamma} = 3n + 1 \frac{4\bar{v}}{4n} \frac{r}{r_w} \frac{1}{n} = \frac{3n + 1}{4n} \left( \frac{r}{r_w} \right)^{n+1} \dot{\gamma}_{NW} \quad (4-87) \\
\frac{v(r)}{\bar{v}} = \frac{3n + 1}{n+1} \left[ 1 - \left( \frac{r}{r_w} \right)^{n+1} \right] \quad (4-88) \\
\left( \frac{dp}{dz} \right)_f = \frac{4k}{d_w} \frac{3n + 1}{4n} \frac{8\bar{v}}{d_w} = 2^{3n+2} k_{pipe} q^n \quad (4-89)
\]

![Fig. 4-38. Normalized velocity- and shear-rate profiles for Newtonian and power-law fluids flowing in a pipe \( n = \text{power-law index} \) \( n = 1.00 \) for Newtonian fluids. The reduced abscissa represents the distance to the axis of the pipe divided by the pipe radius \( i.e., r/\sqrt{r} \) in Eq. 4-85. Particle velocity is normalized by the fluid mean velocity. Shear-rate values are normalized by the Newtonian shear rate at the wall.](image-url)
where \( k_{\text{pipe}} \) is often referred to as the pipe consistency index, defined by

\[
k_{\text{pipe}} = \left( \frac{3n+1}{4n} \right)^n k. \tag{4-90}
\]

Notice that, for power-law fluids, the shear-rate profile follows a power-law curve. The shear rate is 0 at the pipe axis and reaches a maximum at the pipe wall (Fig. 4-38). The velocity profile is independent of the fluid consistency index and the flow rate. It depends only on the power-law index. The lower the power-law index (the less Newtonian the fluid is), the flatter the velocity profile (Fig. 4-38). The friction pressure is proportional to the consistency index and the flow rate to the power \( n \). It is inversely proportional to the \((3n+1)^{\text{power of the pipe diameter}}\). Therefore, friction pressures are much more sensitive to the pipe diameter than the flow rate, regardless of the power-law index value.

For Bingham plastic fluids, the flow rate/friction pressure relationship can be described by what is known as the Buckingham-Reiner equation.

\[
\psi = \sqrt{M + P - 2(M^2 + P^2 - MP)^{1/4}} \cos \left( \frac{\theta}{2} \right)
\]

\[
\theta = \arccos \left[ \frac{-(M + P)}{2\sqrt{M^2 + P^2 - MP}} \right]
\]

\[
M = \frac{1}{2} \left[ \left(1 + \frac{2\zeta}{4}\right) + \sqrt{\left(\frac{1 + \frac{2\zeta}{4}\right)^2 - 1} \right]^{1/3}
\]

\[
P = \frac{1}{2} \left[ \left(1 + \frac{2\zeta}{4}\right) - \sqrt{\left(\frac{1 + \frac{2\zeta}{4}\right)^2 - 1} \right]^{1/3}
\tag{4-93}
\]

Eq. 4-91 shows that friction pressures depend in a nonlinear fashion on flow rates (Fig. 4-39). But when the Newtonian shear rate is high compared to the ratio of the plastic viscosity to the yield stress, the relationship becomes nearly linear. The term to the fourth power in Eq. 4-91 can be neglected, leading to the following approximation.

\[
\psi = \frac{1}{\zeta^3} \tan \frac{\psi}{3} \tag{4-94}
\]

\[
\left( \frac{dp}{dz} \right)_f = \frac{16\tau_y}{3d_w} + \frac{128\mu p g}{\pi(d_w)^4} = \frac{16\tau_y}{3d_w} + \frac{32\mu p v}{(d_w)^2} \tag{4-95}
\]

This approximation can be made to determine friction pressures, provided the dimensionless shear rate, \( \bar{\tau} \), is sufficiently large. For example, if

\[
\frac{8\bar{\tau}}{\zeta^3} > 1.10,
\]

Eq. 4-95 will overestimate the friction pressures by less than 1%. The shear rate and velocity profile are given by two equations. Part of the velocity profile around the pipe axis is flat, while the rest of it is a parabola.
The shear rate is 0 in the center of the pipe, but then it varies linearly until it reaches a maximum value at the pipe wall (Fig. 4-40).

The velocity profile depends on a single parameter—either the dimensionless shear rate, 

\[ \xi = \frac{\mu_p}{\tau_y} \]

or the reciprocal dimensionless shear stress, \( \psi \)—because these two parameters are interrelated by Eq. 4-91.

This parameter embeds the roles of pipe diameter, fluid velocity (or flow rate) through the Newtonian shear-rate term, and the rheological parameters of the fluid through the plastic viscosity/yield stress ratio. When compared to the yield stress/plastic viscosity ratio, the lower the Newtonian shear rate is, the less Newtonian the fluid will be. The viscosity profile will also be flatter (Fig. 4-40). Thus, unlike that of power-law fluids, the velocity profile of Bingham plastic fluids is flow rate dependent.

The complete set of Herschel-Bulkley equations is given in Appendix A. The equation relating the flow rate to the friction pressure,

\[ \xi = \frac{8\bar{v}}{d_w} \times \left( \frac{k}{\tau_y} \right)^{\frac{1}{n}} = \frac{32q}{\pi (d_w)^3} \times \left( \frac{k}{\tau_y} \right)^{\frac{1}{n}} \]

\[ = \frac{4n(1-\psi)^{\frac{1}{n}}}{\psi^{\frac{1}{n}}} \times \left[ \frac{(1-\psi)^2}{3n+1} + \frac{2\psi(1-\psi)}{2n+1} + \frac{\psi^2}{n+1} \right] \]

must be solved numerically to determine the friction pressure for a given flow rate. As for Bingham plastic fluids, this equation relates a dimensionless shear rate, \( \xi \), to a reciprocal dimensionless shear stress, \( \psi \). An approximation to Eq. 4-98 can be used for large values of \( \xi \), or when \( \psi \) is small enough. This leads to the following explicit expression:

\[ \left( \frac{dp}{dz} \right)_f = \frac{16}{3} \frac{\tau_y}{d_w} + \frac{(3n+1)^n}{n} \frac{2^{n+2}k\bar{v}^n}{(d_w)^{n+1}} \]

Reviews of pipe-flow equations for other model fluids (Casson; Robertson and Stiff) were presented by Whittaker (1985) and Fordham et al. (1991).
4-5.2 Narrow concentric annular flow

As will be discussed later, when the radius ratio in an annulus is relatively close to unity, the flow equations can be reasonably well approximated by neglecting the curvature effect and using a parallel-plate approximation. Annular flow is then assumed to be equivalent to flow between parallel plates—a rectangular slot of infinite width—separated by a distance $L = (r_o - r_w)$. The actual width of the slot, $w = \pi (r_o + r_w)$, is only taken into account to convert the mean fluid velocity to flow rate, or vice versa. Expressions for the shear-stress profile, velocity profile, and volume flux can be easily derived in the same way as for a pipe, with $r$ now being the distance from the plane of symmetry of the slot.

\[
\tau = \tau_{rz} = \frac{r}{2} \left( \frac{dp}{dz} \right)_f = \frac{r}{L} \tau_w = \lambda \tau_w \quad (4-100)
\]

\[
v(r) = \left( \frac{dp}{dz} \right)_f \int_0^{\tau_w} \frac{\tau}{\mu} \left( \frac{dv}{dr} \right) \frac{d\tau}{\tau} = \frac{L}{2\tau_w} \int_{\tau(r)}^{\tau_w} \dot{\gamma} \ d\tau \quad (4-101)
\]

\[
\frac{6q}{wL^2} = \frac{6\bar{\tau}}{L} = \frac{3}{(\tau_w)^2} \int_0^{\tau_w} \frac{\tau^2}{\mu} \left( \frac{dv}{dr} \right) \ d\tau = \frac{3}{(\tau_w)^2} \int_0^{\tau_w} \bar{\gamma}(\tau) \ d\tau \quad (4-102)
\]

\[
\bar{\gamma}_w = \frac{2n' + 1}{3n'} \frac{6\bar{\tau}}{L} = \frac{2n' + 1}{3n'} \frac{12\bar{\tau}}{d_o - d_w} \quad (4-103)
\]

\[
n' = \frac{d\log(\tau_w)}{d\log(\frac{6\bar{\gamma}}{L})} = \frac{d\log(\tau_w)}{d\log\left(\frac{12\bar{\gamma}}{d_o - d_w}\right)} \quad (4-104)
\]

For fluids exhibiting a yield stress, $\tau_y$, the velocity profile is flat around the pipe axis, and the constant velocity is given by

\[
v(r) = \frac{L}{2\tau_w} \int_{\tau_y}^{\tau_w} \dot{\gamma} \ d\tau \text{ when } \frac{r}{L} \leq \psi = \frac{\tau_y}{\tau_w} \quad (4-105)
\]
The expression giving the volumetric flow rate is slightly modified.

\[
\frac{6q}{wL^2} = \frac{3}{(\tau_w)^2} \int_\tau^\infty \tau G(\tau) d\tau \tag{4-106}
\]

Because the flow equations for different rheological models look very similar to the ones described earlier for flow through a pipe, only a few of them are given here. The other ones will be found in Appendix A.

For power-law fluids, the main flow equation is

\[
\frac{dp}{dz}_f = 2^{n+2} \times 3^n \times k_{ann} \times \bar{v}^n \left(\frac{d_o-d_w}{d_o+d_w}\right)^{n+1}
\]

\[
= \frac{2^n \times 3^n \times k_{ann} \times q^n}{\pi \left(\frac{d_o-d_w}{d_o+d_w}\right)^{2n+1} \left(\frac{d_o+d_w}{d_o-d_w}\right)}, \tag{4-107}
\]

with

\[
k_{ann} = \left(\frac{2n+1}{3n}\right)^n k. \tag{4-108}
\]

For Bingham plastic fluids, the main flow equation is

\[
\xi = \frac{12\bar{v}}{d_o-d_w} \times \frac{\mu_p}{\tau_y} = \frac{48q}{\pi \left(\frac{d_o-d_w}{d_o+d_w}\right)^2 \left(\frac{d_o+d_w}{d_o-d_w}\right)} \times \frac{\mu_p}{\tau_y}
\]

\[
= \frac{1}{\psi} \left(1 - \frac{3}{2} \psi + \frac{1}{2} \psi^3\right), \tag{4-109}
\]

where

\[
\psi = \frac{\tau_y}{\tau_w} = \frac{\tau_y}{4 \left(\frac{dp}{dz}_f\right)_f}. \tag{4-110}
\]

A solution to Eq. 4-109 is given by (Whittaker, 1985)

\[
\psi = 2 \sqrt{\frac{2\xi}{3} + 1} \times \sin \left[\frac{1}{3} \arcsin \left(\frac{2\xi}{3} + 1\right)^{-\frac{3}{2}}\right]. \tag{4-111}
\]

Again, when the dimensionless shear rate, \( \xi \), is sufficiently large compared to the yield stress/plastic viscosity ratio, the term to the third power in Eq. 4-109 can be neglected. This leads to the following approximations.

\[
\psi = \frac{1}{\xi + \frac{3}{2}} \tag{4-112}
\]

\[
\frac{dp}{dz}_f = \frac{6\tau_y}{d_o-d_w} + \frac{48\mu_p \bar{v}}{(d_o-d_w)^2 \left(\frac{d_o+d_w}{d_o-d_w}\right)^{n+1}}
\]

\[
= \frac{6\tau_y}{d_o-d_w} + \frac{192\mu_p q}{\pi \left(\frac{d_o-d_w}{d_o+d_w}\right)^3 \left(\frac{d_o+d_w}{d_o-d_w}\right)}, \tag{4-113}
\]

For example, if \( \frac{12\bar{v}}{d_o-d_w} \times \frac{\mu_p}{\tau_y} > 2.23 \), calculating the friction pressures from Eq. 4-113 will overestimate them by less than 1%.

Examples of velocity profiles and shear-rate profiles for the power-law and Bingham plastic models are presented in Figs. 4-41 and 4-42.

For Herschel-Bulkley fluids, the flow equation needs to be solved numerically. Again, one relates a dimensionless shear rate, \( \xi \), to a reciprocal dimensionless shear stress:

\[
\frac{12\bar{v}}{d_o-d_w} \times \frac{\mu_p}{\tau_y} = \frac{3n (1-\psi)^{1+1}}{n (1+n+n\psi)} \left(\frac{k}{\tau_y}\right)^{1/n}. \tag{4-114}
\]

An approximation of Eq. 4-114 can be used for large values of \( \xi \), or when \( \psi \) is sufficiently small, and it leads to the following explicit expression:

\[
\frac{dp}{dz}_f = \frac{6\tau_y}{d_o-d_w} + \left(\frac{2n+1}{n}\right)^{n+1} \left(\frac{2(n+1)k}{(d_o-d_w)^{n+1}}\right)^{n}. \tag{4-115}
\]

Reviews of infinite plane slot flow equations for other model fluids (Casson, Robertson and Stiff) are presented by Whittaker (1985) and Fordham et al. (1991).

\( \overset{\text{For Herschel-Bulkley fluids, } 5/2 \text{ is sometimes referred to as Herschel-Bulkley number for annular flow.}}{\text{§§§§}} \)
**Fig. 4-41.** Normalized velocity- and shear-rate profiles for a power-law fluid flowing in a slot or narrow annulus.

**Fig. 4-42.** Normalized velocity- and shear-rate profiles for a Bingham plastic fluid flowing in a slot or narrow annulus ($\psi$ = reciprocal dimensionless shear stress; $\xi$ = dimensionless shear rate).
4.5.3 Concentric annular flow

For flow in concentric annuli with a large radius ratio, there is no general expression for the velocity profile and the volume flux. The equations relating friction pressures to flow rate will first be described. The effect of the radius ratio on velocity profiles will be briefly discussed.

For Newtonian fluids, the principal equation is

\[
\left( \frac{dp}{dz} \right)_f = \frac{32 \mu \bar{v}}{d_o^2} \left[ \frac{1}{(1 + \alpha^2) + \frac{(1 - \alpha^2)^2}{\ln(\alpha)}} \right]
\]

where \( \alpha \) is the ratio of the inner diameter to the outer diameter \( (d_w/d_o) \).

Fredrickson and Bird (1958) first developed the flow equations for power-law and Bingham plastic fluids. An improved formula for power-law fluids has since been developed by Hanks and Larsen (1979). The same year, Hanks (1979) presented the flow equation for Herschel-Bulkley fluids.

For power-law fluids, the flow is described by

\[
\left( \frac{dp}{dz} \right)_f = \frac{128 \mu q}{\pi (d_o)^4} \left[ \frac{1}{(1 - \lambda^4) + \frac{(1 - \alpha^4 - \alpha^2)^2}{\ln(\alpha)}} \right],
\]

where \( \lambda \) is the normalized distance from the pipe axis where the shear stress is 0, or where the velocity reaches its maximum. Its value is given by the solution of

\[
\int_\alpha^\lambda \left( \frac{\lambda^2 - x}{x} \right)^{\frac{1}{n}} dx - \int_1^\lambda \left( \frac{\lambda^2 - x}{x} \right)^{\frac{1}{n}} dx = 0.
\]

\( \lambda \) depends only on the radius or diameter ratio, \( \alpha \), and the power-law index of the fluid. Hanks and Larsen (1979) published tabulated values for \( \lambda \) for a series of \( \alpha \) and \( n \) values. Later, an approximation to the above equations was developed by Whittaker et al. (1985).

\[
\left( \frac{dp}{dz} \right)_f = \frac{2^{3n+2} k(\bar{v})^n}{[d_o(1 - \alpha)]^{n+1}} G^n
\]

\[
= \frac{2^{3n+2} k q^n}{\pi^n (d_o)^{3n+1} (1 - \alpha)^{2n+1} (1 + \alpha)} G^n,
\]

which is the pipe-flow equation with a correction factor that depends on the power-law index and the annulus diameter ratio.

\[
G = \left( 1 + \frac{S}{2} \left[ (3 - S)(n + 1) \right] \right)
\]

\[
S = 1 - \left( 1 - \alpha^V \right)^{1/Y}
\]

\[
Y = 0.37 \times n^{-0.14}
\]

For Bingham plastic fluids, the relevant equations are given below.

\[
\frac{32q}{\pi (d_o)^3} \frac{\mu_p}{\tau_y} = \frac{1}{\beta} \times \left[ \left( 1 - \alpha^4 \right) - 2\lambda(\lambda - \beta)(1 - \alpha^2) \right] \times \left[ \frac{4}{3} (1 + \alpha^3) \beta + \frac{1}{3} (2\lambda - \beta)^3 \beta \right],
\]

where

\[
\beta = \frac{4 \tau_y}{d_o}.
\]

Here, \( \lambda \) is the largest normalized distance from the pipe axis where the shear stress of the fluid becomes equal to the yield stress. Its value is defined by the following implicit equation.

\[
\left[ 2\lambda(\lambda - \beta) \ln \left( \frac{\lambda - \beta}{\alpha \lambda} \right) \right] - \left[ 1 + (\alpha + \beta)^2 \right] + \left[ 2(1 - \lambda) \beta \right] = 0
\]

For these last two rheological models, the flow equations are implicit, and they can only be solved numerically. This is also the case for Herschel-Bulkley fluids, for which flow equations are described and solved by Hanks (1979). Notably, Fordham et al. (1991) presented a general method for the practical calculation of laminar flow in centered annuli of arbitrary radius that is very useful.
Because the narrow-gap equations are much simpler to solve, the question that must be addressed is: “What are the errors associated with this approximation when compared to the exact solution?” The answer really depends on the application. For determining the flow rate corresponding to a given friction pressure, this approximation remains reasonable for diameter ratios larger than about 0.5, but, as shown in Fig. 4-43, it deteriorates quickly for small-diameter ratios. The lower the power index is (i.e., the less Newtonian the fluid behavior), the larger the error will be. Similar errors are obtained with Bingham plastic and Herschel-Bulkley fluids.

On the other hand, when trying to do the reverse calculation (i.e., determine the friction pressure corresponding to a given flow rate), even for an annulus diameter ratio as low as 0.3, the corresponding error is lower than 2.5%, both for power-law and Bingham plastic fluids. This is likely to be true for any generalized non-Newtonian model, provided that the fluid is shear thinning.

Velocity profiles are affected by the annular radius ratio. As this ratio decreases, the shear rate at the wall of the inner cylinder increases faster than that at the outer cylinder. Also, the point of maximum velocity (or the position of the plug zone) is shifted towards the inner cylinder, and the maximum velocity itself is modified. This is illustrated by the following equations, which are given only for Newtonian fluids.

\[
\nu(r) = \frac{1}{2} \left[ \left( \frac{r}{r_0} \right)^2 - \left( \frac{1 - \alpha^2}{\ln(\alpha)} \right) \ln \left( \frac{r}{r_0} \right) \right] \left( 1 + \frac{1 - \alpha^2}{\ln(\alpha)} \right)
\]

(4-124)

\[
\gamma \left( r_o \right) = 2 \frac{\nu}{r_0} \left[ \frac{\alpha^2}{\ln(\alpha)} + \frac{1 - \alpha^2}{\ln(\alpha)} \right]
\]

(4-125)

and

\[
\gamma \left( r_w \right) = 2 \frac{\nu}{r_w} \left[ \frac{\alpha^2}{\ln(\alpha)} + \frac{1 - \alpha^2}{\ln(\alpha)} \right]
\]

(4-126)

where \( r \) now represents the distance to the axis of symmetry of the two cylinders. The distortion of the velocity profile compared to a narrow gap approximation is illustrated in Fig. 4-44. The same trend is observed for non-Newtonian fluids. Again, unless the radius ratio is very small and the fluid is highly non-Newtonian, the distortion of the velocity profile is not very significant.
Therefore, it is reasonable to conclude that the narrow-gap approximation is often a good engineering approximation to determine laminar friction pressures of spacers and cement slurries in annuli because

- in most circumstances, annuli are relatively narrow during cementing operations
- for the diameter ratio in question, this approximation provides an upper limit for the friction pressures
- in practice, friction pressures are often negligible for large-diameter ratios.

4.5.4 Circulation efficiency

Some of the flow equations described above can be used to determine the process efficiency while circulating a fluid in a pipe or an annulus. Consider a section of pipe or annular section of length \( z \). The circulation efficiency after a circulation time \( t \) is defined as 1 minus the ratio of two volumes. The first is the volume of the pipe or annular section that still contains the original fluid before starting circulation (i.e., the red-colored fluid in Fig. 4-45). The second is the volume of the entire pipe or annular section.

We will first examine circulation efficiency in a pipe and then in a concentric annulus. To simplify the equations, it is useful to introduce a few dimensionless parameters. The dimensionless time, \( t^* \), is the number of pipe-section volumes pumped at time \( t \). It is given by

\[
 t^* = \frac{vt}{z}. 
\]  

The dimensionless breakthrough time, \( t^*_{\text{break}} \), is defined by

\[
 t^*_{\text{break}} = \frac{vt}{v_{\text{max}} z} = \frac{vt^*}{v_{\text{max}}}, 
\]  

where \( v_{\text{max}} \) is the maximum velocity of the fluid particles (i.e., the velocity at the pipe axis). It is simply the dimensionless time at which fluid particles that entered the pipe first at \( t = 0 \) exit the pipe section.

The breakthrough radius, \( r^*_{\text{break}} \), can be calculated from

\[
 r^*_{\text{break}} = \frac{z}{t} = \frac{v}{t^*_{\text{break}}}. 
\]

Fig. 4-45. Schematic of the circulation-efficiency concept.
For a narrow annulus, the equation that is equivalent to the previous one is

\[ \eta_{circ}(t^*) = 2 \left[ \frac{t_{break}}{r_o - r_w} + t^* \right] \int_{r_{break}}^{r_o} \frac{v(r)}{\bar{v}} \, dr \]

with \( r \) now being the distance from the plane of symmetry of the narrow annulus. Similar equations can be developed for large annuli, but the calculations are more complex because the velocity profile is no longer symmetrical.

The equations giving the dimensionless breakthrough time and the circulation efficiency for flow in pipes and in narrow annuli are presented in Appendix A. Most of the conclusions drawn about velocity profiles can be applied to circulation efficiency.

- For power-law fluids, circulation efficiency depends only on the power-law index. The smaller the power-law index, the larger the dimensionless breakthrough time and the more efficient the circulation process.
- For Bingham plastic fluids, circulation efficiency depends on the dimensionless shear rate. The smaller the dimensionless shear rate, the larger the dimensionless breakthrough time and the more efficient the circulation process.
- For Herschel-Bulkley fluids, circulation efficiency depends on both the power-law index and the dimensionless shear rate. The smaller these two parameters are, the larger the dimensionless breakthrough time and the more efficient the circulation process.

These points are discussed in more detail in Chapter 5.

### 4-6 Friction pressure calculations for all flow regimes

#### 4-6.1 Pipe flow

Regardless of the type of fluid, once a critical flow rate in a given pipe is exceeded, streamlines are no longer parallel to the main direction of flow. Fluid particles become subject to random velocity fluctuations in both amplitude and direction. In fact, velocity fluctuations are not completely random. Near the wall, fluctuations in the axial direction are greater than in the radial direction, and both approach 0 at the wall. Such flow instability starts at a given value of a dimensionless parameter, the Reynolds number \( (N_{Re}) \), which, for Newtonian fluids, is defined by

\[ N_{Re} = \frac{\rho \bar{v} d}{\mu} . \]  

(4-133)

Departure from laminar flow occurs as the Reynolds number increases beyond a value of 2,100. A transition regime that is not very well characterized exists until \( N_{Re} = 3,000 \). Above this value, flow becomes turbulent. The resistance to flow at the pipe wall can then be expressed as

\[ \frac{1}{\sqrt{f_{fr}}} = H \times \log \left( N_{Re} \sqrt{f_{fr}} \right) + J, \]  

(4-134)

where \( f_{fr} \), the Fanning friction factor, is defined by

\[ f_{fr} = \frac{2 \tau_W}{\rho (\bar{v})^2}. \]  

(4-135)

In Eq. 4-134, which was first proposed by Von Karman in 1930 (Schlichting, 1979), parameters \( H \) and \( J \) depend on the roughness of the pipe. For turbulent flow in smooth pipes, \( H = 4.0 \) and \( J = -0.4 \). With these definitions it should be noticed that, in laminar flow

\[ f_{fr} = \frac{16}{N_{Re}}. \]  

(4-136)

In the transition regime, the friction-factor/Reynolds number relationship is not uniquely defined. However, for most engineering applications, a linear interpolation is performed on a log-log scale between the laminar values of \( f_{fr} \) at a Reynolds numbers of 2,100 and its turbulent value at a Reynolds number of 3,000 (Fig. 4-46).
Similar equations have been developed for purely viscous non-Newtonian fluids. The main problem is to determine which viscosity value should be used in the expression for the Reynolds number, because viscosity is shear-rate dependent. For power-law fluids, Metzner and Reed (1955) proposed a Reynolds number definition such that Eq. 4-136 still holds true. This leads to

\[
\left(N_{\text{Re}}\right)_{MR} = \frac{\rho (\bar{v})^{2-n} (d_\text{w})^n}{8^{n-1} k_{\text{pipe}}} \quad (4-137)
\]

where \(k_{\text{pipe}}\) is the pipe consistency index previously defined in Eq. 4-90. Using a dimensional analysis, Dodge and Metzner (1959) found that turbulent flow of power-law fluids in smooth pipes could be described by a relationship similar to Eq. 4-134:

\[
\frac{1}{\sqrt{f_{fr}}} = H_n \times \log \left( \left(N_{\text{Re}}\right)_{MR} \times (f_{fr})^{-\frac{n}{2}} \right) + J_n \quad (4-138)
\]

where \(H_n\) and \(J_n\) are a function of the power-law index \(n\).

For Bingham plastic fluids, the simplest method (Hedström, 1952) is to assume that, once turbulent flow is reached, the fluid is Newtonian, with a viscosity equal to its plastic viscosity. This indicates that the relevant Reynolds number in turbulent flow, often referred to as the Bingham-Reynolds number, is

\[
\left(N_{\text{Re}}\right)_{BG} = \frac{\rho \bar{v} d_\text{w}}{\mu_p}. \quad (4-139)
\]

Equation 4-134 is then used to calculate friction pressures for a given flow rate (Fig. 4-46). This assumption has been established empirically for smooth pipes by several authors working with different types of fluids (Govier and Aziz, 1977). Unfortunately, it does not seem to hold for all cement slurries. Guillot and Denis (1988) showed that this procedure can lead to a considerable overestimation of friction factors (Fig. 4-47).

Other methods for calculating turbulent friction pressures of Bingham plastic and Herschel-Bulkley fluids in pipes have been developed (Govier and Aziz, 1977), but their validity has not been fully established for cement slurries or they are limited to a specific rheological model. A more general approach that does not suffer from this limitation was proposed by Dodge and Metzner (1959). They generalized Eq. 4-138 to describe the turbulent flow of nonelastic non-Newtonian fluids in smooth pipes (Fig. 4-46).

\[
\frac{1}{\sqrt{f_{fr}}} = H_w \times \log \left( \left(N_{\text{Re}}\right)_{MR} \times (f_{fr})^{-\frac{n'}{2}} \right) + J_w \quad (4-140)
\]

where \(H_w\) and \(J_w\) are function of \(n'\) only. The generalized Reynolds number, \(\left(N_{\text{Re}}\right)_{MR}\), is defined by Metzner and Reed (1955) as

\[
\left(N_{\text{Re}}\right)_{MR} = \frac{\rho (\bar{v})^{2-n'} (d_\text{w})^{n'}}{8^{n'-1} k'_{\text{pipe}}} \quad (4-141)
\]

The local power-law parameters, \(n'\) and \(k'_{\text{pipe}}\), are defined by

\[
n' = \frac{d \log (\tau_w)}{d \log \left( \frac{8 \bar{f}_{\text{lam}}}{d_\text{w}} \right)} \quad (4-142)
\]

and

\[
k'_{\text{pipe}} = \frac{\tau_w}{\left( \frac{8 \bar{f}_{\text{lam}}}{d_\text{w}} \right)^{n'}} \quad (4-143)
\]
\( \bar{v}_{\text{lam}} \) is the average velocity for the same shear stress at the wall, \( \tau_w \), assuming the flow regime is laminar. Notice that, for power-law fluids,

\[
n' = n \quad (4-144)
\]

and

\[
k'_{\text{pipe}} = k_{\text{pipe}} = \left( \frac{3n+1}{4n} \right)^n k. \quad (4-145)
\]

Extending the application of Eq. 4-136, and using the generalized equations for power-law fluids defined by Metzner and Reed (Eqs. 4-141 to 4-143), is straightforward. However, for Eq. 4-140, the extension has been questioned by Hanks (1986) as not being theoretically correct. Dodge and Metzner (1959) justified this generalization by pointing out that, in turbulent flow, only the shear in very close proximity to the wall contributes significantly to the friction. Dodge and Metzner (1959) gave experimental evidence that this is correct. For the non-Newtonian fluids they tested, with \( n' \) values from 0.36 to 1.0, and \( (N_{Re})_{MR} \) values from 2,900 to 35,000, they empirically found that, for smooth pipes:

\[
H_{n'} = \frac{4.0}{(n')^{0.75}} \quad \text{and} \quad J_{n'} = -\frac{0.4}{(n')^{1.2}}. \quad (4-146)
\]

Dodge and Metzner (1959) found that their method gave remarkable friction-pressure predictions for the fluids they tested (Fig. 4-48). Very good results were also obtained by Guillot and Denis (1988) with cement slurries whose rheological properties were described by a three-parameter model (Fig. 4-49).

Notice that, even for power-law fluids, Eqs. 4-138 and 4-140 are implicit with regard to the friction factor. For most engineering applications, it can be replaced by an explicit expression such as that given in Appendix A (Tables A-4 and A-5). The same equation can also be modified to account for pipe-wall roughness (Reed and Pilehvari, 1993):

\[
\frac{1}{\sqrt{f_{fr}}} = 4.0 \times \log \left\{ \frac{0.27H}{d_w} + \frac{1.259}{(N_{Re})_{MR} \times \left( f_{fr} \right)^{1 - \left( \frac{n}{2} \right)} \left( n' \right)^{0.65}} \right\}, \quad (4-147)
\]

where \( H \) is the mean height of protuberances at the pipe wall.

### End of laminar flow regime

Now that the friction factor/Reynolds number relationships are defined in laminar flow and turbulent flow, the situation in the transition regime needs to be addressed. There are numerous empirical or semiempirical models to predict the Reynolds number, \( N_{Re1} \), at which the laminar flow regime of purely viscous non-Newtonian fluids no longer applies. The criteria are either global (Mishra and Tripathi, 1971) or local (Ryan and Johnson, 1959; Hanks, 1963a and 1969). These semiempirical criteria are defined in such a way that they correspond to a
Reynolds number value of 2,100 for a Newtonian fluid. For power-law fluids, \( N_{Re1} \) increases as \( n \) decreases.

Despite the differences between the theories, the discrepancies in critical flow rates or velocities are usually reasonable down to \( n = 0.3 \), as shown in Fig. 4-50. This is because the Reynolds number is proportional to the flow rate to the power \((2 - n)\). For some spacer fluids, the Mishra and Tripathi (1971) criterion seems to give a reasonable prediction of the laminar flow stability (Brand et al., 2001). If a good experimental dataset does not exist, the author proposes Eq. 4-148. This is reasonable because fluids with a power-law index of less than 0.3 are rarely found at shear rates where laminar flow ends.

\[
N_{Re1} = 3,250 - 1,150n \tag{4-148}
\]

For Bingham plastic fluids, the theory proposed by Hanks (1967) is the most popular. The upper limit for the laminar flow regime is often expressed as a relationship between a critical value of the reciprocal dimensionless shear stress \( (\psi_1) \) and the Hedström number \( (N_{He}) \).

\[
N_{He} = \frac{\rho(d_w)^2 \tau_g}{(\mu_p)^2} \tag{4-149}
\]

After the Hanks theory,

\[
\frac{\psi_1}{(1 - \psi_1)^3} = \frac{N_{He}}{16,800}. \tag{4-150}
\]

The critical value of the reciprocal dimensionless shear stress is then inserted into expressions giving the Bingham plastic Reynolds number or the Metzner and Reed Reynolds number as a function of the Hedström number and of the reciprocal dimensionless shear stress. Figure 4-51 gives the critical value of the Bingham plastic Reynolds number for different models. Again, differences between the different theories are not significant up to Hedström numbers on the order of \( 5 \times 10^4 \). Above these values, it is relatively difficult to place Bingham plastic fluids in turbulent flow in a wellbore.

Most of the theoretical models predicting the end of the laminar flow regime are not specific to a given rheological model. They can be used to predict the critical flow rates at which Herschel-Bulkley fluids significantly depart from laminar flow.

Because of the relatively small differences between the different theories, the author has chosen to use Eq. 4-148, where the Reynolds number is the Metzner and Reed Reynolds number \( (N_{Re})_{MR} \) (Eq. 4-141), and \( n \) is replaced by the local power-law index. This way, the same equation can be applied regardless of the rheological model used to describe the behavior of the fluid.

\[
N_{Re2} = 4,150 - 1,150n \tag{4-151}
\]

One of the limitations of Eq. 4-151 is that it is not compatible with the Fanning friction factor/Reynolds number relationship when the local power index is too low (typically lower than 0.3). The reason is that, at \( N_{Re2} \), the turbulent friction factor given by Eq. 4-138 or 4-140 would be lower than the laminar one. This is not physically sound. This difficulty can easily be avoided by basing...
the definition of \( N_{Re2} \) on the Reynolds number value at the intersection of the Fanning friction factor/Reynolds number curves in laminar and turbulent flow.

Other constraints are imposed by the local power-law approach with some rheological models (e.g., Bingham plastic) because the calculated friction pressures may not be a monotonic function of the flow rate at low power-law index values (typically lower than 0.3). When such cases are encountered, the values of \( N_{Re2} (n') \) should be higher than those calculated from Eq. 4-151.

For the Fanning friction factor in the transitional regime (e.g., for Newtonian fluids), a linear interpolation is made on a log-log scale between the laminar value of the friction factor at \( N_{Re1} \) and its value at \( N_{Re2} \).

**Example of application to a power-law fluid**

A power-law fluid with a density of 1,300 kg/m³, a power-law index of 0.5, and a consistency index of 1.0 Pa·sⁿ is flowing in a tube with an inner diameter of 127 mm. Determine the friction pressure gradient for a series of three different flow rates: 0.01, 0.03, and 0.024 m³/s.

The first step in the calculation is to determine the flow regime. One must calculate the mean velocity of the fluid and its Reynolds number using Eq. 4-137.

<table>
<thead>
<tr>
<th>Flow rate (m³/s)</th>
<th>0.01</th>
<th>0.03</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mean velocity (m/s)</td>
<td>0.789</td>
<td>2.37</td>
</tr>
<tr>
<td>Reynolds number, ((N_{Re})_{MR})</td>
<td>822</td>
<td>4,271</td>
</tr>
</tbody>
</table>

The Reynolds number values are then compared to the critical values given by Eqs. 4-148 and 4-151 (i.e., 2,675 and 3,575). Therefore, at the lowest flow rate, the flow regime is laminar. At the highest flow rate it is turbulent. One can now calculate the Fanning friction factor for the appropriate flow regime (i.e., Eq. 4-136 for laminar flow and Eqs. 4-138 and 4-146 [or Eq. 4-147, in which we will assume that \( h = 0 \)] for turbulent flow). Once the friction factor is known, the shear stress at the wall is derived from Eq. 4-135 and the friction pressure gradient from Eq. 4-14. This yields the following results.

<table>
<thead>
<tr>
<th>Flow rate (m³/s)</th>
<th>0.01</th>
<th>0.03</th>
</tr>
</thead>
<tbody>
<tr>
<td>Friction factor</td>
<td>0.0195</td>
<td>0.00645</td>
</tr>
<tr>
<td>Wall shear stress (Pa)</td>
<td>7.88</td>
<td>23.5</td>
</tr>
<tr>
<td>Friction pressure gradient (Pa/m)</td>
<td>248</td>
<td>740</td>
</tr>
</tbody>
</table>

For a flow rate of 0.024 m³/s, the Reynolds number is equal to 3,056 and the flow regime is transitional. Therefore, one must determine the friction factor at \( N_{Re1} \) (using Eq. 4-136) and at \( N_{Re2} \) (using Eqs. 4-138 and 4-146). Then a linear interpolation is made on a log-log scale between these two values to determine the value of the Fanning friction factor at the calculated Reynolds number. The wall shear stress and the friction pressure gradient are determined as above, which gives the following.

<table>
<thead>
<tr>
<th>Flow rate (m³/s)</th>
<th>0.024</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fanning friction factor at ( N_{Re1} )</td>
<td>0.00598</td>
</tr>
<tr>
<td>Fanning friction factor at ( N_{Re2} )</td>
<td>0.0686</td>
</tr>
<tr>
<td>Fanning friction factor</td>
<td>0.0637</td>
</tr>
<tr>
<td>Wall shear stress (Pa)</td>
<td>14.9</td>
</tr>
<tr>
<td>Friction pressure gradient (Pa/m)</td>
<td>468</td>
</tr>
</tbody>
</table>

Instead of performing the calculations, one can use charts such as that presented in Fig. 4-46; however, the results are not likely to be as accurate.

**Example of application to nonpower-law fluids**

Application of the Dodge and Metzner method to non-power-law fluids is not straightforward, because it leads to a system of implicit equations that must be solved numerically (see Appendix A in which equations are developed for Bingham plastic fluids). Results can be presented in the form of master curves for specific rheological models. Figure 4-52 shows the relationship between the friction factor and the Bingham plastic Reynolds number for a series of Hedström number values (Eq. 4-149).

![Fig. 4-52. Fanning friction factor/Bingham Reynolds number relationship as a function of the Hedström number for pipe flow.](image)

Figure 4-53 shows the same graph for a Herschel-Bulkley fluid, where the Reynolds number is now defined as

\[
(N_{Re})_{HB} = \frac{\rho \left( \frac{n}{w} \right)^{2-n} \left( D_w \right)^{n}}{8^{n-1} \times \left( 3n + 1 \right)^{n}} \times k,
\]  
(4-152)
and the generalized Hedström number is

\[(N_{H_{e}})_{HB} = \frac{\rho(d)_w^2}{\tau_g}(\frac{\tau_g}{k})^{\frac{2}{n}} \]  

(4-153)

for a specific value of the power-law index (e.g., 0.5).

As with power-law fluids, it is possible to determine the flow regime and the Fanning friction factor by entering the pipe diameter, fluid density, rheological properties and the flow rate or velocity. One uses Eqs. 4-139 and 4-149, or 4-152 and 4-153, plus Figs. 4-52 or 4-53 (for \(n = 0.5\)). Once the friction factor is known, the corresponding wall stress friction-pressure gradient can be determined as described above for the power-law fluid.

### 4-6.2 Concentric annular flow

The concentric annular flow discussion will be limited to the case of narrow annuli. The same local power-law approach described above can be used, with the friction factor being defined by Eq. 4-135 and the Reynolds number by

\[(N_{Re})_{AN} = \frac{\rho(d)_w^2}{\tau_g}(\frac{\tau_g}{k})^{\frac{2}{n}} \]  

(4-154)

\[n' = \frac{d\log(\tau_0)}{d\log(\frac{12\tau_{lam}}{(d)_o^2 - (d)_w^2})} \]  

(4-155)

and

\[k'_ann = \frac{\tau_w}{\frac{12\tau_{lam}}{(d)_o - (d)_w}} \]  

(4-156)

Note that using the hydraulic diameter, \(d_o - d_w\), as the characteristic length in the Reynolds number is arbitrary. In laminar flow these definitions lead to

\[f_{fr} = \frac{24}{(N_{Re})_{AN}} \]  

(4-157)

In turbulent flow, the friction factor is slightly higher than what Eq. 4-138 or 4-140 would give. These equations can be replaced by

\[\frac{1}{\sqrt{f_{fr}}} = H_{n'} \times \log\left[\frac{2}{3}(N_{Re})_{AN} \times (f_{fr})^{1-\left(\frac{n}{2}\right)}\right] + J_{n'} \]  

(4-158)

where \(H_{n'}\) and \(J_{n'}\) are defined by Eq. 4-146.

For the transition zone, common industry practice is to use the same criteria as those for pipe flow. This is the option taken in this chapter and in Appendix A. In fact, there is experimental evidence (Patel and Head, 1969) and theoretical reasons (Hanks, 1963a) to believe that this practice leads to an underestimation of the critical Reynolds number. For Newtonian fluids flowing between parallel plates, Patel and Head (1969) observed a deviation from laminar flow for Reynolds number values around 2,700 (as defined by Eq. 4-154), while Hanks (1963a) predicted a theoretical value of 2,800.

Several theories exist for purely viscous non-Newtonian fluids, including some that take into account the effect of the annular radius ratio. Comparison of these theories leads to discrepancies similar to those described for a pipe-flow geometry in the previous section.

**Example of application to a power-law fluid**

A power-law fluid with a density of 1,300 kg/m³, a power-law index of 0.5, and a consistency index of 0.4 Pa·s is flowing in an annulus of 215.9 × 177.8 mm. Determine the friction pressure gradient for a series of three different flow rates: 0.008 m³/s, 0.02 m³/s, and 0.016 m³/s.

<table>
<thead>
<tr>
<th>Flow rate (m³/s)</th>
<th>Mean velocity (m/s)</th>
<th>Reynolds number</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.008</td>
<td>0.679</td>
<td>1,065</td>
</tr>
<tr>
<td>0.02</td>
<td>1.77</td>
<td>4,210</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Flow rate (m³/s)</th>
<th>Mean velocity (m/s)</th>
<th>Reynolds number</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.016</td>
<td>0.02</td>
<td>2,800</td>
</tr>
</tbody>
</table>

Because the Reynolds number is multiplied by \(\frac{1}{n}\) in the turbulent flow equation, it would be tempting to use \((N_{Re})_{AN}/n\) as the definition of the Reynolds number. Equations 4–136, 4–138, and 4–146 (i.e., the pipe-flow equations) could then be used to describe laminar and turbulent flow in a narrow concentric annulus. But this simple analogy does not work in the transition regime.
The Reynolds numbers are then compared to the critical values given by Eqs. 4-148 and 4-151 (i.e., 2,675 and 3,575). At the lowest flow rate, the flow regime is laminar. At the highest flow rate, it is turbulent. One can now calculate the friction factor for the appropriate flow regime (i.e., Eq. 4-157 for laminar flow and Eqs. 4-158 and 4-146 for turbulent flow). Once the friction factor is known, the shear stress at the wall is derived from Eq. 4-135 and the friction pressure gradient from Eq. 4-17. This gives the following.

| Flow rate (m³/s) | 0.008 | 0.02 |
| Friction factor | 0.0225 | 0.00749 |
| Wall shear stress (Pa) | 6.75 | 14.0 |
| Friction pressure gradient (Pa/m) | 709 | 1,473 |

For a flow rate of 0.016 m³/s, the Reynolds number is equal to 3,012, and the flow regime is transitional. One must therefore determine the friction factor at \( N_{Re1} \) using Eq. 4-157 and at \( N_{Re2} \) using Eqs. 4-158 and 4-146. Then a linear interpolation is made on a log-log scale between these two values to determine the value of the friction factor at the calculated Reynolds number. The wall shear stress and the friction pressure gradient are determined as above, giving the following.

| Flow rate (m³/s) | 0.016 |
| Friction factor at \( N_{Re1} \) | 0.00897 |
| Friction factor at \( N_{Re2} \) | 0.0796 |
| Friction factor | 0.0854 |
| Wall shear stress (Pa) | 10.2 |
| Friction pressure gradient (Pa/m) | 1,075 |

An alternative to these calculations is to use charts like those presented in Fig. 4-46 for pipe flow. Of course, the results are not likely to be as accurate.

**Example of application to nonpower-law fluids**

As stated earlier for pipe flow, the application of the local-power-law method to nonpower-law fluids is not straightforward. To make the results more useful, they can be presented in the form of master curves for specific rheological models. Figure 4-54 shows the relationship between the friction factor and the Bingham plastic Reynolds number for a series of Hedström-number values where these dimensionless numbers are defined as

\[
(N_{Re})_{BG} = \frac{\rho \bar{v} (d_o - d_w)}{\mu p}.
\]  

and

\[
N_{Re} = \frac{\rho (d_o - d_w)^2 \tau_y}{(\mu p)^2}.
\]  

Figure 4-55 shows a similar graph for a Herschel-Bulkley fluid in which the Reynolds number is now defined as

\[
(N_{Re})_{HB} = \frac{\rho (d_o - d_w)^2 \tau_y}{12^{n-1} \left( \frac{2n+1}{3n} \right)^n \times k}.
\]  

and the generalized Hedström number as

\[
(N_{Re})_{HB} = \frac{\rho (d_o - d_w)^2 (\frac{\tau_y}{k})^2}{\tau_y}.
\]  

for a power-law index of 0.5.
As with power-law fluids, it is now possible to determine the flow regime and the friction factor using Eqs. 4-159 and 4-160, or 4-161 and 4-162 (for the specific case of \( n = 0.5 \)). One knows the annular diameters, the fluid density, and the fluid’s rheological properties. Once the friction factor is known, the corresponding wall shear stress and friction pressure can be determined as described above for a power-law fluid.

### 4-6.3 Effect of pipe eccentricity

The previous discussion assumed that flow occurred in a perfectly centered annulus. Of course, this is not realistic because gravity pushes the pipe downward. The resulting effect on fluid flow is significant. Consider a cross section of an eccentric annulus, shown in Fig. 4-56. The eccentricity, \( \varepsilon \), is defined as the ratio of the distance between the centers of the cylinders to their radial difference. The well completion industry also uses the pipe standoff ratio, defined in Specification for Bow-Spring Casing Centralizers (API Spec 10D, 2002) as

\[
R_{STO} = \left[ (1 - \varepsilon) \times 100 \right].
\]  

Pipe eccentricity plays a predominant role in the mud-circulation and mud-displacement processes (Chapter 5). When the flow regime is laminar, the effects of eccentricity on the flow of wellbore fluids in annuli can be considered using numerical models and software that quickly provide accurate answers. This section will describe these effects, starting from the laminar flow regime with Newtonian and non-Newtonian fluids, and then attempting to extend the analysis to nonlaminar flows.

Flow in eccentric annuli has been the subject of many experimental, theoretical, and modeling studies. Early publications on Newtonian fluids clearly identified that pipe eccentricity in laminar flow leads to the following effects.

- The velocity profile is distorted. The fluid flows faster on the wide side of the annulus than on its narrow side (Fig. 4-57).

![Fig. 4-56. Profile of the slot equivalent of an eccentric annulus (from Iyoho and Azar, 1981). Reprinted with permission of SPE.](image)

![Fig. 4-57. Typical example of velocity profile on the narrow and wide sides of eccentric annuli for model fluids. Reprinted with permission of SPE.](image)

When an annulus is concentric, its eccentricity is 0 and the pipe standoff ratio is 100%. Conversely, when the inner cylinder is touching the wall of the outer cylinder, the eccentricity is 1 while the pipe standoff ratio, \( R_{STO} \), is 0%.
As eccentricity increases, friction pressure decreases (Fig. 4-58).

The laminar flow regime ends earlier as eccentricity increases (based on a bulk Reynolds number).

The effects of pipe eccentricity on the laminar flow of non-Newtonian fluids are similar to those observed with Newtonian fluids; however, they are more difficult to predict for fluids exhibiting a yield stress. Complete analytical and numerical solutions were presented for the flow of a Bingham plastic fluid in a narrow eccentric annulus (Walton and Bittleston, 1991). For Herschel-Bulkley fluids, most authors developed numerical solutions based on a finite difference method. Figure 4-59 shows examples of velocity profiles of a Herschel-Bulkley fluid flowing in annuli of different eccentricities. It illustrates that, for fluids exhibiting a yield stress, the distortion of the velocity profile can be so severe that the fluid is static on the narrow side of the annulus. This is because the shear stress in the fluid is lower than the fluid yield stress.

A general conclusion can be drawn concerning velocity profiles. For equivalent flow geometries, distortion of the velocity profile increases as a fluid becomes more shear thinning. This leads to an interesting consequence. The reader will recall that shear thinning fluids have better circulation efficiency than Newtonian fluids in a concentric annulus. The reverse is true for an eccentric annulus. This effect is discussed in Chapter 5.

The numerical models described above are used for predicting friction pressures. Every other condition being the same, laminar flow friction pressures decrease as pipe eccentricity increases. The largest reduction—60%—is observed for Newtonian fluids when the pipe is totally eccentered. In the case of power-law fluids, Haciislamoglu and Langlinais (1990) solved the laminar flow equations expressed in a bipolar coordinate system, also using a finite difference method. They were able to propose a simple method to account for eccentricity effects. For power-law indices \( n \) between 0.4 and 1.0, they found that the laminar flow friction pressures in annuli with eccentricities \( \varepsilon \) from 0 to 0.95, standoff \( R_{STD} \) from 5 to 100%, and diameter ratio \( \alpha \) from 0.3 to 0.9 could be determined from concentric-annulus friction pressures using a correction factor, \( B_{fam} \).

![Fig. 4-58. Friction factor × Reynolds number for a Newtonian fluid flowing in an eccentric annulus as a function of the radial ratio and the eccentricity. The product is normalized by its value in a narrow concentric annulus.](image1)

![Fig. 4-59. Velocity profile for a Herschel-Bulkley fluid as a function of eccentricity. Outer diameter = 10 in. [254 mm]. Inner diameter = 5 in. [127 mm]. Flow rate = 200 gal/min [12.6 L/s]. Fluid rheological parameters: \( n = 0.7 \), \( k = 0.00522 \text{ lbft-sec}^n/\text{ft}^2 \) [0.250 Pa-s\(^n\)], \( \tau_y = 0.05 \text{ lbft}^2/\text{ft}^2 \) [2.4 Pa] (from Azouz et al., 1992).](image2)
Reynolds number is even more complex. Extending this analysis to nonlaminar flow regimes is a difficult task, and there is no consensus on the solutions even for Newtonian fluids for the following reasons.

- Velocity-profile distortion and friction-pressure reduction in turbulent flow are less pronounced than in laminar flow.
- As a consequence of the skewed velocity distribution, the transition regime is extended. Compared to a concentric annulus, laminar flow ends earlier, and turbulent flow begins later.

Measurements of turbulent velocity profiles (Nouri et al., 1993) have also highlighted the presence of azimuthal secondary flows. Needless to say, the situation is even less clear for non-Newtonian fluids. Using a simple model, Haciislamoglu and Cartalos (1994) proposed a turbulent flow equation for power-law fluids similar to Eq. 4-161, but that was based on the assumption that \( B_{\text{turb}} \) takes a minimum value of 0.6 for Newtonian fluids.

\[
\frac{dp}{dz}_{f-\text{conc}} = B_{\text{lam}} \times \frac{dp}{dz}_{f-\text{conc}} \quad (4-164)
\]

\[
B_{\text{lam}} = \left( 1 - 0.072 \frac{\varepsilon}{n}^{0.8545} \right) - \left( 1.5 \varepsilon^2 \sqrt{n}^{0.1852} \right) + \left( 0.96 \varepsilon^3 \sqrt{n}^{0.2527} \right) \quad (4-165)
\]

\( B_{\text{lam}} \) takes a minimum value of 0.388 (theoretical minimum is about 0.4) for Newtonian fluids.

Extending this analysis to nonlaminar flow regimes is a difficult task, and there is no consensus on the solutions even for Newtonian fluids for the following reasons.

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\[
B_{\text{turb}} = \left( 1 - 0.048 \frac{\varepsilon}{n}^{0.8545} \right) - \left( 1.5 \varepsilon^2 \sqrt{n}^{0.1852} \right) + \left( 0.285 \varepsilon^3 \sqrt{n}^{0.2527} \right) \quad (4-166)
\]

The transitional regime variation of \( B \) with the Reynolds number is even more complex.

Because of this complexity, many authors use the basic-slot model (McLean et al., 1967; Iyoho and Azar, 1981). In the basic-slot model, the eccentric annular geometry is considered equivalent to a series of independent rectangular slots of varying heights (Fig. 4-56). For a fixed pressure gradient, the contribution of each angular sector to the flow rate is determined using the equations given in Appendix A. The reverse problem of calculating the friction pressure for a given flow rate is then solved numerically. Thus, this model is based on a narrow-annulus approximation for which the annular gap is assumed to slowly vary with azimuthal position; therefore, results will be presented only for high-diameter ratios (i.e., \( d_2/d_1 \leq 0.8 \)).

The basic-slot model is not theoretically correct because it neglects shear in the azimuthal direction. However, this model presents two main advantages.

- It is qualitatively correct (i.e., it clearly shows the principal effects of pipe eccentricity).
- It is quantitatively correct for friction-pressure predictions and to a lesser degree for velocity profiles, provided the fluid is not highly non-Newtonian, the annulus is relatively narrow, and the eccentricity is not too high.

As mentioned earlier, the major effect of eccentricity is to distort the velocity distribution around the annulus. The flow favors the widest part of the annulus (Fig. 4-58). Because both the velocity and the annular gap vary azimuthally around the annulus, some local parameters must be defined. For example, the local Reynolds number for a given annular gap, \( L \), is defined by

\[
N_{Re}(L) = \frac{\rho \bar{v}(L)^{2-n'}(2L)^{n'}}{12^{n-1} k_{\text{ann}}} \quad (4-167)
\]

where \( \bar{v}(L) \) is the mean axial velocity along the local annular gap \( L \).

First, situations are considered in which the fluid is in laminar flow all around the annulus (i.e., all local Reynolds numbers are smaller than the critical Reynolds number \( N_{Re1} \)). For power-law fluids, one can show that the velocity distribution is a function of the annular diameter ratio, the standoff, and the power-law index. Because only narrow annuli are considered, the velocity profiles depend on only two parameters, \( R_{STO} \) and \( n \). To assess the distortion of the velocity distribution caused by eccentricity, it is worthwhile to calculate the ratio of the average velocity along the widest and the narrowest annular gap (\( \bar{v}_{\text{max}} \) and \( \bar{v}_{\text{min}} \)) to the average velocity through the total section area (\( \bar{v} \)). These two parameters are plotted in Fig. 4-60 as a function of API standoff for three different power-law indices. As standoff decreases, the average velocity on the widest side first increases and then levels off. On the narrowest side, it decreases quickly toward negligible values. In addition, when the power-law index is low, the distortion of the velocity distribution is worse.

For fluids exhibiting a yield stress, the velocity reduction on the narrow side can be even more pronounced because the shear stress may be lower than the yield stress of the fluid, implying that the local velocity of the fluid is 0. For Bingham plastic fluids in particular, the dimensionless parameters relevant to the velocity distri-
bution are the same as for a power-law fluid, except that the power-law index is replaced by the dimensionless shear rate, \( \xi \). The effect of \( \xi \) on the velocity distribution is similar to that of the power-law index (i.e., the lower the value of \( \xi \), the higher the velocity distribution distortion). A critical dimensionless shear rate (\( \xi_{\text{crit}} \)) for the fluid to start flowing on the narrow side of the annulus can be defined (Chapter 5).

Pipe eccentricity also affects the friction-pressure/flow rate relationship. A typical example of friction-pressure reduction caused by eccentricity is shown in Fig. 4-61. The ratios of eccentric-annuli friction pressures to the corresponding concentric-annulus friction pressures are plotted against standoff for a power-law fluid with \( n = 1.0, 0.5, \) and 0.2. For narrow annuli, the relative friction-pressure reduction depends on the power-law index for power-law fluids and on the dimensionless shear rate for Bingham plastic fluids. Theoretically, the normalized friction pressure can vary between 1.0 and slightly less than 0.4 for shear thinning fluids.

As mentioned earlier, the uneven velocity distribution in eccentric annuli affects the transition to turbulent flow. Because the Reynolds number depends on the local average velocity and the annular gap, parameters that both vary around the annulus, turbulence is likely to appear first at the widest point in the annulus and extend all around the annulus as the flow rate increases. Consequently, laminar flow and turbulent flow regimes can coexist in a given eccentric annulus. Using the basic slot model, one can define the following.

- An average critical Reynolds number \((N_{Re1})_{ecc}\), at which laminar flow ends on the wide side of the annulus, represents the maximum average Reynolds number for the fluid to be in purely laminar flow all around the annulus.
- An average critical Reynolds number \((N_{Re2})_{ecc}\), at which the fluid begins to be in full turbulent flow on the narrow side of the annulus, represents the minimum average Reynolds number for the fluid to be in full turbulent flow all around the annulus.

These two parameters, normalized to the corresponding values for a concentric annulus \((N_{Re1} \) and \( N_{Re2} \)) are plotted in Figs. 4-62 and 4-63 for power-law fluids with three different power-law indices. These curves are typical of any nonelastic, shear-thinning fluid. They show that, as standoff decreases, the average Reynolds number range in which both flow regimes coexist becomes increasingly wider. The flow regime begins to be turbulent on the wide side of the annulus earlier than would be expected from concentric flow calculations. The fluid remains in laminar flow on the narrow side of the annulus later than expected from concentric flow calculations. Notice also that \((N_{Re1})_{ecc}\) is much more dependent on the power-law index than \((N_{Re2})_{ecc}\).

When a given fluid is in turbulent flow all around the annulus, the velocity distribution is less distorted. In addition, the friction-pressure reduction caused by eccentricity is less in turbulent flow than in laminar flow (Figs. 4-64 and 4-65).
As stated earlier, although the results presented above have not been fully validated quantitatively, their trends provide qualitative information concerning the effects of pipe standoff on the flow of wellbore fluids in the annulus. One can conclude that the effect of eccentricity should be taken into account when friction pressures play a significant role, for example U-tubing prediction in relatively small annuli (Chapters 5 and 12) or friction pressures in slim holes the velocity distribution plays a significant role (e.g., mud circulation).

Fig. 4-62. Maximum normalized average Reynolds numbers for different power-law fluids to be in laminar flow around an eccentric annulus \((d_w/d_o = 0.8)\). Reprinted with permission of SPE.

Fig. 4-63. Minimum normalized average Reynolds numbers for different power-law fluids to be in turbulent flow around an eccentric annulus \((d_w/d_o = 0.8)\).

Fig. 4-64. Ratio of average velocities on the wide and narrow sides of the annulus to the total average velocity for different power-law indices. Values are calculated using the basic-slot model in turbulent flow.

Fig. 4-65. Eccentric annulus/concentric annulus friction-pressure ratios \((d_w/d_o = 0.8)\) for different power-law indices calculated using the basic-slot model in turbulent flow.

Chapter 4 Rheology and Flow of Well Cement Slurries
4-7 Conclusions
Accurate and reliable rheological characterization of oil-well cement slurries still presents a problem for the industry. These fluids exhibit complex rheological behavior that depends not only on their composition and the mixing procedure (as explained in other chapters), but also on shear history, temperature, and the testing procedures.

Unless extreme care is taken, the coaxial-cylinder viscometer, most commonly used to measure the rheological properties of cement slurries, can suffer from a number of limitations resulting from particle migration, end effects, or slippage at the rheometer wall. Similar problems have been encountered with other types of equipment (e.g., pipe-flow rheometers). Therefore, coaxial-cylinder and vane rheometers remain the most useful instruments for characterizing cement slurries today. It is clear that research is needed to improve testing equipment and procedures.

Equations describing the flow of cement slurries in pipes and annuli have focused on three widely used rheological models—the power-law, Bingham plastic, and Herschel-Bulkley models. These models’ limitations have also been discussed, and some more realistic alternatives presented. Because of the lack of experimental data, the validity of many of these equations (at least in turbulent flow) is not yet fully established. Further progress in this domain depends on acquiring better characterizations of the rheological properties of cement slurries.

4-8 Acronym list
API American Petroleum Institute
ISO International Organization for Standardization
SVF Solid volume fraction
5-1 Introduction

Mud removal has been a subject of intense interest in the well-cementing community for many years because of its effect on cement quality and zonal isolation. The main objective of a primary cement job is to provide complete and permanent isolation of the formations behind the casing. To meet this objective, the drilling mud and the preflushes (if any) must be fully removed from the annulus, and the annular space must be completely filled with cement slurry. Once in place, the cement must harden and develop the necessary mechanical properties to maintain a hydraulic seal throughout the life of the well. Therefore, good mud removal and proper slurry placement are essential to obtain well isolation.

Incomplete mud displacement can leave mud channels or mud layers on the walls across the zones of interest, thereby favoring interzonal communication. Therefore, bonding of the cement to the pipe and formation, as well as cement-seal durability, are affected by the efficiency of the displacement process.

Mud removal in cementing operations is not fundamentally different from mud-to-mud displacement or mud-to-completion fluid displacement, although the means and objectives are slightly different.

- For a cementing engineer, the heart of the mud-removal process consists of optimizing casing centralization, selecting the sequence of fluids, determining the volume and properties of each of the fluids, and to some extent determining the pumping rate. Often, these are the only variables the engineer can control. Ideally, after determining the optimal fluid properties, one can determine the correct fluid compositions. In the end, the final objective is to achieve the most efficient zonal isolation. Success is most often evaluated using cement logs (Chapter 15).

- Mud displacement while drilling has a different objective: to replace one drilling fluid with another with a minimum amount of intermixing. Also, the conditions are different (e.g., the pipe-to-hole-diameter ratio is much smaller), and the evaluation method is direct: One monitors the amount of mixed fluid recovered on the surface.

- Mud displacement by completion fluids has yet another objective: to remove the maximum amount of suspended solids in the wellbore fluid. The result is evaluated by monitoring of the clarity of the returned fluid.

In all the above three domains—replacement of a drilling fluid by a cement slurry, another drilling fluid, or a completion fluid—the outlined technical objective is balanced by economic considerations, which include the rig time required for the displacement operations, the cost of the cleaning products, and the eventual loss of recovered fluid because of intermixing.

Mud removal before cementing is closely related to the borehole quality resulting from the drilling phase. From a chronological point of view, mud removal begins when drilling operations are completed.

1. The well is circulated and cleaned before and while the drillstring is pulled out. This process is known as mud conditioning.
2. The well is logged. During this process, the mud is mainly static.
3. Casing is run in and the mud is conditioned again.
4. Mud displacement and cement placement begin.

Krause (1986) calls the operations before mud displacement and cement placement “predisplacement” steps. In this text, these steps are discussed in Section 5-2 (Well preparation).

Research concerning the cement-placement process began in the 1930s. Some key factors influencing primary cement job failures were identified, and solutions were proposed as early as 1940. Using a large-scale simulator, Jones and Berdine (1940) showed that poor zonal isolation could be attributed to channeling of the cement slurry through the mud, a phenomenon they found to be promoted by casing eccentricity. They also identified that a residual mud filtercake at the cement/formation interface was caused by poor mud displacement. To minimize cement channeling, Jones and Berdine (1940) proposed casing centralization. They also found effective ways to remove the mud filtercake, including fluid jets, scrapers or scratchers, casing reciprocation, and pumping acid ahead of the cement slurry.
Since those early days, many theoretical, experimental, and field studies have been performed to better understand mud displacement. This is necessary partly because of the increasing complexity of the problem (e.g., deeper wells and deviated wells), together with the development of new knowledge. Unfortunately, the experimental and theoretical approaches suffer from severe limitations. At first glance, a theoretical approach seems attractive, because there are major drawbacks associated with experimental devices.

- One of the key parameters in the mud-removal process, the ratio of casing length to the annular gap, is difficult to reproduce. In the laboratory, one is typically limited to a ratio of about 500, while in the field the order of magnitude of this parameter is $10^4$. This prevents observation of, for example, axial deformation of fluid interfaces owing to eccentricity on a long length scale. Therefore, the effect of gravity in eccentric annuli cannot be fully investigated. One may argue that, in theory, the casing-length/annular-gap ratio could be maintained with an experimental device (reducing the annular gap to a very small value); unfortunately, this is not practical because dynamic similarity requires that at least six dimensionless parameters be matched to the corresponding field values.

- Second, in view of the number of parameters involved, an experimental displacement-efficiency investigation over the complete dimensionless parameter space would represent an enormous amount of work.

Therefore, one must be careful when attempting to extrapolate experimental results outside of the conditions within which they were obtained. It is also important to mention that some of the key parameters (e.g., rheology) are difficult to measure (Chapter 4). In addition, in most published experimental studies in which cement was used as the displacing fluid, little information is available regarding its compatibility with the displaced mud. Compatibility may strongly affect the results.

The theoretical approach also has its limitations. The complete modeling of the displacement process presents a formidable task, even for the most sophisticated computers. For example, one must contend with unsteady mass and momentum transfer between different non-Newtonian fluids in an asymmetric geometry. At present, the best models for field use are based on a two-dimensional (2D) representation of annular displacement (Bittleston et al., 2002). More complex three-dimensional (3D) models (King et al., 2000) remain limited by computational power. In addition, some of the key parameters cannot yet be modeled well (e.g., chemical interactions between fluids and static and dynamic filtercake deposition and erosion). Usually, the models assume that the fluids are separated by a sharp interface with no interfacial mixing.

It is worthwhile to mention that attempts to model interfacial instabilities caused by density or viscosity differences are still at an early stage. They are often limited to two dimensions and are valid only for Newtonian fluids. Incidentally, such instabilities have been observed experimentally by Tehrani et al. (1993), and they can lead to enhanced mud removal (Section 5-3.6). In the last 10 years, progress has been made by combining experimental and theoretical studies (Vefring et al., 1997; Biezen et al., 2000; Frigaard et al., 2001) with attempts to apply new models developed in other industries. For example, hole-cleaning models have been adapted to mud-removal situations (Nguyen, 1997).

Despite these technical advances, the accuracy of predictions is still limited. Predictions are expressed in terms of chance of success, which is a clear acknowledgement that all of the phenomena are not under control.

Field data supporting successful cementing practices are cited in this chapter. However, it is difficult to quantify the success of a job for the following reasons.

- Controlling and monitoring an actual cement job is not as easy as in a laboratory experiment.
- The properties of fluids mixed in the field are often not measured, and they can be quite different from laboratory-mixed systems. Similarly, the wellbore conditions are often not accurately known.
- There is no direct method to measure mud removal, so indirect evaluation techniques are used. Interpretation of the measurements is often not straightforward (Chapter 15).

Remaining technical challenges include developing a better quantification of the effects of casing movement during placement, chemical interactions between fluids, and unstable flow situations. Although it is possible to predict the fluid properties that will provide optimal mud displacement, it remains a tedious process to formulate such fluids.

The link between fluid performance in the laboratory and the field also requires further study to develop laboratory procedures that are representative of downhole conditions. Such procedures would assess the effectiveness of a proposed solution. Of course, any new procedures must be accepted by industry standardization organizations such as the American Petroleum Institute (API) and the International Organization for Standardization (ISO) (Appendix B).

Despite all of the problems cited above, a few areas of industry consensus have emerged regarding the optimal design of a primary cement job for successful mud
removal and cement placement. This chapter distinguishes areas of consensus from those of controversy. The organization of the chapter is outlined below.

1. **Well preparation.** This section focuses on mud conditioning and circulation. This is a key point, because the success of a primary cement job largely depends on the suitability of the wellbore for cementing.

2. **Mud displacement.** This section discusses various methods and important considerations in removing mud.
   a. The ideal case of mud displacement in a concentric annulus between two impermeable walls (the so-called *mobile* mud)
   b. Effects of eccentricity
   c. The difficult problem of removing the *immobile* mud, which can easily be bypassed by the displacing fluid
   d. Casing movement strategies to overcome some of the previously described problems and contribute to the success of critical primary cementing jobs

3. **Drilling fluids, spacers, and washes.** This section outlines the basic properties and chemistries of drilling fluids, spacers, and washes, and why they are required

4. **Other cement placement problems.** This section discusses the mixing of fluids as they travel down the casing when no mechanical plugs are used and contamination of the shoe once cement is placed

5. **Qualitative recommendations.** The chapter concludes with qualitative recommendations for achieving successful mud removal and cement placement.

### 5-2 Well preparation

C.W. Sauer (1987), in his review on the state of the art of mud displacement, noted that events occurring during the drilling and casing phases will affect the cement job. “It should not be believed that the cement job should go all right regardless of what else is or has taken place during the drilling to casing point.”

A poorly drilled hole may have large dogleg sections, preventing engineers from running casing with the proper number of centralizers. Crooked holes make casing centralization difficult; consequently, the removal of the mud from the narrow side of the annulus is problematic. Poorly treated mud could induce washouts, thick filtercakes, or settled solids beds, which would be difficult or impossible to remove. The hole may also have several washed-out zones that are difficult to clean out, regardless of the displacement rate. Furthermore, these washed-out pockets tend to hold gelled or dehydrated mud that may be dragged out by the cement slurry, contaminating the cement column above. While good drilling practices do not guarantee a successful cement job, they may prevent a failure.

Although it is understandable that the objective for the drilling engineer is to drill the well safely and as quickly and economically as possible, this should be accomplished bearing in mind that one of the ultimate goals of drilling is to provide an optimal wellbore for subsequent operations. In summary, well operations and especially cementing require “a team effort that must include drilling management, drilling operations, drilling engineering, rig contractor, and service personnel. (It is not) a process that starts when the pipe is on bottom. It must start during the drilling of the hole to be cemented” (Sauer, 1987).

#### 5-2.1 Borehole quality

A borehole in good condition for cementing operations has the following attributes:
- controlled subsurface pressures
- a smooth wall with doglegs of low severity
- in-gauge (i.e., the expected diameter according to the bit size)
- stable (i.e., free of formation encroachment or spalling)
- clean (i.e., free of cuttings)
- a correctly treated and mobile mud that will deposit thin filtercakes in front of permeable zones.

Unfortunately, such an ideal situation cannot always be achieved. Therefore, cement-placement techniques often must be designed to minimize the influence of poor well preparation.

Failure to achieve these requirements may have the following consequences:
- differential sticking problems while logging or running the casing
- high drag forces, preventing the running of casing to the planned depth
- influxes or losses while running the casing
- poor mud removal resulting in poor cement placement.

Some of these requirements are highly dependent upon the drilling method. For example, traditional directional drilling in sliding or rotating mode has a tendency to lead to helicoidal or undulating trajectories. The more recent techniques of rotary steerable drilling (Schaaf et
al., 2000), together with optimized drilling bits—which drill with less instability (Mensa-Wilmot and Stacey, 2001)—provide much smoother and easy-to-clean wellbores (Downton et al., 2000; Gaynor et al., 2001).

The most common method to clean cuttings out of the wellbore is to periodically pump viscous fluids while rotating the pipe at 150 to 200 rpm, if possible (Sewell and Billingsley, 2002). It is also important to remove viscous pills before cementing. This method has emerged from field practices rather than from physical or phenomenological studies. Even if the borehole is clean after the drillstring has been pulled out, special care must be taken to maintain a good-quality hole until the beginning of cementing operations. Long static periods favor barite settling in deviated sections and the development of thick mud filtercakes that are difficult to remove and that impair running the casing.

Assessing the quality of the hole before running the casing requires caliper and survey logs. A thick mud filtercake can be misidentified as an undergauge hole (Al Khayyat et al., 1999).

5-2.2 Circulation and displacement efficiency

The most common parameter to define the ability of a fluid to displace another is the displacement efficiency. When the same fluid is used to displace itself, this parameter is called the circulation efficiency.

Consider an annulus of volume $V_{ann}$ and length $L$ that is filled with Fluid No. 1 (the fluid to be displaced) flowing at a given volumetric rate $q$ (Fig. 5-1). At time $t = 0$, Fluid No. 2 (the displacing fluid, which may be fresh mud) suddenly replaces Fluid No. 1 at the inlet of the annulus ($Z = 0$). At any time $t > 0$, the displacement efficiency $\eta_{disp}$ is the fraction of annular volume occupied by Fluid No. 2. In other words, for case (d) in Fig. 5-1, the displacement efficiency would be $1 - \frac{\text{hatched area}}{\text{area between } z = 0 \text{ and } z = 1}$. The natural time scale that allows one to define a nondimensional time, $t^*$, is the ratio of the annular volume, $V_{ann}$, to the flow rate, $q$.

$$t^* = t \times \frac{q}{V_{ann}} \quad (5-1)$$

This dimensionless time is equal to the number of annular volumes pumped. Notice that, with these definitions, $\eta_{disp}$ is equal to $t^*$ [case (b)] until Fluid No. 2 first appears at the outlet of the annulus [case (c)]. This is defined as the breakthrough time, $t^{*}_{break}$. After breakthrough [case (d)], $\eta_{disp}$ approaches but never reaches a constant value that may be less than 1, indicating that the annulus still contains undisplaced Fluid No. 1 (Fig. 5-2). There is no restriction in using this definition. It applies to any situation, including, for example, when the casing is moved.

**Fig. 5-1.** Schematic diagram of interface profiles at different times during the displacement of Fluid No. 1 by Fluid No. 2.

**Fig. 5-2.** Schematic of a displacement-efficiency curve, with an asymptotic value equal to unity.
The circulation efficiency may easily be monitored in the field. For example, one can use carbide pills (Section 5-2.4.7). Or, for simple situations, numerical models may be used to predict the evolution of the efficiency as a function of the pumped volume. A difference between the measured and predicted values is that the measured efficiency considers the internal casing or drillstring volume plus the annular volume, while the models are limited to the annular volume. This difference is usually negligible, as mixing and fingering inside of tubulars is insignificant compared with that observed in the annulus. During cementing, when wiper plugs are used, no mixing is possible inside the tubulars unless their premature wear leaves a layer of mud on the casing walls (Chapters 11 and 13).

The circulation or displacement efficiency is a clear and simple concept; however, it can sometimes be misleading, especially for high eccentricities. Under such circumstances, a large angular channel of bypassed mud in the narrow part of the annulus would correspond to a small proportion of the total flow area. This situation is illustrated in Fig. 5-3. Around most of the casing the displacement is very efficient; however, there is a continuous mud channel. In addition, a thin layer of mud may remain immobile on the formation and casing walls. Again, the corresponding volume of fluid will be small, but this can affect cement logs significantly if the mud is in contact with the casing.

In Fig. 5-3, each rectangle at the upper right represents an annulus at a given time. It is produced by mathematically “unwrapping” the annulus. Each set of five rectangles represents a progression in the circulation from 0.2 to 1 annular volume. The set on the left shows a single non-Newtonian fluid displacing itself. The set on the right shows an 8.33-lbm/gal \([1,000-\text{kg/m}^3]\) fluid displaced by an 11.7-lbm/gal \([1,400-\text{kg/m}^3]\) fluid. The density contrast induces azimuthal flows, and the displacement is significantly improved, although some fluid is still left behind on the narrow side.

![Fig. 5-3. Schematic diagrams of bypassed mud in an eccentric annulus and a photograph of an actual mud channel between two casings (Bittleston and Guillot, 1991; Piot, unpublished diagrams and photograph).](image)
5-2.3 Mud conditioning

Drilling muds are designed to facilitate drilling operations and provide proper cuttings transport. They are not necessarily conducive to efficient mud displacement, logging, or completion operations. Therefore, it is often necessary to condition the mud (i.e., to modify its properties). Before placing cement in the wellbore, two mud characteristics can be changed—density and rheology. The required adjustments vary according to the particular situation. This issue will be discussed in detail later.

It is generally desirable to reduce the mud density without compromising well control. Reducing the mud’s gel strength, yield stress, and plastic viscosity is also beneficial. Doing so reduces the driving forces necessary to displace the mud and increases mud mobility. Of course, these steps require prior removal of the cuttings from the borehole and the drilling fluid. When the cuttings are removed from the drilling fluid, its yield point usually decreases. One must be careful to prevent settling of weighting agents (e.g., barite); otherwise, control of mud density is lost. This may represent a major constraint for highly deviated holes (Crook et al., 1987) in terms of minimum values for the low-shear-rate rheology.

Once the mud is clean, its rheology can be further modified by adding dispersants, water, or base oil (which also reduces the density). It is necessary to circulate the mud until its rheological properties fall within the desired range.

This requires circulation for at least one hole volume, which ideally should be performed before removing the drillpipe. Otherwise, unconditioned mud may have sufficient time to gel while the crew is removing drillpipe, logging, and running casing.

Moving the drillstring during conditioning aids the displacement of gelled mud and helps keep the cuttings suspended. High-speed pipe rotation is particularly beneficial in horizontal sections because of the orbital movement of the string, while in deviated sections, reciprocation allows the string to move up and down the hole (Al Khayyat et al., 1999; Section 5-2.4.4).

The running of casing should be performed carefully to avoid fracturing the formations. The equivalent flow rate in the annulus \(q_{\text{ann}}\) as a function of the speed at which the casing is run \(v_{\text{run}}\) is given by the following equation:

\[
q_{\text{ann}} = v_{\text{run}} \times A_{\text{pipe}},
\]

where \(A_{\text{pipe}}\) = cross sectional area of pipe.

A quick calculation shows that these rates are not negligible. For example, a 7-in. outside diameter (OD) pipe run at 3 ft/s [1 m/s] gives rise to an annular flow rate of 8.6 bbl/min [23 L/s]. Because the casing is not run continuously, the velocity is not constant, and inertial forces also contribute to the annular pressure. Mathematical models for calculating the associated pressure surges can be found in the literature (Mitchell, 1988; Zamora et al., 2000).

The mud should be circulated after the casing is in place, because the well may have been static for a long period, allowing the mud to gel or build a filtercake. The minimum circulation volume should be at least “bottoms up” (pumping one annular volume; the internal volume of the tubulars is ignored), and preferably greater. Mud circulation is also beneficial because it

- helps clean cuttings out of the hole
- ensures that gas flow is not occurring
- helps detect any gas flow into the well
- homogenizes the mud after treatment on the surface
- reduces the yield stress and plastic viscosity because most drilling muds are thixotropic
- erodes the gelled or dehydrated mud that is trapped in washouts, on the narrow side of an eccentric annulus, and at the walls of permeable formations (because the shear stress exerted by the flowing mud is usually less than the shear strength of the mud film, this erosion is only possible if the hydraulic action of the fluid is supplemented by casing movement, especially when scratchers are installed on the casing (Chapter 11)).

Unfortunately, at this stage, operators commonly perform only mud conditioning.

If cuttings, or gelled or dehydrated mud, are scraped into the mud while running the casing, an excessive pressure buildup can occur when circulation is resumed. Therefore, it is often desirable to circulate the annulus at intermediate depths before the casing reaches the bottom of the hole.

These qualitative recommendations are only marginally helpful for the completion engineer, who must design the mud-circulation phases before removing the drillpipe and after the casing is in place. For a better understanding of the relative importance of each parameter, it is possible to use mathematical models that predict mud circulation. However, continuous monitoring of mud circulation remains the best method to verify adequate mud conditioning.

5-2.4 Modeling mud circulation

Modeling mud circulation is a fluid-mechanics problem that can be solved without making too many assumptions; therefore, the predictions have practical value. The model describes the isothermal flow of an incompressible and inelastic fluid in the annulus between two
pipes. The principal part of the solution is the fluid-velocity profile calculation, which accounts for the correct rheological model and boundary conditions. Walton and Bittleston (1991) calculated the flow of a fluid with a yield stress in a narrow eccentric annulus, allowing the identification of various flow regimes as the flow rate increases (Fig. 5-4).

Bittleston and Hassenger (1992) considered the flow of viscoplastic fluids in a concentric annulus during casing rotation. Barton et al. (1994) presented a flow simulation of a Herschel-Bulkley fluid in an eccentric annulus during casing rotation or reciprocation. These models are briefly introduced below, along with the effects of flow regime, eccentricity, and casing movement.

The effects of gelled mud and mud filtercake are discussed; however, the models do not consider them directly. Nevertheless, the models are valid in a qualitative sense, and they allow one to consider the worst-case scenario. The notations used in this chapter are the same as those defined in Chapter 4, where the basic flow equations are presented.

### 5.2.4.1 Laminar flow in a concentric annulus

In laminar flow, the circulation efficiency can be calculated by tracking marked particles. This is done by computing the velocity profile and solving the streamline equations. For a concentric annulus, the circulating efficiency is directly derived from the nonzero velocity component described in Chapter 4. The data given in this section were calculated using either the rectangular-slot approximation (Chapter 4 and Appendix A, Table A-8) or the finite-element solution of the true annular flow. In Fig. 5-5, the circulation efficiency is plotted versus the number of annular volumes. For power-law fluids, the curve depends only upon the power-law index, \( n \). For Bingham plastic fluids, it also depends upon a single parameter, the dimensionless shear rate, \( \xi \), given by

\[
\xi = \frac{12\bar{v}}{d_o - d_w} \left( \frac{\mu_p}{\tau_y} \right),
\]

where

- \( d_o = \) outer diameter of annulus
- \( d_w = \) inner diameter of annulus
- \( \bar{v} = \) average fluid velocity
- \( \mu_p = \) plastic viscosity
- \( \tau_y = \) yield stress of the Bingham plastic fluid.

For Herschel-Bulkley fluids, two parameters are involved—the power-law index and a dimensionless shear rate now defined as

\[
\xi = \frac{12\bar{v}}{d_o - d_w} \left( k \right)^{1/n} \left( \frac{\tau_y}{k} \right)
\]

where

- \( k = \) consistency index
- \( \tau_y = \) yield stress of the Herschel-Bulkley fluid.

Notice that the breakthrough time corresponds to the ratio of the average velocity to the maximum velocity. As explained in Chapter 4, this value is equal to \( \frac{2}{3} \) for Newtonian fluids in a slot and is higher for shear-thinning fluids. After breakthrough, the efficiency approaches 100%, a value that theoretically can be reached at infinite time, because the velocity of the fluid particles at the annular walls is assumed to be zero (no wall slip).

Figure 5-5 also shows that, as a fluid becomes more shear-thinning (i.e., as the power-law index, the dimensionless shear rate, or both become smaller), circulation

---

**Fig. 5-4.** Flow regimes for fluids with yield stress flowing in an eccentric annulus as the flow rate is increased (Walton and Bittleston, 1991). Copyright Cambridge University Press.
**Fig. 5-5.** Circulation-efficiency plots for various fluids in a narrow concentric annulus. Top: Circulation efficiency for Newtonian and power-law fluids. Middle: Circulation efficiency for Bingham plastic fluids for various dimensionless shear-rate values. Bottom: Circulation efficiency for a Herschel-Bulkley fluid at different flow rates (in bbl/min).
will become more efficient. A circulation efficiency of 100\% at the breakthrough time would occur with an entirely flat velocity profile (which is equivalent to a power-law index or a dimensionless shear rate of zero). As shown in Table 5-1, the dimensionless shear-rate values in Fig. 5-5 correspond to typical field conditions. High dimensionless shear-rate values correspond to a low yield-stress/wall-stress ratio, while low values are close to plug-flow conditions. In this table, \( \psi \) is the dimensionless shear stress that is equal to the ratio of the fluid yield stress to the wall shear stress.

It is also important to point out that, for power-law fluids, circulation efficiency does not depend on the flow rate. However, for fluids with a yield stress, the flow rate is important. Thus, everything else being equal, the circulation efficiency in a concentric annulus improves under the following conditions.
- Decreasing average velocity
- Increasing annular-gap size
- Decreasing \( \mu_p/\tau_y \) or \( k/\tau_y \) ratio (Fig. 5-6)

### 5-2.4.2 Turbulent flow in a concentric annulus

The flatter average velocity profiles that result from turbulent flow (Chapter 4) generally give much higher circulation efficiencies than those for laminar flow. However, calculating the circulation efficiencies is much more complicated. A detailed discussion is beyond the scope of this chapter. The interested reader is invited to review textbooks by Schlichting (1979) and Nauman and Böhm (1983).

#### 5-2.4.3 Influence of string eccentricity

Although this section discusses the effect of eccentricity on circulation efficiency, it also addresses the effects of asymmetric flow geometry caused by oval holes. The qualitative effect of casing eccentricity on velocity profiles and pressure gradients was presented in Chapter 4, using the basic-slot model. When the inner pipe of an annulus is not centered, the velocity distribution around the annulus is distorted, and the flow favors the wider side. This may lead to unusual situations in which the flow regime can be laminar on the narrow side of the annulus and turbulent on the wide side (Fig. 5-4), because the local Reynolds number varies azimuthally around the annulus (see Eq. 4-131 for the definition of the local Reynolds number).

<table>
<thead>
<tr>
<th>Hole Size, ( d_o ) (in. [mm])</th>
<th>Pipe Outside Diameter, ( d_w ) (in. [mm])</th>
<th>Fluid Plastic Viscosity, ( \mu_p ) (cp [mPa-s])</th>
<th>Fluid Yield Stress, ( \tau_p ) (lbf/100 ft (^2) [Pa])</th>
<th>Flow Rate, ( q ) (bbl/min)</th>
<th>Velocity, ( \dot{v} ) (ft/s [m/s])</th>
<th>Dimensionless Shear Stress, ( \psi )</th>
<th>Dimensionless Shear Rate, ( \xi )</th>
</tr>
</thead>
<tbody>
<tr>
<td>8(\frac{1}{2}) [216]</td>
<td>7 [178]</td>
<td>50 [50]</td>
<td>15 [7.2]</td>
<td>8 [21]</td>
<td>5.9 [1.8]</td>
<td>0.18</td>
<td>4.07</td>
</tr>
</tbody>
</table>

**Fig. 5-6.** Variation of circulation efficiency for an annular volume of 1 versus flow rate for two Herschel-Bulkley fluids in a centered, narrow concentric annulus. Rheograms of the fluids are shown on the bottom plot. Fluid 1: \( k = 0.02 \text{ Pa-s}^{-n} \), \( n = 0.9 \), \( \tau_y = 2 \text{ Pa} \). Fluid 2: \( k = 0.03 \text{ Pa-s}^{-n} \), \( n = 0.8 \), \( \tau_y = 3 \text{ Pa} \).
When the flow around the annulus is laminar, the effect of eccentricity on circulation efficiency can be derived from the calculated velocity profiles. The results for a Newtonian fluid are plotted in Fig. 5-7 (assuming the diameter ratio $d_w/d_o = 0.8$). In this simple case, the circulation efficiency only depends on the pipe standoff and the volume pumped.

The situation is more complex for shear thinning fluids. When standoff decreases, the distortion of the velocity profile is such that the breakthrough time occurs earlier and the circulation efficiency deteriorates (Chapter 4). In eccentric annuli, such fluids have a more uneven velocity distribution, and the effect of eccentricity on the circulation efficiency is even more pronounced. The breakthrough time, $t_{\text{break}}$, and the rate at which the circulation efficiency increases after breakthrough are reduced to a greater extent with decreasing standoff.

For power-law fluids, with the casing-to-hole diameter ratio close to 1, the circulation efficiency at a given number of annular volumes pumped depends upon the pipe standoff and the power-law index. Typical examples of circulation efficiency curves for a power-law index of 0.5 are shown in Fig. 5-8.

For Bingham plastic fluids, the circulation efficiency depends upon the pipe standoff and the dimensionless shear rate. For different standoffs, Fig. 5-9 shows the circulation efficiency of a Bingham plastic fluid flowing at a rate such that the dimensionless shear rate $= 0.178$

Comparing Figs. 5-8 and 5-9 to Fig. 5-7 confirms that shear thinning fluids are much more affected by pipe eccentricity than Newtonian fluids. The velocity distribution is sensitive to the power-law index or the dimensionless shear rate. Typically, for standoffs less than 80% to 90% (compare Fig. 5-5 to Fig. 5-8 and Fig. 5-9) and a given number of annular volumes, the more shear thinning the fluid, the worse the circulation efficiency. Therefore, in this standoff range, the circulation efficiency of power-law fluids will increase with the power-law index. For Bingham plastic fluids, the higher the dimensionless shear rate, the better the circulation efficiency will be (Table 5-2). Thus, for such standoffs, the circulation efficiency can be improved by increasing the flow rate or increasing the $\mu_p/\tau_y$ ratio. As mentioned earlier, the opposite is true for concentric annuli. Because a perfectly concentric annulus never exists in the field, recommendations for improving circulation efficiency in eccentric annuli rather than concentric annuli should be adopted.

It is important to note that the circulation efficiency is more sensitive to the standoff than to the dimensionless shear rate (Fig. 5-10). If the dimensionless shear rate increases by a factor of 50, the circulation efficiency varies by no more than 10%. As the standoff increases to

<p>| Table 5-2. Minimum Flow Rates Required to Achieve Complete Flow Around the Annulus† |</p>
<table>
<thead>
<tr>
<th>Standoff (%)</th>
<th>Minimum Flow Rate (bbl/min [L/s])</th>
<th>Laminar Flow Around the Annulus</th>
<th>Mixed-flow Regime (Laminar and Turbulent) Around the Annulus</th>
</tr>
</thead>
<tbody>
<tr>
<td>80</td>
<td>2.0 [5.3]</td>
<td>2.0 [5.3]</td>
<td></td>
</tr>
<tr>
<td>60</td>
<td>11 [29.3]</td>
<td>11 [29.3]</td>
<td></td>
</tr>
<tr>
<td>40</td>
<td>38 [101]</td>
<td>19 [50.5]</td>
<td></td>
</tr>
<tr>
<td>20</td>
<td>&gt;100 [&gt;266]</td>
<td>33 [87.8]</td>
<td></td>
</tr>
</tbody>
</table>

†Rates are calculated for a Bingham plastic fluid under two conditions: single-flow regime (laminar flow) and mixed-flow regime (laminar and turbulent flow).

![Figure 5-7](image-url)  
*Fig. 5-7. Circulation efficiency for Newtonian fluid in an eccentric annulus, calculated using a finite-element model ($d_w/d_o = 0.8$), for various standoff values.*
Fig. 5-8. Circulation efficiency for a power-law fluid in an eccentric annulus, calculated using a finite-element model ($d_w/d_o = 0.8$, $n = 0.5$), for various standoffs.

Fig. 5-9. Circulation efficiency for a Bingham plastic fluid in an eccentric annulus, calculated using the finite-element model ($d_w/d_o = 0.8$, $\xi = 0.178$).

Fig. 5-10. Circulation efficiency for a Bingham plastic fluid after one hole volume. Sensitivity to dimensionless shear rate and standoff.
90% from 50%, the effect on the circulation efficiency is more dramatic.

Among shear thinning fluids, those exhibiting a yield stress present a specific case for the following reason. When the flow rate is sufficiently low, such fluids are stationary in the narrowest part of the annulus. The shear stress is less than the yield stress. The basic-slot model shows that this will occur if the shear stress at the wall, $\tau_w(L)$, calculated for a local annular gap, $L$, is such that

$$\tau_w(L) = \frac{L}{2} \times \left( \frac{dp}{dz} \right)_f < \tau_y. \quad (5-5)$$

This situation is not desirable during mud circulation, because the circulation efficiency would asymptote toward a value smaller than 1 (Fig. 5-9). To avoid this, it is necessary to have all of the fluid moving around the annulus. This can be achieved if the minimum shear stress at the wall (i.e., the shear stress at the wall at the minimum annular gap $L_{min} = R_{STO}(d_o - d_w)/2$) is greater than the yield stress. Figure 5-11 shows the variation of wall shear stress versus angular position.

$$\left( \frac{dp}{dz} \right)_f > \frac{4\tau_y}{R_{STO}(d_o - d_w)} \text{ or } \psi < R_{STO} \quad (5-6)$$

where

$R_{STO} = \text{standoff ratio (\%)}$.

For a Bingham plastic fluid, the corresponding minimum dimensionless shear rate to have fluid movement around the annulus can also be determined using the basic-slot model. For various standoffs, Table 5-2 shows the minimum flow rates necessary to achieve laminar flow all around the annulus. However, this is often not the case, especially at low standoff, because the fluid might not be in laminar flow on the wide side (Chapter 4).

For example, consider a mud with a plastic viscosity of 20 cp [20 MPa-s] and a yield stress of 10 lbf/100 ft$^2$ [4.79 Pa], flowing in a 12\%\-in. OD, 9\%\-in. inside diameter (ID) annulus. The data presented in Table 5-2 show the minimum flow rates necessary to achieve flow around the annulus, calculated for two conditions:

- the fluid is flowing in laminar flow all around the annulus
- the fluid on the wide side may be flowing in turbulent flow.

One can see that, at low standoffs, the minimum flow rate can be overestimated if flow is assumed to be truly laminar everywhere.

The effect of pipe standoff on the transition from laminar to turbulent flow is discussed in Chapter 4. Once a fluid is in turbulent flow around the annulus, there is much less distortion of the velocity distribution when compared to a laminar flow situation. The velocity field is also not sensitive to the shear-thinning behavior of the fluid. To the best of the authors’ knowledge, there is no published model for predicting circulation efficiency under such conditions. However, the efficiency is bound to be much better than in laminar flow.

![Fig. 5-11. Variation of wall shear stress around an eccentered annulus (standoff of 66%), at the minimum condition for having all the fluid in movement according to Eq. 5-5.](image-url)
5-2.4.4 Effect of casing movement

Rotating the drillstring aids the cleaning of cuttings from deviated boreholes (Sanchez et al., 1999). One can also expect a similar positive effect on mud circulation and displacement. Indeed, this practice is part of the “good cementing practices” detailed in Table 5-4.

The two basic ways to move tubulars are rotation and reciprocation along their axes. Secondary movements may also occur that have an even greater effect on the mud-circulation efficiency.

- When rotating at high speed, the tubular starts to have an orbital or whirling movement in addition to rotation around its axis (Fig. 5-12).
- When reciprocating in inclined sections, the pipe has an alternating up and down or lateral movement in a section of the well in addition to axial movement.
- Pipe rotation also induces Taylor vortices that increase the wall shear stress. Taylor vortices are toroidal or helicoidal flows that result from a combination of mean axial flow and azimuthal flow (Fig. 5-13). The induction of Taylor vortices is believed to be one of the main reasons why one sees increased annular friction pressure during pipe rotation (Philip et al., 1998).

![Fig. 5-12. Schematic diagram showing orbital or whirling pipe motion during rotation and lateral pipe motion during reciprocation.](image)

![Fig. 5-13. Annular flow patterns.](image)
Sanchez et al. (1999) mention that “it is the orbital motion and not the rotation that improves hole cleaning.”

Using reasonable assumptions, the effects of tubular movement on the fluid-velocity map in a cross section can be calculated using finite-element methods. However, for the secondary movements discussed above, only experimental and field observations are available. Therefore, the following discussion is restricted to the effects of the primary movements.

Speers et al. (1987) developed numerical models to study the influence of casing movement on the flow pattern of simple non-Newtonian fluids (power-law or Bingham plastic fluids) flowing in laminar flow. Similar results were presented by Bittleston and Guillot (1991). Circulation efficiencies derived from these models show that casing movement can indeed partially counteract the detrimental effect of pipe eccentricity (Figs. 5-14 and 5-15). However, it must again be emphasized that these models do not account for lateral motion of the casing—a likely occurrence during reciprocation and rotation at high rotary speed (McLean et al., 1967). In Fig. 5-15, note that rotation is found to be more effective than reciprocation for displacing mud at intermediate standoff values.

When performed in combination with scratchers, scrapers, or cable wipers (Chapter 11), casing movement mechanically erodes the filtercake and considerably improves the displacement process (Table 5-4). The effects of these mechanical devices on mud circulation are poorly quantified; however, there is no doubt that they contribute significantly to the efficiency of the process (Smith and Ravi, 1991). With some muds the filtercake redeposits quickly after scraping and becomes tougher with age.

Other techniques or effects are available to help remove the immobile mud or deposits. These include:

- jetting using a special pipe shoe while running casing in the hole (Way et al., 2000)
- rotating the tubular to allow Taylor vortices to develop, which may significantly increase mud circulation (Erbil, 1995)
- vibrating the casing during circulation to break adhesion because of static gel strength (Sutton and Ravi, 1991) (while this technique is hardly applicable in the field, vibration certainly occurs when rotating the casing at high rotary speed)
- reverse circulating the fluid—down the annulus and up the tubular (commonly done in completion operations but is rarely possible while running the casing)
- using specially designed hardware elements placed around the casing for inducing spiral flow or turbulence to help displace immobile mud or deposits in the vicinity of the tool (these tools can be specially designed centralizers [Kinzel and Martens, 1998]).

![Fig. 5-14. Fluid velocity maps comparing casing rotation (right) versus no rotation (left) while pumping a Bingham plastic fluid (from Bittleston and Guillot, 1991).](image-url)
Fig. 5-15. Top row, left: Velocity map for 20% standoff for a Newtonian fluid. Top row, right: Same map for a Herschel-Bulkley mud at 800 L/min. Center row, left: Same Herschel-Bulkley fluid with casing rotation at 6 rpm. Center right: Same Herschel-Bulkley fluid with casing reciprocation at 9 m/min. Bottom: Circulation efficiency at one annular volume versus standoff, with and without casing movement, for a Herschel-Bulkley fluid.
5-2.4.5 Discussion of theoretical models

The theoretical models mentioned above are sufficiently sophisticated to allow reasonable simulations of the principal steady-state hydrodynamic factors. However, several important parameters are still not taken into account because of limited knowledge of their physics and the overlapping nature of their effects.

- Mud thixotropy
- Mud filtercake and solids-bed formation and erosion
- Lateral movement of tubulars
- Effects of casing hardware
- Temperature profile

In recent years, cuttings-transport models have been extended to mud circulation. Prototype models exist, but they cannot be used routinely to solve field problems (Nguyen, 1997; King et al., 2000).

5-2.4.6 Removing gelled mud and mud filtercake during the circulation process

The theoretical results presented thus far are based on the assumption that the annulus is filled with a fluid of uniform properties. In practice, however, three effects complicate the analysis.

- Drilling fluids are thixotropic. Upon rest or low-shear conditions, their yield stress increases with time. For instance, the mud filling a large washout may be partially immobile and develop a high gel strength.
- In front of permeable formations, filtercakes are deposited (Chapter 6). Filtercakes may have widely varying properties depending on the fluid chemistry and on whether filtration takes place in a dynamic or static regime.
- In deviated sections, the solids that should be carried by the drilling mud may settle on the low side, building a bed. These solids could be cuttings or weighting material.

In these situations, part of the annulus will be locally filled with a material with different properties than those of the flowing mud (Fig. 5-16). This material may be removed in various ways during mud circulation. Channels of gelled mud, mud filtercake, or solids beds have different effects on zonal isolation. In addition, different methods are required to remove them.

- They do not form at the same places in the well.
- Their mechanical and chemical properties differ widely.
- Their response upon contact with cement will be different.

![Fig. 5-16. Schematic diagram of the potential occurrences of gelled mud and solids layers (Mathis et al., 2000). Reprinted with permission of SPE.](image-url)
5-2.4.6.1 Gelled mud

When allowed to remain static, most drilling muds develop a structure that is characterized by gel strength. Gel strength represents the minimum shear-stress value, \( \tau_{gel} \), necessary to induce flow. Drilling muds are designed to exhibit thixotropic properties, because they must be able to suspend cuttings and the weighting agent when circulation is stopped. Thus, gelled mud can be found everywhere in the hole when circulation is stopped. While the mud is being circulated, wellbore ovality, irregularities (washouts), and casing eccentricity can create zones in which the local fluid velocity is zero. Such mud is commonly called the **immobile mud**.

Immobile mud is partially responsible for the wellhead pressure peak when circulation is resumed. If channels or layers of immobile mud are left in the hole after cement placement, they may dehydrate and shrink while the cement sets, leaving an empty space. This empty space compromises zonal isolation, allowing formation fluids to flow along the well.

Gelled mud can return to its original state if a sufficient amount of shear is applied. The minimum shear required to restore movement is the yield stress or gel strength. Much has been published concerning the gel strength development of muds as a function of time. Garrison (1939) found that, depending on the fluid chemistry, bentonite muds can require a few minutes to 50 hours for gel formation fluids to flow along the wall.

Gelled mud can return to its original state if a sufficient amount of shear is applied. The minimum shear required to restore movement is the yield stress or gel strength. Much has been published concerning the gel strength development of muds as a function of time. Garrison (1939) found that, depending on the fluid chemistry, bentonite muds can require a few minutes to a few hours to develop a stable gel strength. The gel strength value is also dependent on the way it is measured, in particular the applied shear rate. This observation is a clear indication of the complex kinetics and equilibria between gel-structure formation and rupture (Darley and Gray, 1988).

Thus, the interpretation of the experimental results obtained by the standard oil industry procedure (Chapter 4; Appendix B) is questionable. For day-to-day applications, the situation is even worse, because the standard practice for measuring the gel strength consists of readings after 10 sec and 10 min. Ten minutes is not representative of the long static periods that muds can experience before being circulated (several hours or even days). Once the gel strength is exceeded, it is usually assumed that the mud instantaneously regains its previous rheological properties.

Based on the above simplifying assumptions, gelled mud can be restored to flowing mud if the shear stress is equal to the gel strength, \( \tau_{gel} \). The corresponding minimum friction pressure to achieve flow on the narrow side of an ecenterced annulus is similar to Eq. 5-6.

\[
\left( \frac{dp}{dz} \right)_f > \frac{4 \tau_{gel}}{R_{STO} (d_o - d_w)} \quad \text{or} \quad \psi < \frac{\tau_y}{\tau_{gel}} \quad (5-7)
\]

For practical use, the flow rate corresponding to this friction pressure is calculated as if no static gelled mud exists in the annulus. This provides a conservative estimate of the minimum required flow rate. In this way, one can only determine whether mud is flowing on the narrow side of the annulus, not the velocity at which it is flowing.

5-2.4.6.2 Mud filtercake

The presence of a mud filtercake at the wall of permeable formations is another factor that affects the circulation process. When mud is flowing across a permeable zone, it is subjected to dynamic filtration and then to static filtration when the flow is stopped (Chapter 6).

There is a possible relationship between mud filtration and pipe eccentricity that would be detrimental to the circulation process. Because the erosion of the deposited filtercake is a function of the shear stress at the formation wall, the mud filtercake thickness during circulation is likely to be larger at the narrow side of the annulus. The resultant nonuniform thickness of the filtercake would favor an uneven distribution of the flow path around the annulus and would further reduce the velocity of the fluid on the narrow side. In extreme cases, the fluid could stop flowing, be subjected to static filtration, and become very difficult to mobilize later.

When in contact with cement, a mud filtercake can further dehydrate and, in the same way as gelled mud, leave an empty space. However, a major difference is that mud filtercakes do not tend to form in front of impermeable caprock layers, where zonal isolation is especially important. Thus, the potential zonal isolation problems associated with mud filtercakes are often less critical than other types of problems such as differential sticking.

Mud filtercakes are very compressible; as a result, their mechanical properties vary widely. Close to the formation wall, yield stresses are typically a few hundreds of pascals for oil-base muds (OBMs) and 10 to 1,000 times more for water-base muds (WBM) (Cerasi et al., 2001). The outer part of the filtercake is more like gelled mud (Fig. 5-17). In other words, mud filtercakes can be consolidated. Ravi et al. (1992) called this layer “partially dehydrated gelled drilling fluid.”

The thickness of the mud filtercake is strongly dependent on the shear history. When circulation stops, a static filtercake grows. The filtercake is partly eroded when circulation and pipe movement resume. With time, the filtercake’s resistance to flow and the ratio of filtercake thickness to its mean permeability (known as hydraulic resistance) tend to increase; therefore, the rate of filtercake growth decreases during subsequent
static periods. Mud-filtercake thicknesses measured in the laboratory vary from a few millimeters to more than 1 cm (Haut and Crook, 1979).

The mud composition and chemistry strongly influence the cohesion of the mud filtercake and its adhesion to the rock surface (Amanullah, 2002). Cohesion and adhesion are key properties for mud-filtercake removal by backflow during completion operations (Ali et al., 1999). In this context, cohesion is the resistance of the filtercake in tension, while adhesion is the filtercake’s ability to stick to formation wall. During backflow, high adhesion and low cohesion will favor the creation of pinholes, while high cohesion and low adhesion will lead to peeling of the cake (Table 5-3).

The shear stress at the formation wall that corresponds to the high yield stresses mentioned above is unattainable under normal flow conditions. For example, achieving a wall shear stress of 250 Pa in a 1-cm-wide rectangular slot requires a pressure gradient of 1.1 psi/ft [25 kPa/m]. Thus, except for the outer layers, pure shear stress is not an efficient way to remove mud filtercake. This is well supported by experimental observations (Zuiderwijk, 1974; Crook et al., 1987).

5-2.4.6.3 Solids beds
Solids beds are the result of incomplete cuttings cleaning or weighting-agent settling. Thus, solids beds are often found in deviated and horizontal sections. Their

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**Table 5-3. Summary of Cleaning Mechanisms for Mudcakes and Solids Beds**

<table>
<thead>
<tr>
<th>Mechanism</th>
<th>Relevant Physical Parameters</th>
<th>Domain of Application</th>
</tr>
</thead>
<tbody>
<tr>
<td>Erosion by shear instability of interface</td>
<td>Wall shear stress, Shear strength</td>
<td>Mud circulation and displacement</td>
</tr>
<tr>
<td>Erosion by pressure fluctuations, rupture in tension</td>
<td>Reynolds number, Cohesion</td>
<td>Mud circulation and displacement</td>
</tr>
<tr>
<td>Pinholing or peeling</td>
<td>Differential pressure, Cohesion and adhesion</td>
<td>Backflow during completion operations</td>
</tr>
<tr>
<td>Weakening of layer mechanical properties, dissolution</td>
<td>Chemical composition, duration of treatment, Cohesion, shear strength, chemical nature</td>
<td>Completion operations, mud displacement</td>
</tr>
<tr>
<td>Fluidization, increase in lift force</td>
<td>Pressure gradient, Permeability, buoyant density of particles</td>
<td>Hole cleaning</td>
</tr>
<tr>
<td>Abrasion by suspended particles</td>
<td>Inertia of particles, Cohesion</td>
<td>Gravel-pack placement, Cutting transport and corresponding hole cleaning</td>
</tr>
</tbody>
</table>
occurrence is independent of formation properties and tubulars. Solids-bed removal is critical to the successful placement of casing on the bottom of the well. Its effect on local zonal isolation is not well understood, although one may expect it to be similar to that of a mud filtercake. The fact that solids beds occur over long intervals makes their presence potentially more detrimental than mud filtercakes.

The properties of solids beds have not been described quantitatively. Barite beds are known to be very cohesive and adhesive. Following laboratory tests, Bern et al. (1998) found barite beds to be very different from cuttings beds. Barite beds can be readily dispersed with a combination of high flow rates and drillpipe rotation. The presence of polymers in the drilling fluid increases the consolidation of solids beds (Saasen, 1998).

5-2.4.6.4 Removal of mud filtercakes and solids beds

Removal methods for mud filtercakes or solids beds are analogous to other engineering domains such as “cleaning-in-place” in the food industry, “back-pulse cleaning” in chemical engineering, or beach erosion in marine geophysics. Fluid velocities and contact time are critical parameters.

It is still unknown whether the shear stress at the wall or the Reynolds number is the key parameter (Plett, 1985). If the wall shear stress is the relevant physical parameter, the removal mechanisms are more likely to involve shear instabilities at the fluid/solids-bed interface. If the Reynolds number predominates, then pressure and stress fluctuations would be expected to play the major role. All of these effects are grouped under the general term “erosion.” This lack of basic knowledge is a root cause of the debate about whether viscous or dense fluids are more effective at cleaning wells (Sewell and Billingsley, 2002).

Abrasion is another process that is based on the inertial energy of solids particles carried by the flowing fluid. Upon impact with the solid layer, the particles can break some part of it. Johnson et al. (1992) and Becker and Gardiner (2000) observed this effect during flow loop tests of gravel placement. This is similar to a sand-blasting effect. Abrasion can also be achieved by scratchers fastened around the casing or by fluid jets directed perpendicular to the solid layer.

Solids beds are permeable; therefore, some flow may take place through them. Such flow may weaken the bed through a fluidization mechanism and increase the lift force on individual particles (Cho et al., 2001).

Finally, chemical or physico-chemical effects can lead to solids removal. The various phenomena include interfacial-tension reduction, weakening (cohesion or shear strength), dissolution of solid components, and degradation of polymeric components (Ryan et al., 1995). Chemicals that can cause such effects include acids, chelating agents, surfactants, dispersants, and oxidizers. The various filtercake and solids-removal mechanisms are summarized in Table 5-3.

During mud circulation, erosion is the only relevant solids-removal mechanism. Eventually, detached solids may induce some limited abrasion. Chemical effects later come into play when spacers and washes are pumped into the annulus. Such effects are discussed later in this chapter.

From the preceding discussion, it is clear that a complete understanding of the effects of mud gelation, mud filtration, and solids settling has not yet been achieved. Nevertheless, a qualitative analysis shows that all three may have a detrimental effect on circulation efficiency, in particular when the pipe is not centered. The global cleaning process is usually a series of steps. Optimization consists of selecting the correct order. This issue will be discussed in Section 5-5.

5-2.4.7 Measuring mud-circulation efficiency in the field

Traditions such as “circulating bottoms up” are often relied upon when designing the mud-circulation period before cementing. Results show that this approach is insufficient for complete mud removal in most circumstances. A better approach is to measure the mud-circulation efficiency (Smith, 1984). This is performed by monitoring the volume of mud that is actually circulating (the circulatable mud) with a fluid caliper or tracer. A small volume of mud is tagged with a tracer and injected at the wellhead. The time necessary for the tracer to return to the surface indicates the volume of mud being circulated. This volume is then compared to the borehole volume determined from caliper measurements. An illustration of this concept is shown in Fig. 5-18.

Tracers have included inert particles (oats, rice hulls), dyes (hematite, fluorescein), radioactive materials (scandium), chemical tracers (bromide, iodine, thiocyanate, nitrate) and reactive materials (carbide pills). Carbide pills are composed of calcium carbide. When added to the drilling mud, they dissolve in water and generate acetylene.

Detection of the tracer can be visual (dyes or particles retrieved on the shaker screen) or chemical (e.g., by using gas detectors, titration kits, ion-selective electrodes, and ion chromatographs) (Hall and Hughes, 1993). Most of these techniques only provide qualitative results, because it is often not clear what is being measured—time of first appearance or time of maximum tracer concentration. A quantitative analysis would
require continuous monitoring of the tracer concentration at the return line and an interpretation scheme to infer an average circulation velocity.

Nevertheless, these techniques are quite useful. For example, using carbide pills, Smith (1990) advocated designing the flow rate and the circulation time on the assumption that 95% of the calipered hole volume was circulating. His measurements (Fig. 5-19) led him to recommend circulation velocities in excess of 250 ft/min [76.2 m/min]. Such a velocity is quite high by oilfield standards.

Indirect methods based on surface or downhole pressure measurement provide indications of hole cleaning and cutting suspension. Ravi et al. (1993) and Griffith and Ravi (1995) performed surface pressure measurements that, when combined with continuous measurement of fluid rheology, density, and flow rate, allowed them to determine a pseudodispacement efficiency. Hutchinson and Rezmer-Cooper (1998) showed that annular pressure-while-drilling data can be interpreted in terms of hole cleaning and mud-solids carrying capacity. They also demonstrated the effectiveness of pipe rotation (Fig. 5-20).

Fig. 5-18. Left: Schematic of a well showing the fluid-caliper concept used to determine mud-circulation efficiency (from Smith, 1990). Right: Lithium-ion chemical log for tracer test: lithium bromide concentration in mud filtrate (mol/L mud) plotted against elapsed time (from Hall and Hughes, 1993). Reprinted with permission of SPE.

Fig. 5-19. Effect of annular velocity on circulation efficiency (from Smith, 1990). Reprinted with permission of SPE.
5-2.5 Mud circulation—conclusions

Ensuring that a large percentage of the mud is actually in circulation is a key to the success of a primary cement job. In view of the complexity of the problem, there is no doubt that sufficient time should be devoted to the design, execution, and evaluation of the mud conditioning and circulation stages before cementing. The following qualitative guidelines can be distilled from the preceding discussion.

- The rheological properties of the mud (namely the \( \mu_p/\tau_y \) ratio), mud gel strength, and pipe standoff should be such that the mud is moving completely around the annulus at an achievable flow rate. This can be done by improving pipe standoff, increasing the \( \mu_p/\tau_y \) ratio, decreasing the mud gel strength, or increasing the flow rate.

- If the above criteria for rheology, gel strength, and pipe standoff cannot be met, reciprocation or rotation of the pipe should be performed during mud circulation.

- When available, circulation models should be used to better optimize the above parameters in view of improving the circulation efficiency.

- The volume of circulated mud should represent at least one full hole volume; however, circulation models can be used to obtain a better estimate of the required mud circulation time.

- Whenever predictions are doubtful, fluid calipers should be used to measure the efficiency of the circulation process. Circulation should be maintained until the caliper indicates that 90% of the borehole volume is in circulation.

- The borehole pressure should be maintained between the pore and fracture pressures.

- To prevent the erosion of unconsolidated formation, it is a current practice to keep the annular velocity of the mud below the maximum value encountered during drilling.

- It is preferable to drill the hole with high-quality mud from the start. If poor-quality mud is used, it may be impossible to fully remove it before the cement job.

5-3 Mud displacement

Determining mud-displacement efficiency is more complex than determining mud-circulation efficiency. The interface profile between two dissimilar fluids is very different from the velocity profile of a single fluid flowing in the same geometry at the same flow rate (Fig. 5-1). However, the tendency to use the velocity profile to explain displacement efficiency still persists. In addition to the parameters mentioned earlier, mud displacement depends upon the relative properties of the fluids involved (density and rheology), their relative flow regimes, and their eventual interactions when mixed.
To introduce the subject, the origin of current field practices is summarized. Next, the physical description of the problem is presented. Phenomena that are understood best are described first, followed by those that are more complex and qualitative. This is followed by a discussion of laminar flow and turbulent-flow displacement of one fluid by another in concentric and eccentric annuli. Then, complicating situations such as gelled mud, solids layers, and casing movement are covered.

5-3.1 Field practices and observations

One of the first parameters recognized to influence mud-displacement efficiency was the flow regime of the displacing fluid. From pilot-scale studies, Howard and Clark (1948) concluded that, when the Reynolds number of the cement slurry was low, only 60% of the “circulatable” mud was displaced, whereas 90% to 95% could be displaced when the cement slurry was in the upper laminar flow or turbulent-flow regime. In 1964, Brice and Holmes surveyed 46 cement jobs performed in southwest Louisiana, an area that was experiencing primary cementing failures. They reiterated the need for turbulent flow, and suggested that the annular space should be in contact with a turbulent displacing fluid for a sufficient time. Subsequent pilot-scale studies lead to the establishment of rules, called good cementing practices, to maximize mud removal (Table 5-4). Today, these practices are generally accepted in the industry. Numerous case studies have demonstrated their effectiveness in many situations. However, these practices remain qualitative because no accepted thresholds or recommended values are provided.

More recently, quantitative rules were developed from improved knowledge or more experiments (Brady et al., 1992; Ryan et al., 1992). Density hierarchy, viscosity hierarchy, and minimum pressure gradient are now part of the design criteria to optimize mud displacement. The quantitative requirements attached to these rules were derived from simple physical reasoning, pilot experiments, or field observations and were confirmed by field studies (Kelessidis et al., 1995). Increased modeling capabilities and understanding have allowed the industry to test designs that more closely resemble field reality (Tehrani et al., 1992; Bittleston et al., 2002).

5-3.2 Problem description

Efficient displacement of one fluid by another results from the interplay between various forces. Some forces aid displacement, while others inhibit it. These forces include buoyancy, viscosity, inertia, and other rheological properties such as yield stress and gel strength. Physico-chemical effects must also be considered; however, these are more difficult to include in global models.

These forces are closely related to various parameters. For example, buoyancy forces are a direct function of density differences and hole inclination, while viscous forces are functions of fluid rheology, wellbore geometry, and flow conditions. In general, mud displacement is a competition between driving and resisting forces. The predominant driving or resisting force will depend upon the local conditions.

- In a large vertical annulus, with a heavy fluid displacing a lighter one at slow velocity, buoyancy forces will be the main driving force.
- Conversely, in a deviated and slim annulus, viscous forces will generally govern the flow.

Because each type of force has a different dependence on length, the mechanisms driving the displacement are a function of the length scale.

Table 5-4. Good Cementing Practices†

<table>
<thead>
<tr>
<th>Wellbore geometry</th>
<th>The ideal annulus is straight, free of washouts, and at least 1.5 in. wide.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Centralization</td>
<td>The casing is kept as near the middle of the wellbore as possible. A standoff of about 75% is generally considered to be acceptable.</td>
</tr>
<tr>
<td>Mud conditioning</td>
<td>The mud is circulated before the cementation to remove gas and cuttings, break the mud’s gel strength, and lower the mud’s viscosity.</td>
</tr>
<tr>
<td>Casing movement</td>
<td>Rotation is preferred to reciprocation. Movement should start during mud conditioning.</td>
</tr>
<tr>
<td>Chemical washes and spacers</td>
<td>Washers and spacers are pumped ahead of the slurry, acting as a buffer between possibly incompatible mud and cement. A 10-min contact time is recommended.</td>
</tr>
<tr>
<td>Cementing plugs</td>
<td>Top and bottom plugs are pumped ahead and behind the slurry to separate it from the mud.</td>
</tr>
<tr>
<td>Other casing hardware</td>
<td>Scratchers are sometimes attached to the outside of the casing to remove the mud filtercake.</td>
</tr>
</tbody>
</table>

On a large length scale, typically the length of the interval being treated, various displacement patterns occur, e.g., plug flow. This is the domain of fluid mechanics, both theoretical and experimental.

On a small length scale, typically the thickness of the annular gap, mud filtercakes, immiscible fluids, and other physico-chemical phenomena predominate.

A typical order of magnitude for the ratio of these two length scales is $10^4$. As previously mentioned, no laboratory apparatus can be scaled to simultaneously reproduce field conditions and consider all of the independent variables.

The present understanding of the influence of these forces on mud displacement is incomplete. On a small scale, the general term erosion is frequently used to cover poorly known phenomena. Large-scale phenomena are somewhat better understood.

Everything else being equal and at low flow rates, the upward displacement of a dense fluid by a lighter one in a vertical conduit leads to an unstable phenomenon known as a buoyant plume. Conversely, when the displacing fluid is heavier than the displaced fluid, buoyancy forces tend to flatten the interface and promote efficient displacement. Similarly, the displacement of a viscous fluid by a less viscous fluid of identical density leads to viscous fingering, in which a stream of the less viscous fluid penetrates the interface and enters the more viscous fluid. Conversely, displacing a thin fluid by a more viscous one leads to better displacement. More complex combinations of density, rheology, and borehole geometry remain a subject of academic research.

Modeling large-scale displacement relies on the use of fluid-mechanics laws (mass and momentum balance for each fluid) and consistent boundary conditions. Further, considering the large borehole-height/gap-thickness ratio, the problem is usually reduced to two dimensions by averaging physical quantities across the gap width. Alternatively, true 3D codes have been developed; however, the running time is on the order of days rather than minutes. Two different methods are employed to track the interface between two fluids: a mesh moving with the interface and a fixed virtual mesh with the concentration calculated for each fluid in each mesh cell.

5.3.3 Laminar displacement of mobile mud in concentric vertical annuli

In a vertical and centered annulus with favorable density and viscosity ratios, the displacement is stable in the azimuthal direction. Any variation in displacement efficiency is caused by the shape of the interface profile in the radial direction. Therefore, the problem is reduced to two dimensions, axial and radial coordinates.

A basic displacement-efficiency model for these conditions is built as follows. Consider a thin rectangular slot of width $L$, with static layers of displaced fluid along the walls and the displacing fluid flowing in the middle at a mean velocity, $\bar{v}$. The displacing fluid creates a shear stress. As long as this shear stress is less than the yield stress of the displaced fluid, the layers along the wall are stable and their maximum thicknesses can be determined. Although this seems simple, it is only recently that Allouche et al. (2000) provided an exact solution for two yield-stress fluids. They showed that this maximum thickness depends on only three parameters: the ratio of the yield stress of the two fluids, $R_y$; the Bingham number of the displacing fluid, $N_{BG}$; and the ratio of buoyancy forces to the yield stress, $R_b$ (Fig. 5-21). Four situations are possible, labeled (a) to (d) on Fig. 5-21, depending on the relative values of the shear strength of the two fluids with respect to the shear stress at the fluid interface.

$$R_y = \left( \frac{\tau_y}{\tau_1} \right)_2, \quad N_{BG} = \frac{\left( \frac{\tau_y}{\mu_2} \right)_2 L}{2 \left( \frac{\tau_y}{\mu_1} \right)_1 \bar{v}}, \quad R_b = \frac{(p_2 - p_1) g L}{2 \left( \frac{\tau_y}{\mu_1} \right)_1}$$

(5-8)

This model provides two predictions.

- The maximum possible displacement efficiency, i.e., the displacement efficiency when steady-state conditions are reached
- The conditions necessary to remove the static layer (as shown in Eq. 5-9, this condition is independent of the buoyancy ratio)

$$\left( \frac{\tau_y}{\mu_1} \right)_2 = \left( \frac{\tau_y}{\mu_1} \right)_{cem} = \left( \frac{\tau_y}{\mu_1} \right)_{mud} = \frac{1}{\xi}$$

(5-9)

with dimensionless shear rate, $\xi$, being the solution of $2\xi^3 - 2(3 + 6/N_{BG}) \xi^2 + 1 = 0$.

The main limitation of this work is that it neglects the displacement front.

Flumerfelt (1973) and Beirute and Flumerfelt (1977) presented the first complete 2D model that provides the time variation of the displacement efficiency. The main assumptions of these analyses are given below.

- Displacement takes place in a narrow rectangular and vertical slot with upward flow.
- For both fluids, the flow regime is laminar, and the Reynolds numbers of each fluid, $(N_{Re})$, are small compared to the length-to-gap ratio of the annulus, i.e.,

$$\left( \frac{N_{Re}}{d_o} \right)_i \ll \frac{Z}{d_o - d_w}$$
Displacement occurs under stable conditions (i.e., the interface is smooth, a condition that is not quantitatively defined in the papers).

The fluids are miscible (i.e., interfacial tension is neglected).

Molecular diffusion at the interface is negligible.

The horizontal velocities are negligible.

The authors recognized that the mass balance was not correct. In addition to the dimensionless time, the approximate solution depends on five dimensionless parameters for power-law fluids (two more for fluids with a three-parameter rheological model such as Herschel-Bulkley): density ratio, effective viscosity ratio, dimensionless flow rate, and the two power-law indices. The principal conclusions of these works are given below.

- The density ratio plays a predominant role, provided the dimensionless flow rate is not too high. A density ratio greater than 1 flattens the profile of the interface and enhances the displacement efficiency (Fig. 5-22).
- Although the displacement efficiencies increase with increasing effective viscosity ratios, their effect is less important than that of the density ratio (Fig. 5-22).
- Power-law indices do not seem to be important in the case of Herschel-Bulkley fluids. For power-law fluids, better displacement efficiencies are obtained when the power-law index of the displacing fluid is lower than that of the displaced fluid.
- In the case of Herschel-Bulkley fluids, yield stresses are critical. High displacement efficiencies result when the dimensionless yield stress values of the displacing fluid are higher than those of the displaced fluid.
- For fluids with a nonzero yield stress, displacement efficiencies decrease with increasing dimensionless flow rates.

When looking carefully at the data presented in both papers, it appears that the last conclusion is somehow too drastic. For example, in the case of power-law fluids, Flumerfelt (1973) varied the power-law indices while keeping the other dimensionless parameters constant (Table 5-5). The ratio of apparent viscosities of the two fluids (calculated at the wall for both fluids as if they were pumped independently) changed greatly. Also, depending on the relative value of the power-law indices, this ratio could increase or decrease with increasing flow rate, leading to an improvement or a deterioration of the displacement efficiency. More specifically, the displacement efficiency decreases with flow rate when the ratio of apparent viscosities is less than unity (stable situation), and it increases in the unstable situation (apparent viscosity ratios higher than unity). The same argument applies to the effect of yield stresses for Herschel-Bulkley fluids.
**Fig. 5-22.** Effect of density ratio (noted as $R_2$) and effective viscosity ratio (noted as $R_3$) on displacement efficiency versus time (after Beirute and Flumerfelt, 1977). Reprinted with permission of SPE.

**Table 5-5. Effect of Dimensionless Flow Rate ($R_4$) on Displacement Efficiency†**

<table>
<thead>
<tr>
<th>Circulation Efficiencies for $n_1 = 1, n_2 = 1$ (Newtonian Fluids)</th>
<th>Effective Viscosity Ratio ($R_3$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$R_4$</td>
<td>$t^* = 1$</td>
</tr>
<tr>
<td>$10^{-4}$</td>
<td>0.808</td>
</tr>
<tr>
<td>$10^{-3}$</td>
<td>0.808</td>
</tr>
<tr>
<td>$10^{-2}$</td>
<td>0.808</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Circulation Efficiencies for $n_1 = 1, n_2 = 0.6$ (Stable Conditions)</th>
<th>Effective Viscosity Ratio ($R_3$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$R_4$</td>
<td>$t^* = 1$</td>
</tr>
<tr>
<td>$10^{-4}$</td>
<td>0.937</td>
</tr>
<tr>
<td>$10^{-3}$</td>
<td>0.926</td>
</tr>
<tr>
<td>$10^{-2}$</td>
<td>0.901</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Circulation Efficiencies for $n_1 = 0.6, n_2 = 1$ (Unstable Conditions)</th>
<th>Effective Viscosity Ratio ($R_3$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$R_4$</td>
<td>$t^* = 1$</td>
</tr>
<tr>
<td>$10^{-4}$</td>
<td>0.467</td>
</tr>
<tr>
<td>$10^{-3}$</td>
<td>0.568</td>
</tr>
<tr>
<td>$10^{-2}$</td>
<td>0.672</td>
</tr>
</tbody>
</table>

† In this table, density ratio = 1. The column on the right gives the ratio of apparent viscosities of the fluids when pumped individually. All dimensionless ratios represent displacing to displaced fluid.
These theoretical developments regarding the displacement process in a concentric annulus have emphasized the role played by gravitational and viscous forces. With the density ratio and the low shear-viscosity ratio higher than 1 (i.e., power-law index ratio lower than 1 and a yield-stress ratio higher than one for fluids exhibiting a yield stress), low flow rates contribute to a flattening of the interface profile and lead to efficient displacement. With increasing flow rate, the influence of the density ratio logically decreases, and the viscous properties continue to have an impact. Everything else being equal, the more viscous the displacing fluid, the better the results. However, care should be taken to compare apparent fluid viscosities in a shear-rate range representative of the flow conditions to be encountered.

Similar conclusions on the effect of viscosity can be deduced from the work of Nguyen et al. (1992), who studied the displacement of a power-law fluid by another power-law fluid in a concentric and horizontal annulus, assuming uniform azimuthal pressures. This assumption allowed them to use a 2D model. They presented their result in terms of the thickness of the displaced-fluid layer remaining on the wall. At a given time, varying only the ratio of fluid consistencies has a significant effect on the thickness of the wall layer.

### 5.3.3.1 Experimental validation

Most of the experimental studies performed on laminar flow displacement in concentric annuli (Childers, 1968; Zuiderwijk, 1974) are in qualitative agreement with the theoretical study presented above, as far as the relative importance of fluid properties (density and rheology) and flow rates is concerned. One of the most extensive studies is that of Zuiderwijk (1974), who performed more than 200 tests. Muds were displaced by five annular volumes of cement, and displacement efficiencies greater than 80% were observed. All fluids were assumed to follow the power-law model. Zuiderwijk (1974) concluded that annular velocity is a key parameter in the displacement process. The results showed that, at low velocities, a density ratio greater than 1 enhanced the displacement efficiency, and gravitational forces appeared to be less important for velocities higher than 1 ft/s [0.3 m/s]. Depending on the prevailing conditions, efficient displacement was obtained at both low and high displacement rates. At low velocities, good results were obtained with cement slurries having a higher viscosity than the mud (power-law index ratio \( n_{\text{cement}} / n_{\text{mud}} < 1 \)). Well-treated muds (i.e., muds with a low yield point) were also easily removed from washout sections when displaced by a very thin cement slurry at high velocities (in which case \( n_{\text{cement}} / n_{\text{mud}} > 1 \)), and the efficiency of the process was attributed to the turbulent eddies in the displacing fluid (this point is discussed later). For velocities ranging from 0.5 to 1.5 ft/sec [0.15 to 0.46 m/s] and values of \( n_{\text{cement}} / n_{\text{mud}} \) on the order of 1, the displacement efficiency was almost constant.

The slow-flow technique, which was developed in the 1960s to overcome some of the practical limitations of turbulent flow displacement, also relies on experimental observations that are partially in agreement with the Beirute and Flumerfelt (1977) studies. Parker et al. (1965) showed that good mud displacement could be obtained at low flow rates, provided the displacing fluid (a cement slurry in this case) is at least 2 lbm/gal [0.24 g/cm³] heavier than the mud and the initial gel strength and viscosity of the mud are less than those of the cement slurry. They also observed that, under these conditions, the displacement efficiency deteriorated with increasing flow rate. For good mud displacement, the shear stress applied by the displacing fluid should be higher than the gel strength of the mud.

Excellent results were obtained in the presence of washouts when the annular velocity was less than 90 ft/min [27 m/min]. The efficiency of the process was attributed to the action of a coagulated mass at the cement/mud interface, which provided a piston-like displacement even in large washouts and irregularities. At higher flow rates, the cement slurry broke through this gel mass; consequently, poor displacement efficiencies resulted. However, the results available did not allow the clear definition of an optimal displacement velocity range (Fig. 5-23).

The slow-flow technique was later refined. The combined effect of density and gel strength differential on mud-displacement efficiency was evaluated and, in the most common case in which the mud density was lower than that of the cement, the minimum gel strength required for 100% mud displacement could be calculated empirically (Fig. 5-24). Parket et al. made a qualitative conclusion that “a sufficiently high-density ratio can compensate for an unfavorable yield-stress ratio.”

These experimental results provide only a qualitative indication concerning the efficiency of the displacement process. The measurements do not allow one to quantitatively validate the efficiencies predicted by the numerical displacement models. A common conclusion of both the numerical models and the experiments is that a favorable density ratio can compensate for an unfavorable effective viscosity ratio, bearing in mind that the effective viscosity ratio is flow rate-dependent.
5-3.4 Modeling of mud removal in eccentric annuli

Until now, the mud-removal discussion has been confined to concentric annuli. As discussed earlier, eccentric annuli are encountered in most cement jobs, and many cementing difficulties are exacerbated by casing eccentricity and geometrical asymmetry (e.g., in dual completions). The main difference with respect to a centered annulus is that the problem is now truly 3D. The displacement fluid may channel in both the radial and azimuthal directions.

The most common way to model displacement in an eccentric annulus is to use the parallel-slot analogy or the sectored concentric-annulus analogy, described in Chapter 4 (Section 4-6.3). The three principal limitations to this approach are as follows.

- The validity of the results strongly degrades when the radius ratio is far from unity.
- The drag stress between consecutive sectors or slots is ignored.
- The pressure is assumed to be uniform in any cross-section.

This model is intrinsically one-dimensional (1D), but it leads to some semiquantitative criteria that are useful for job design. The job-design restrictions imposed by the above limitations will be described later.

Jones and Berdine (1940) and Howard and Clark (1948) described the channeling of the displacing fluid on the wide side of the annulus. In 1967, McLean et al. described a more fundamental effort to understand the role of casing eccentricity on mud removal. First, they developed a 1D model describing the flow of a single Bingham plastic fluid in an eccentric annulus, based on the sectored concentric-annulus analogy. Next, the model was extended to the displacement problem in the absence of gravitational forces. The results suggested that, in laminar flow, displacements in eccentric annuli are more effectively optimized by increasing the yield-stress ratio rather than the plastic-viscosity ratio. The reasons for this are twofold.

1. Once the yield-stress ratio is higher than a critical value equal to

\[
\frac{2 - R_{STO}}{R_{STO}}
\]

the shear stresses generated by the cement are sufficiently high for the mud to flow in the narrowest part of the annulus. Under creeping flow conditions (i.e., near-zero flow rate), the velocity of the mud in the narrowest part of the annulus is equal to the average velocity of the displacing fluid. In effect, there is 100% displacement efficiency. As the flow rate increases, the displacement efficiency decreases (Fig. 5-25).

2. Increasing the plastic viscosity ratio improves the displacement efficiency. This effect is stronger as the flow rate is higher (Fig. 5-26).

Both points can be qualitatively understood by considering the effective viscosity of a Bingham fluid, \( \mu_{eff} = \mu_p + \tau_y/\dot{\gamma} \). Increasing the flow rate, hence the shear rate, decreases the importance of the yield stress with respect to the plastic viscosity. Point 1, however, seems paradoxical. Under creeping-flow conditions, the
cement-slurry velocity in the narrow side of the annulus should be zero, because the yield stress of the cement slurry is much higher than that of the mud. This is effectively what McLean et al. (1967) observed; however, this did not prevent the mud from being driven by the cement from the narrow side to the wide side. Although Point 2 is logical, the authors presented little data to support it. The limited number of tests they performed with density differences tend to show that gravitational forces do play a role on mud displacement in an eccentric annulus.

McLean et al. (1967) also investigated displacement at high flow rates in the extended transition from laminar to turbulent flow but using extremely severe conditions (with the inner pipe lying against the outer pipe). Under these circumstances, when displacing a mud or a cement slurry exhibiting a yield stress, better results were obtained with a high-viscosity displacing fluid in laminar flow than a low-viscosity fluid in partial turbulent flow. These experiments were performed at the same flow rate and, in both cases, the displacement efficiency increased with the flow rate. On the basis of their theoretical work and limited experimental studies (they intentionally did not allow the muds to gel), McLean et al. (1967) suggested that viscous displacing fluids are better at achieving high displacement efficiency than thin fluids. While thin displacing fluids extend the area of turbulent flow, the drag and pressure gradient are significantly reduced.

Other authors have attempted to model the effect of eccentricity on the displacement process. On the basis of the same annular geometry used by McLean et al. (1967), Graham (1972) modeled the fluids as a 1D bundle of parallel cylindrical pipes. He reemphasized the relative-viscosity concept in the absence of gravitational forces, and used a mobility ratio concept defined as the ratio of the flow rate to the friction pressure. A mobility ratio greater than 1 was shown to be desirable for optimal displacement. Because different fluids exhibit different changes in mobility with changing flow conditions, optimum results could be obtained at either high or low flow rates. Even under the best conditions, the velocity of the interface was always greater in the wide part of the annulus than in the narrow side (Fig. 5-27). To overcome the resulting difference in the level of the interface and to ensure that cement would reach the target level on the narrow side, Graham (1972) applied the knowledge of the interfacial velocity around the annulus and proposed pumping an excess volume of cement slurry.

Graham’s theoretical developments led him to draw completely different conclusions from those of McLean et al. (1967). Muds with low yield points and low plastic viscosities, displaced at the highest possible rate by viscous cement slurries, were recommended. Specific conditions were imposed on the mud rheology: \(\tau_y < 5 \text{lbf/100 ft}^2\) and \(\mu_p < 12 \text{cp}\). Although the effects of density differences were not included in this analysis, Graham recommended relying more on viscous forces—hence high rates and low yield points—than density differences. In most practical situations, the density difference is favorable; thus, Graham’s conclusions are conservative.

Jamot (1974) extended Graham’s model by introducing the effect of gravitational forces. He found that the deformation of the fluid interface caused by eccentricity was minimized at low displacement rates. The best results were obtained when the density of the mud was significantly lower than that of the displacing fluid (typically \(> 4.2 \text{lbm/gal} [500 \text{ kg/m}^3]\)). Care was taken to minimize the gel strength of the mud and to use viscous displacing fluids. On the other hand, turbulent flow was
more effective when the density differences were small (typically <1.7 lbm/gal [0.2 g/cm³]). In between, both flow regimes showed equivalent efficiencies, and laminar flow gave the poorest results in all cases (Fig. 5-28).

**Fig. 5-27.** Effect of flow rate on displacement of a mud by a cement slurry from an eccentric annulus (from Graham, 1972). Reprinted with permission from Oil & Gas Journal.

**Fig. 5-28.** Effect of flow rate and flow regime on the displacement of muds of various densities by a cement in an eccentric annulus (standoff = 80%) (Jamot, 1974).

Ryan et al. (1992) describe the use of a similar model implemented into a simulator for field use.

An advance in the modeling was presented by Martin et al. (1978). They considered the flow as 2D, the values of all parameters being averaged along directions perpendicular to the cylindrical surfaces. The flow equations were solved by making an analogy with those governing the flow of two immiscible fluids in porous media. Jamot’s (1974) recommendations regarding the optimum flow regime and density ratio were largely confirmed. Martin et al. claimed that the density and viscosity ratios had a similar effect, but this statement was purely qualitative.

Unlike previous studies, Martin et al. (1978) investigated the displacement of a given fluid by two others (e.g., a spacer fluid and a cement slurry). Their model demonstrated that, at low displacement rates, a spacer could have a negligible or even a negative effect on mud displacement. They assumed the fluids were separated by sharp interfaces, with no mixing zones or possible chemical interactions. The results showed that, to be effective, the density and rheology of the spacer fluid must be between those of the mud and cement, especially for smaller standoffs. When outside this range, the spacer would tend to flow preferentially on the wide side. In extreme cases, the flow was confined to either the wide side or the narrow side of the annulus; consequently, the cement slurry would directly contact the mud.

Tehrani et al. (1992) presented results from a numerical model close to that of Martin et al. (1978), together with experiments that validated the model. This model was further refined by Bittleston et al. (2002): The azimuthal-flow simulation was improved, and a lubrication assumption was used in the radial direction. This allowed more realistic simulations of displacement in horizontal sections. The focus was to understand the fluid behavior close to the displacement front. In particular, significant azimuthal flows that aid displacement were observed in the vicinity of the front. This feature is reminiscent of similar observation by Szabo and Hassager (1997).

Allouche et al. (2000) developed a model that simulates displacement in the axial-radial direction to complement the Bittleston et al. model. The model shows that complex flow takes place at the displacement front, with recirculation loops that correlate with the presence of a static layer of undisplaced fluid (Fig. 5-29).

This flow makes the basic axial-displacement model described by McLean et al. (1967) largely conservative; in fact, precise numerical simulations showed that the actual static-layer thickness is less than the maximum value (Fig. 5-30). Allouche et al. (2000) argued that the layer thickness is better predicted by using a calculation...
based on energy dissipation than by comparing the shear stress of the flowing fluid with the yield stress of the immobile fluid.

Ladva et al. (2001) showed typical displacement patterns that arise depending on the principal forces described in Section 5-3.2 (Fig. 5-31).

1. Stable or piston-like displacements are obtained when the combination of buoyant and viscous forces is sufficient to overcome the destabilizing effects of standoff and viscous fingering. 
2. When viscous fingering occurs, a mud channel is formed. The mud velocity in the channel may be such that the channel eventually disappears once enough displacing fluid has been pumped. 
3. In cases in which the yield stress of the mud is large, buoyant and viscous forces are insufficient to break the gelled mud, and the mud channel is truly static. 
4. Finally, gravity instabilities (reminiscent of Rayleigh-Taylor instabilities) may appear when the buoyant forces are large and unfavorable. Such instabilities occur when a dense fluid is placed on top of a light fluid, with viscosity dampening the exchange flow. This last pattern is often observed when low-viscosity and low-density washes are pumped in turbulent flow. 

These results show that good modeling of azimuthal flow is necessary to capture the effect of azimuthal velocity components, especially in the displacement front region between each pair of fluids. Note how the velocity field is complex around the fluid interfaces, even for piston displacement. This means that, locally, there are large azimuthal velocities. Only a correct account of these azimuthal velocities can produce meaningful simulations.

Nguyen et al. (1992) and Nguyen and Rahman (2002) described a model specifically designed to simulate displacement in horizontal sections, first in concentric annuli, then in eccentric situations. However, the rheological model did not include a yield stress component, which restricts the use of this model.

As computing power increased, computational fluid dynamics (CFD) codes were used to model fluid displacement. Vefring et al. (1997) and Biezen et al. (2000) proposed using software that simulates the 3D flow of power-law fluids in an eccentric annulus. However, no details were provided on the computations, and few results were presented in terms of displacement efficiency. Such simulations are presently used to complement physical experiments. Various boundary conditions can be simulated, including casing rotation, but presently available computer power prevents general application of this approach.

Szabo and Hassager (1997) simulated the 3D displacement of two immiscible Newtonian fluids in a vertical annulus and provided detailed analyses of several interesting situations. For concentric annuli, starting from a circulation situation—for which the interface has a parabolic velocity profile, known as a Poiseuille shape—the interface shape becomes increasingly flat as

Fig. 5-29. Schematic illustration of the two types of streamline behavior at the displacement front: a) no recirculation in displaced fluid; b) with recirculation in displaced fluid (from Allouche et al. 2000). Copyright Cambridge University Press.

Fig. 5-30. Variation of layer thickness versus yield stress of displaced fluid. Points marked by a circle are experimental transient layers, while those marked by a cross are experimental static layers. The two lines correspond to the two different theoretical criteria (from Allouche et al., 2000). Copyright Cambridge University Press.
the fluid properties are varied and gravitational forces exceed viscous forces by increasing buoyancy and keeping the Reynolds number low. Eventually, the interface becomes steady. Consequently, buoyancy forces significantly improve the displacement efficiency by draining more of the displaced fluid film at the wall. They also observed that secondary flows appear on both sides of the interface. The displaced fluid from the wall region is moved toward the center and, behind the interface, displacing fluid from the center is moved towards the wall. For eccentric annuli, Szabo and Hassager observed that a sufficiently great density difference promotes azimuthal flow, thereby increasing the relative velocity in the narrow side. This effect seemed to make the displacement efficiency independent of eccentricity. From these results, Szabo and Hassager (1997) concluded that favorable density ratios improve fluid displacement in both the radial and azimuthal directions, provided the buoyancy number is large enough and the Reynolds number remains low.

CFD tools are also used for the related problem of hole cleaning (King et al., 2000); their use will continue to grow. Understanding the effects of combinations of density and viscosity differences remains a subject of academic research (Lajeunesse et al., 1999), as is investigation of cases in which the fluids are non-Newtonian and have the same density (Lindner et al., 2000). Thus, the industry does not have a good understanding of field conditions that combine non-Newtonian rheology, density differences, and nonuniform gap width (for eccentric annuli); however, recent work of Bittleston et al. (2002).
and Pelipenko and Frigaard (2004) provide directly useful results on the stability of mud channels in such conditions.

5-3.5 Laminar mud displacement criteria

Besides these computational models, Lockyear et al. (1989), Couturier et al. (1990), and Ryan et al. (1992) proposed various rules, based on the analysis of a 1D model, that can be routinely used. In short, these rules are based on an analysis of forces far from the displacement front. These authors’ key objective was to combine density and viscosity effects and define design criteria that would prevent or minimize mud channels, as well as ensure that potentially immobile mud on the narrow side is mobilized.

In a mud-channel situation, the fluids are flowing at different speeds. Couturier et al. (1990) defined a rule to prevent mud-channel growth. The velocity of the mud on the narrow side must be greater than or equal to the cement velocity on the wide side.

$$\frac{dp}{dz}_{f \text{- mud}} + (\rho_{\text{mud}} g \cos \theta) < \frac{dp}{dz}_{f \text{- cem}} + (\rho_{\text{cem}} g \cos \theta)$$

(5-10)

For the mud, the pressure gradient $\frac{dp}{dz}_{f \text{- mud}}$ assumes a slot width equal to the gap size on the narrow side of the annulus. For the cement, the slot width is equal to the gap size on the wide side.

According to Lockyear et al. (1989) and Couturier et al. (1990), static mud on the narrow side will be forced to move if the pressure exerted by the displacing fluid flowing on the large side creates a wall shear stress on the narrow side that exceeds the mud yield stress. This reasoning leads to the following expressions for the minimum pressure gradient $\frac{dp}{dz}_{f \text{- min}}$.

$$\frac{dp}{dz}_{f \text{- min}} = \frac{2(\tau_y)_{\text{mud}}}{L_{\text{min}} \left(1 - \frac{L_{\text{min}}}{d_o}\right)}$$

(5-11)

for Lockyear et al. (1989).

$$\frac{dp}{dz}_{f \text{- min}} = \frac{2(\tau_y)_{\text{mud}}}{L_{\text{min}}}$$

(5-12)

for Couturier et al. (1990).

Ryan et al. (1992) proposed another set of expressions that includes buoyancy effects, distinguishing the cases in which gravity forces are favorable from those in which they are not. For upward mud flow, Eqs. 5-13 and 5-14 show the necessary conditions.

If $\rho_{\text{mud}} < \rho_{\text{cem}}$, then:

$$\sqrt{\left[\frac{dp}{dz}\right]_f + D^2 + 2\left(\frac{dp}{dz}\right)_f D \cos \alpha} > \frac{\rho_{\text{cem}} g}{\rho_{\text{mud}}}$$

(5-13)

If $\rho_{\text{mud}} > \rho_{\text{cem}}$, then:

$$\frac{\left(\frac{dp}{dz}\right)_f + D \cos \alpha}{Y} > 1$$

(5-14)

Eq. 5-15 will lead to downward mud flow.

$$\frac{\left(\frac{dp}{dz}\right)_f + D \cos \alpha}{Y} < 1$$

(5-15)

In these expressions, $\frac{dp}{dz}_f$ is the pressure gradient, $D = (\rho_{\text{cem}} - \rho_{\text{mud}})g$, with $L_{\text{min}}$ being the minimum annular width. $Y$ is the yield force of the displaced fluid $2(\tau_y)_{\text{mud}}L_{\text{min}}$ and $\alpha$ the deviation angle. The ratio $(P + D \cos \alpha)/Y$ is called the displacement number.

Kroken et al. (1995) made an additional suggestion for horizontal sections. Under such conditions, the casing frequently lies along the bottom of the borehole wall. They recommended allowing the dense cement slurry (which usually channels on the top side of the annulus) to fall by gravity onto the narrow side, displacing the mud. For this situation to happen, the fluid velocities must be low enough for inertial forces to be less than buoyancy forces. This leads to the following relationship.

$$\frac{gd_o (\rho_{\text{cem}} - \rho_{\text{mud}})}{\rho_{\text{mud}} \bar{v}^2} > 1.$$  

(5-16)

In this equation, $d_o$ is the hole diameter and $\bar{v}$ is the fluid velocity. It is important to note that Kroken et al. (1995) assumed that the mud was not gelled. In this approach, fluid yield stresses are ignored. Therefore, this calculation cannot be used if the mud is gelled on the narrow side. This is confirmed by 2D numerical simulations using the Bittleston et al. (2002) model. Figure 5-32 shows that lowering the displacement rate enhances the displacement of the spacer (which has a low yield stress). As a result, a channel of static mud is left on the narrow side.

For horizontal wells, Jennings (1995) proposed using a pair of spacers and a pair of cement slurries. Each fluid pair consists of a high-density fluid followed by a low-
density fluid. The high-density fluid displaces the mud on the low side, while the lighter fluid fills channels remaining on the high side of the horizontal section.

To summarize this review of models and criteria, one can classify these models according to their complexity.

- One-dimensional models provide semiquantitative rules or criteria. They are limited to describing simple steady-state situations but have been successfully used for routine operations.

- Two-dimensional models provide a reasonable analysis of either axial-radial flow (e.g., predicting the size of the mud layer along the walls) or axial-azimuthal flow, i.e., mud channels. Early models suffered from various limiting assumptions that restricted their use to wells with limited deviation and relatively narrow annuli. In addition, the erosion of static layers was not modeled. The latest models do not suffer from these limitations and are the ideal tools to perform parametric studies combining all the relevant forces acting together.

- Three-dimensional models allow a good understanding of the various phenomena but, owing to their complexity, they remain research tools today. As available computational power continues to increase, such tools will eventually enter the mainstream.

5-3.6 Turbulent flow and erosion mechanisms

As discussed earlier, Howard and Clark (1948) achieved good mud-displacement efficiencies when using cement slurries in the upper-laminar and turbulent-flow regimes. Turbulent-flow displacement became commonplace in the 1960s, with the introduction of cement dispersants that allowed turbulence at achievable pump rates (Chapter 3). In 1964, Brice and Holmes reiterated the need for turbulent flow and suggested that the annular space should be in contact with the turbulent displacing fluid for a sufficient time. However, it is difficult to define an optimum contact time from their data (Fig. 5-19).

Since then, some engineers have claimed that a 4-min contact time is sufficient, while others claim a 10-min interval is necessary. From the Brice and Holmes data (1964), 8 min appears to be a reasonable guideline; however, such an assumption would ignore other important factors such as casing movement and centralization. The turbulent-flow displacement technique has since gained wide acceptance, because it has greatly increased the success rate of cement jobs in many areas. For instance, Raymondeau et al. (1991) reported excellent results when the preflushes and the cement slurry were pumped at rates that ensured turbulent flow all around the eccentered annulus. For these jobs, the minimum contact time was set at 5 min.

Today, there is a clear agreement that low-viscosity, low-density fluids such as water, diesel oil, or a chemical wash effectively remove mud, provided certain conditions are met. Terms such as erosion, drag, mixing, or dilution are used to explain the underlying mechanisms. Actually, the fundamentals behind this practice are not well understood. Clearly, turbulent flow alone is not sufficient. In pilot-scale experiments, replacing a viscous fluid flowing in laminar flow by a thin fluid pumped at the same rate usually leads to a sharp pressure-gradient decrease. However, displacing a laminar fluid by a turbulent fluid at an equal friction-pressure drop will lead to better cleaning (Clark and Carter, 1973). Note that shear stresses generated by unweighted fluids even at very high Reynolds numbers are lower than those of viscous spacers pumped at the same conditions. Table 5-6 shows, for different annular sizes and rates, the Reynolds numbers, friction pressures, and wall shear stresses for water, oil, chemical washes, and weighted spacers.

Hence, the conditions for efficient turbulent flow are more difficult to understand than those for laminar flow. Mechanisms other than the simple hydrodynamic forces considered above are at play. Some of them are detailed in Section 5-2.4.6. In this section, three types of static materials are distinguished: gelled mud, mud filtercake, and solids layers. Their properties differ widely, and they can be found in different parts of the annulus. Thus, different mechanisms may be required to remove them.
Several experimental observations have been described that help explain the basic cleaning mechanisms.

- **Gravity instabilities**
  Lockyear et al. (1989) observed the behavior of a heavy fluid on the narrow side of the annulus being bypassed by a lighter fluid. The heavy fluid slumped down and moved toward the wide side of the annulus. It was eventually entrained and absorbed into the light fluid (Fig. 5-33). Ryan et al. (1992) proposed Eq. 5-15 to quantify the threshold conditions allowing this phenomenon. Such instabilities lead to azimuthal flow. Similar slumping can eventually take place when the density ratio is reversed. The slumping occurs in the direction of flow.

  Tehrani et al. (1993) observed similar gravity-driven instability in laminar flow. Jakobsen et al. (1991) observed marked effects of fluid-density difference on the removal efficiency in both turbulent and laminar flow, but they did not provide details about the basic mechanisms. However, gravity instabilities were most likely present. Gravity instabilities are also observed in numerical simulations (Fig. 5-31, lower right).

- **Shear instabilities**
  An interface between two Newtonian fluids flowing at different velocities is intrinsically unstable. This is the well-known Kelvin-Helmholtz instability in which waves form (Fernando, 1991). Gabard (2000) observed a similar interface instability between a static non-Newtonian fluid and a flowing Newtonian fluid (Fig. 5-34). At present, there is no clear understanding of these instabilities for non-Newtonian fluids. Note that these instabilities are thought to originate from the drag stress at the interface of the two fluids. This stress is not included in most 2D models.

### Table 5-6. Reynolds Numbers, Friction-Pressure Drops, and Wall Shear Stresses Calculated for Three Displacement Fluids and Three Different Centered Annuli, in Both Systeme International (SI) and U.S. Units.

<table>
<thead>
<tr>
<th>ID (in.)</th>
<th>OD (in.)</th>
<th>Flow Rate = 2 bbl/min [318 L/min]</th>
<th>Flow Rate = 5 bbl/min [769 L/min]</th>
<th>Flow Rate = 10 bbl/min [1,590 L/min]</th>
<th>Flow Rate = 15 bbl/min [2,385 L/min]</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>$N_{Re}$ -</td>
<td>$(dp/dz)_f \text{ (psi/1,000 ft)}$</td>
<td>$\tau_w \text{ (lbf/100 ft}^2$</td>
<td>$N_{Re}$ -</td>
</tr>
<tr>
<td>4</td>
<td>5 ½</td>
<td>27,964</td>
<td>8.8</td>
<td>4.0</td>
<td>69,009</td>
</tr>
<tr>
<td>7</td>
<td>8.5</td>
<td>17,139</td>
<td>3.8</td>
<td>1.7</td>
<td>42,848</td>
</tr>
<tr>
<td>9.625</td>
<td>12.25</td>
<td>12,144</td>
<td>0.4</td>
<td>0.3</td>
<td>30,361</td>
</tr>
</tbody>
</table>

### Newtonian Wash—Density 1,000 kg/m³, Viscosity 1 cP

<table>
<thead>
<tr>
<th>ID (in.)</th>
<th>OD (in.)</th>
<th>Flow Rate = 2 bbl/min [318 L/min]</th>
<th>Flow Rate = 5 bbl/min [769 L/min]</th>
<th>Flow Rate = 10 bbl/min [1,590 L/min]</th>
<th>Flow Rate = 15 bbl/min [2,385 L/min]</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.102</td>
<td>0.140</td>
<td>27,964</td>
<td>999.8</td>
<td>9.5</td>
<td>69,009</td>
</tr>
<tr>
<td>0.178</td>
<td>0.216</td>
<td>17,139</td>
<td>85.3</td>
<td>0.8</td>
<td>42,848</td>
</tr>
<tr>
<td>0.244</td>
<td>0.311</td>
<td>12,144</td>
<td>8.0</td>
<td>0.1</td>
<td>30,361</td>
</tr>
</tbody>
</table>

### Power Law Laminar Spacer—Density 1,557 kg/m³, $n = 0.49$, $k = 0.0071 \text{ lbf-s/ft}^2$ [0.34 Pa-sn]

<table>
<thead>
<tr>
<th>ID (in.)</th>
<th>OD (in.)</th>
<th>Flow Rate = 2 bbl/min [318 L/min]</th>
<th>Flow Rate = 5 bbl/min [769 L/min]</th>
<th>Flow Rate = 10 bbl/min [1,590 L/min]</th>
<th>Flow Rate = 15 bbl/min [2,385 L/min]</th>
</tr>
</thead>
<tbody>
<tr>
<td>4</td>
<td>5 ½</td>
<td>1,777</td>
<td>26.3</td>
<td>11.8</td>
<td>7,088</td>
</tr>
<tr>
<td>7</td>
<td>8.5</td>
<td>848</td>
<td>20.7</td>
<td>9.3</td>
<td>3,384</td>
</tr>
<tr>
<td>9.625</td>
<td>12.25</td>
<td>285</td>
<td>5.8</td>
<td>4.5</td>
<td>1,137</td>
</tr>
</tbody>
</table>

### Turbulent Newtonian Spacer—Density 1,319 kg/m³, Viscosity 18 cP

<table>
<thead>
<tr>
<th>ID (in.)</th>
<th>OD (in.)</th>
<th>Flow Rate = 2 bbl/min [318 L/min]</th>
<th>Flow Rate = 5 bbl/min [769 L/min]</th>
<th>Flow Rate = 10 bbl/min [1,590 L/min]</th>
<th>Flow Rate = 15 bbl/min [2,385 L/min]</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.102</td>
<td>0.140</td>
<td>2,049</td>
<td>441.3</td>
<td>4.2</td>
<td>5,123</td>
</tr>
<tr>
<td>0.178</td>
<td>0.216</td>
<td>1,256</td>
<td>270.5</td>
<td>2.6</td>
<td>3,140</td>
</tr>
<tr>
<td>0.244</td>
<td>0.311</td>
<td>890</td>
<td>35.7</td>
<td>0.6</td>
<td>2,225</td>
</tr>
</tbody>
</table>

### Power Law Laminar Spacer—Density 1,157 kg/m³, $n = 0.49$, $k = 0.0071 \text{ lb-s/ft}^2$ [0.34 Pa-sn]

<table>
<thead>
<tr>
<th>ID (in.)</th>
<th>OD (in.)</th>
<th>Flow Rate = 2 bbl/min [318 L/min]</th>
<th>Flow Rate = 5 bbl/min [769 L/min]</th>
<th>Flow Rate = 10 bbl/min [1,590 L/min]</th>
<th>Flow Rate = 15 bbl/min [2,385 L/min]</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.102</td>
<td>0.140</td>
<td>1,777</td>
<td>594.0</td>
<td>5.7</td>
<td>7,088</td>
</tr>
<tr>
<td>0.178</td>
<td>0.216</td>
<td>848</td>
<td>407.6</td>
<td>4.5</td>
<td>3,384</td>
</tr>
<tr>
<td>0.244</td>
<td>0.311</td>
<td>285</td>
<td>130.3</td>
<td>2.2</td>
<td>1,137</td>
</tr>
</tbody>
</table>
These models are thus intrinsically unable to reproduce this class of instabilities.

### Turbulent eddies and local pressure bursts

In turbulent flow, eddies are carried with the flow, and they create pressure fluctuations. The pressure varies at any given time and in any given place. The pressure variations are transmitted to the static layer as fluctuating stresses that may be sufficient to fluidize gelled layers and solids beds (Plett, 1985).

These pressure fluctuations may eventually be large enough to create an instantaneous negative differential pressure across the mud filtercake, which can cause detachment. This mechanism is similar to backpulse cleaning used in other industries.

Shear flow over a bed of particles creates drag and lift forces on individual particles. This can lead to particle fluidization and entrainment by the flow. This is the basic mechanism used for modeling cuttings-bed erosion and transport (Doron and Barnea, 1993).

Abrasion of external mud filtercake in turbulent flow is unlikely under cementing conditions. The presence of large particles is required, a condition found in gravel-packing treatments (Johnson et al., 1992; Becker and Gardiner, 2000).

### Chemical and physico-chemical effects

Chemical and physico-chemical mechanisms include the diffusion of dispersants into the static layer (leading to the weakening of the structure), a decrease of interfacial tension by surfactants, and a change of wettability of solid particles by the action of detergents. Degradation of polymers in the static material by oxidizers or enzymes is also possible; however, this method is not presently used in cementing operations. It has become a standard practice in completion operations (Ali et al., 2001).

In summary, various turbulent cleaning mechanisms may destabilize a channel of gelled mud or a solids layer. Once the interface is disturbed, it becomes easier for the particles to detach and be carried by the flow. Turbulent flow ensures that the particles are carried all around the annulus. Chemicals present in the displacing fluids diffuse into the mud and accelerate its effective dispersion.

The variety of possible mechanisms explains why using a single parameter such as shear stress or Reynolds number is too simplistic. However, a few empirical expressions have been proposed to describe erosion.

- Martin et al. (1978) defined an erosion index that is equal to the local shear stress in laminar flow and proportional to the square of the shear stress in turbulent flow. They said that for gel breakdown, the erosion index should be at least 25% higher than the mud gel strength, but no experimental data were presented to support this definition.

- Haut and Crook (1981) defined a mud mobility factor and found an experimental correlation of this factor with the flow velocity and the displacement efficiency. Later, Smith and Ravi (1991) extended the range of operational parameters by comparing various drilling fluids. Their general conclusion was that “[muds with] similar mud mobility factors do not necessarily exhibit the same filtercake-erosion characteristics.”
Ravi et al. (1992) used a calculation similar to that of Lockyear et al. (1989) to deduce the shear strength of a mud filtercake (Eq. 5-11). This value was in the same order of magnitude as that calculated from the theoretical equation, but no direct measurement of the filtercake shear strength was performed. Ravi et al. defined an erodability index proportional to the reciprocal of the measured yield strength.

These approaches highlight the problems encountered when describing complex erosion phenomena using simple parameters. Nevertheless, present qualitative understanding allows identifying the relevant mechanisms and drawing a phenomenological picture of turbulent displacement. From here, relevant parameters can be identified despite the absence of rigorous quantitative criteria.

- At large length scales, thin washes usually channel through the mud because of their small friction-pressure gradient. However, the large density difference between the narrow and wide sides of the annulus allows gravity slumping of heavy mud, widening the channel of wash.
- At intermediate-length scales, the turbulent eddies act by diluting the mud when mixed with the wash. The eddies also carry detached mud particles into the main flow. At the wash/static-mud interface, the fluctuating hydrodynamic forces destabilize the interfaces and fluidize solids beds. This is an erosion mechanism.
- At small scales, chemicals weaken the mud structure (dispersing effect) and decrease interfacial forces. This enables easier mixing and reduces the viscosity of the wash/mud mixture. Surfactants adsorbed on surfaces are replaced by detergents, providing water-wet surfaces.

To summarize the previous discussion and experimental findings in terms of physics, the principal forces at play in turbulent displacement are inertial and buoyant forces. Increasing inertia increases pressure and velocity fluctuations. Increasing buoyancy allows large-scale slumping. Viscous forces dampen both mechanisms. The intensity of turbulence is traditionally quantified by the parameter

$$\frac{\sqrt{\langle v'^2 \rangle}}{\bar{v}},$$

the ratio of the square root of the mean square velocity fluctuation, $v'$, to mean velocity, $\bar{v}$. In established turbulent flow, this quantity is a constant. Therefore, the higher the velocity, the higher the velocity fluctuations will be. Empirically, density differences of 2 to 4 lbm/gal [0.16 to 0.36 g/cm$^3$] are sufficient to create azimuthal flow through a slumping mechanism. When considering field constraints, the best turbulent cleaning fluids are low-viscosity preflushes such as base oil or water pumped at the highest possible velocities. If possible, dispersants should be added to thin the mud, and detergents should be added to leave solid surfaces water-wet.

Only large-scale phenomena can be modeled by CFD codes. These codes require careful modeling of the azimuthal-pressure field. The evaluation of the other potential effects described above is restricted to experimental testing and empirical quantification. It is essential to make sure the test methods mimic or reproduce downhole phenomena. Various methods have been proposed that are described in Appendix B. One of the approaches is to study each of the physico-chemical effects separately, using a specific apparatus. Various cleaning solutions can thus be compared.

None of the mechanisms presented above concerning the efficiency of turbulent-flow-displacement occur instantaneously. Therefore, a minimum contact time is required to achieve complete mud removal. In the absence of a complete understanding of the effect, and the difficulty of deriving it from laboratory experiments (the length scale being too short), field experience should dictate a reasonable value when available.

For the turbulent-flow displacement technique to be successful, several criteria must be met.

- The displacing fluid must be sufficiently thin for the critical pumping rate to be achievable with field equipment. This implies that the viscosity of the displacing fluid should be much lower than that of the mud, at least under the specific flow conditions. Even if turbulent flow exists all around the annulus, the displacing fluid may channel through the mud through a viscous fingering phenomenon. In this situation, various erosion mechanisms may help break the mud channel.
- The chemical and physical properties of the displacing fluid must be carefully designed (Section 5-4). It is of utmost importance for the displacing fluid to be fully compatible with the mud. In addition, a weighted displacing fluid must be able to suspend the solids required to achieve the designed density on the surface and under downhole conditions during placement.
- A single fluid usually cannot possess all the optimal physico-chemical requirements. A sequence of fluids is therefore required.

Even if the above conditions can be fulfilled, there are certain well conditions that can make this technique impractical or impossible.
- For an unweighted displacing fluid, the volume necessary to achieve a given contact time may be such that pore pressure cannot be controlled.
- For weighted displacing fluids, the critical pumping rate for turbulent flow may exceed the capabilities of the available equipment, a reduction in flow rate may occur when the displacing fluid rounds the shoe because of U-tubing, or the required volume of fluid may be cost-prohibitive.
- Weak formations with low fracture gradients may not be able to withstand the pressures associated with high displacement rates.
- Unstable formations may not be able to withstand the high velocities without being eroded.

5-3.7 Experimental investigations of immobile mud removal
Using a simulated borehole, Clark and Carter (1973) performed an interesting experimental study on the effect of high eccentricities on gelled mud removal by cement slurries. They observed poor displacement efficiency when the cement slurry was pumped in laminar flow. Much better results were obtained when the fluids were pumped under partially turbulent flow conditions (Fig. 5-35) for the same calculated frictional pressure. They also observed that, for a given pressure drop, the results improved as the viscosity of the displacing fluid decreased. McLean et al. (1967) showed that turbulent flow in itself does not reduce channeling. In some cases, high shear stresses from laminar flow lead to reduced mud channeling.

These results show that the friction pressure, hence the shear stress, does not fully characterize the cleaning properties of the displacing fluid. In addition to this parameter, turbulent flow has specific features that laminar flow does not display (Section 5-3.6).

Lockyear and Hibbert (1988) and Lockyear et al. (1989) published some interesting experimental results that are supported by theoretical arguments. For efficient mud displacement in an eccentric annulus, the friction pressure during the displacement should meet the condition given by Eq. 5-11. This equation, which assumes that the mud is flowing on the narrow side of the annulus, was verified by their experimental results (Table 5-7 and Fig. 5-36).

Lockyear and Hibbert also claimed that the velocity of the displacing fluid should be greater than zero on the narrow side of the annulus far away from the interface, a condition McLean et al. (1967) found unnecessary. As discussed in Section 5-2, satisfying such conditions does not guarantee optimal circulation efficiency, because both fluids may flow completely around the annulus but with a large interfacial-velocity difference between the narrow and the wide side. Lockyear and Hibbert (1988) gave only a partial answer to this problem. For standoff values of 50% in the absence of density differences, they observed a sharp transition between severe and minimal channeling for an average Reynolds number of 1,500 for the displacing fluid. This confirms that good displacement may be obtained, even in eccentric annuli, when the Reynolds number of the displacing fluid is in the upper-laminar or turbulent-flow range.

Tehrani et al. (1992) performed a series of carefully controlled laminar flow experiments that demonstrated the importance of density contrast and rheological hierarchy. An interesting result was the observation of azimuthal instabilities that improve displacement. These instabilities were further described by Tehrani et al. (1993). Large density differences promote instabilities, while high flow rates have the opposite effect. However, these azimuthal instabilities in laminar flow leave a fine strip of mud on the narrow side.

Ryan et al. (1995) investigated mud cleanup in horizontal wells. They concluded that increased flow rate had the clearest positive effect; however, little information was given about the fluids used. Van Vliet et al. (1995) studied filtercake removal in a slim hole with a poor standoff. The best conditions leading to maximum mud removal corresponded to a mud with low gel strength and a thin filtercake. All of the displacing fluids were in laminar flow, and increasing the contact time of the spacer had no effect.

Gabard (2000) studied how the layer of displaced fluid left on the wall of a pipe can be displaced under laminar flow. The condition that the shear stress of the
<table>
<thead>
<tr>
<th>Experiment</th>
<th>B</th>
<th>C</th>
<th>D</th>
<th>E</th>
<th>G</th>
</tr>
</thead>
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<tr>
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<td>KCl/P</td>
<td>KCl/P</td>
<td>KCl/P</td>
<td>KCl/P</td>
</tr>
<tr>
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<td>44/12</td>
<td>39/13</td>
<td>41/13</td>
<td>38/8</td>
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<tr>
<td>Density (sg)</td>
<td>1.62</td>
<td>1.62</td>
<td>1.62</td>
<td>1.63</td>
<td>1.69</td>
</tr>
<tr>
<td>10-s/10-min gel†</td>
<td>11/12</td>
<td>11/12</td>
<td>13</td>
<td>13</td>
<td>5</td>
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<td>12</td>
<td>12</td>
<td>12</td>
<td>14</td>
<td>9</td>
</tr>
<tr>
<td>Spacer type</td>
<td>Type A</td>
<td>Type A</td>
<td>Type A</td>
<td>Type A</td>
<td>Type B</td>
</tr>
<tr>
<td>$\mu_p/\tau_y$ (cp/100 lbf/ft²)</td>
<td>33/9</td>
<td>39/5</td>
<td>43/11</td>
<td>56/18</td>
<td>28/2</td>
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<tr>
<td>Density (sg)</td>
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<td>1.62</td>
<td>1.62</td>
<td>1.63</td>
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<tr>
<td>10-s gel</td>
<td>6</td>
<td>7</td>
<td>9</td>
<td>16</td>
<td>1</td>
</tr>
<tr>
<td>Volume pumped (bbl)</td>
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<td>5.0</td>
<td>5.3</td>
<td>6.4</td>
<td>6.0</td>
</tr>
<tr>
<td>Cement type</td>
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<td>Neat G</td>
<td>Neat G</td>
<td>Neat G</td>
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<td>33/40</td>
<td>21/20</td>
<td>33/37</td>
<td>47/38</td>
</tr>
<tr>
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<td>1.9</td>
<td>1.9</td>
<td>1.80</td>
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<tr>
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<td>22</td>
<td>17</td>
<td>28</td>
<td>23</td>
</tr>
<tr>
<td>Volume pumped (bbl)</td>
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<td>7.0</td>
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<td>0</td>
<td>0</td>
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<td>Mean standoff (%)</td>
<td>40</td>
<td>40</td>
<td>60</td>
<td>60</td>
<td>50</td>
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<tr>
<td>Narrow side gap at shoe (mm)</td>
<td>8</td>
<td>8</td>
<td>17</td>
<td>17</td>
<td>14</td>
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<td>Casing size (in.)</td>
<td>7</td>
<td>7</td>
<td>7</td>
<td>7</td>
<td>7</td>
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<td>Hole size (in.)</td>
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<td>8.625</td>
<td>8.625</td>
<td>8.625</td>
<td>8.625</td>
</tr>
<tr>
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<td>2.0</td>
<td>5.2</td>
<td>2.1</td>
<td>8.2</td>
</tr>
<tr>
<td>Maximum annular pressure drop during displacement (psi/100 ft)</td>
<td>26.0</td>
<td>4.4</td>
<td>10.5</td>
<td>16.3</td>
<td>59</td>
</tr>
<tr>
<td>Calculated minimum gap to achieve full mud displacement (mm)</td>
<td>1.9</td>
<td>12</td>
<td>5</td>
<td>4</td>
<td>1</td>
</tr>
<tr>
<td>Fluid in narrow side at shoe</td>
<td>Cement</td>
<td>Mud</td>
<td>Cement</td>
<td>Cement</td>
<td>Cement</td>
</tr>
</tbody>
</table>

† From Lockyear and Hibbert, 1988. Reprinted with permission of SPE.
‡ Gel strength is given in lbf/100 ft².
displacing fluid has to equal the yield stress of the static fluid was found to be conservative. Careful investigations of the flow at the displacement front allowed Allouche et al. (2000) to propose less-severe criteria, which were verified by experiments (Fig. 5-30). Interface instabilities were also observed that improved cleaning in laminar flow conditions.

There are various ways to evaluate mud displacement in the laboratory, such as visualization using model fluids, monitoring the filtercake thickness (Ravi and Beirute, 1994), and monitoring the shear bond between the set cement and the casing (Sweatman et al., 1995). Another approach is to allow the cement to set, cut the annulus into slices, and measure the percentage of annulus filled with cement (Fig. 5-37)(Kimura et al., 1999).

This short overview of experimental studies shows that immobile mud displacement in an eccentric annulus most often begins by channeling of the displacing fluid on the wide side. In laminar flow, provided the fluids have a suitable density and viscosity ratio, the interface can reach a steady state. As a result, the channel does not grow in length with time. If the channel length grows, increasing the density ratio, the viscosity ratio, or the flow rate tends to reduce the mud channel width under laminar flow conditions. A turbulent displacing fluid starts by channeling on the wide side. Eventually, the mud channel may be destabilized and cleaned, provided contact time is long enough. If this destabilization is not achieved, the mud channel is often larger than in laminar flow.

Fig. 5-36. Distribution of cement, spacer, and mud in the annulus for a number of tests (0° represents the narrow side of the annulus)(from Lockyear and Hibbert, 1988). Reprinted with permission of SPE.

Fig. 5-37. Example of mud-displacement experiment in an eccentric annulus (Kimura et al., 1999). Reprinted with permission of SPE.
5-3.8 Field studies

Deriving mud-removal information from field studies is difficult, because the available measurements are limited. At present, the most direct measurement is ultrasonic imaging or sonic logging (Chapter 15). Under appropriate conditions, mud channels and mud layers along the casing wall can be detected.

Brady et al. (1992) compared acoustic logs of wells before and after applying the job-design criteria described above (Eqs. 5-10 and 5-12) to validate these criteria. Terry (1993), Waters and Wray (1995), and Kelessidis et al. (1995) further validated these criteria, using cement bond logs.

Jakobsen et al. (1991) presented three case studies that highlight the benefit of turbulent flow when a low-density wash can be used. Alternatively, if no wash is used, a positive density difference and laminar flow can displace the mud on the narrow side in inclined sections. Kroken et al. (1995) presented other case studies showing the beneficial effect of a positive density difference in highly deviated wells, combined with very low flow rates.

Ryan et al. (1992) presented other case studies involving the application of the rules given in Eqs. 5-13 through 5-15 that lead to better cement placement. McPherson (2000) described the efficiency of turbulent flow together with pipe rotation to clean long horizontal sections, provided large volumes of wash were used.

In 1993, Hoskins et al. presented a new approach to predict mud removal efficiency based on historical data. They analyzed field data from 15 wells. In eight wells, the mud was displaced in turbulent flow. Laminar flow displacement was performed in the remaining wells. Hoskins et al. built a neural-network model to predict the cement-bond index as good, average, or bad, based on the design data. An important conclusion of this work was that the variables are interdependent. However, the variables the researchers chose were not explicitly described in the paper.

When detailed databases of cementing jobs are available, statistical analysis has been useful to pinpoint the most important parameters leading to successful operations. Using this method, Silva et al. (1996) determined that, for highly deviated wells, the most significant variables are the annular velocity, the Reynolds number, the mud yield strength, and the contact time.

Harris et al. (2001) presented the results of a statistical analysis of a large database of shoe tests and highlighted a strong correlation of successful shoe tests with casing reciprocation during cement placement. The displacement rate does not appear to be a discriminating factor between success and failure.

5-3.9 Effect of casing movement and casing hardware

Pipe movement during cement placement helps remove the mud that would otherwise be trapped on the narrow side of an eccentric annulus. The basic principle is the same as that during mud circulation; however, the physics involved is more complicated, and published models including the effect of casing movement are currently limited to the circulation process only.

On the experimental side, McLean et al. (1967) reported a few conclusions concerning the effect of casing movement on mud displacement between impermeable walls. They observed that casing rotation is a more effective mud-removal technique than casing reciprocation. However, as mentioned earlier, they emphasized that lateral motion of the casing was not allowed in their experiments, even though it is likely to happen in the field. When the pipe rotates at high speed, pure rotation becomes unstable, resulting in lateral motion. Conditions leading to unstable movement are not fully understood, but this movement clearly improves mud displacement (Sanchez et al., 1999). Lateral motion also occurs during pipe reciprocation in inclined wells (Fig. 5-12).

Mechanical devices such as scratchers, scrapers, and cable wipers (Chapter 11) also improve the efficiency of the displacement process when used in combination with casing movement (Jones and Berdine, 1940; Teplitz and Hassebroek, 1946). New hardware continues to be developed with specific objectives such as inducing local turbulent flow for better cleaning of horizontal wells (Kinzel and Martens, 1998) or wiping the casing surface during reciprocation (Dillenbeck and Simpson, 1999). These devices are attached to the pipe, and they contribute to the erosion of gelled or dehydrated mud that would otherwise remain static in the annulus.

With the improvement of necessary equipment such as rotating liner hangers, casing movement is now a common practice that has been statistically demonstrated to be beneficial (Harris et al., 2001). Casing reciprocation has been successfully used in many critical operations (Kolthoff and Scales, 1982; Holhjem et al., 1982; Ghosh et al., 1999). Typical amplitudes for casing reciprocation are on the order of 20 to 40 ft [6 to 12 m], a full cycle being completed every 1 to 5 min. These methods have an effect similar to knocking the casing or downhole vibrators (Rakhimkulov and Strugovets, 1990) to prevent gas migration problems (Chapter 9). There are three main drawbacks associated with casing reciprocation.

- Pipe reciprocation induces pressure surges and swabbing that may adversely affect well control, especially when the annular clearance is small.
There is a risk of the casing becoming stuck.

The movement amplitude is reduced downhole because of pipe stretching or buckling. Excessive casing pull may be required, especially in highly deviated wells.

Pipe rotation improves the quality of primary cement jobs, specifically liner jobs (Landrum et al., 1985; Buchan and Little, 1986), without presenting the above drawbacks. Rotary power tongs or power swivels are used, and the rotation rate usually varies between 10 and 40 rpm. The key to the success of this technique is good torque control. For this reason, power swivels are preferred.

Although not a common practice, it is worthwhile to mention that some operators use both movements (rotation and reciprocation) simultaneously with excellent results. However, one must remember that casing movement is not the panacea for all mud-displacement problems. Because the effects of casing movement have been characterized only qualitatively, other methods for improving primary cement jobs should not be omitted.

New types of external casing hardware, including permanent sensors such as fiber optics or perforation guns (Dillenbeck and Cooper, 2000) create additional mud-removal challenges because good hydraulic isolation is required around these protrusions.

5-3.10 Mud displacement in other oilfield applications—Summary and conclusions

The problem of mud displacement in primary cementing is closely related to mud-mud displacement and mud-completion fluid displacement. The correlation to hole cleaning and cuttings transport is weaker. Proper mud displacement requires displacing gelled mud, mud filtercake, and solids beds. Each has a different focus—gelled mud for primary cementing and mud-mud displacement, mud filtercake for completion operations, and solids layers for hole cleaning.

**Mud-mud displacement**

Severe compatibility problems may exist (e.g., between an OBM containing a high concentration of CaCl₂ and a bentonitic WBM) (Courtney et al., 1999). The mud can be displaced in successive steps as the drillstring is run in. Also, displacement can be performed either down the annulus (reverse circulation) or down the pipe and up the annulus. The goal is to recover the maximum amount of expensive OBM and to clean all surfaces.

**Mud-completion fluid displacement**

The main objective of mud-completion fluid displacement is to fill the hole with a noncontaminated fluid without destroying the competent filtercake lying against the formation wall.

In these two applications, the key phenomena are the hydrodynamic and chemical effects. In hole cleaning, large particles are flowing and the active phenomena are mainly based on mechanical and hydrodynamic effects, such as pipe rotation and abrasion.

The preceding discussion demonstrates that a large volume of work has been performed to better understand mud removal from various vantage points. Nevertheless, there is still no clear agreement about the best cleaning methods to apply. Practices and recommendations are still given after reviewing the fluids and their properties and requirements.

5-4 Drilling fluids, spacers, and washes

Because cement slurries are usually incompatible with most drilling fluids, intermediate fluids called preflushes are pumped as buffers to prevent contact between them. Preflushes can be chemical washes that contain no solids or spacer fluids that contain solids and are mixed at various densities.

When an incompatible pair of fluids mix, a highly viscous mass forms that can cause several problems. Cement can channel through the viscous mass. Unacceptably high friction pressures can develop during the cement job. Plugging of the annulus can result in job failure. In all of these situations, zonal isolation is compromised, and expensive remedial cementing may be required.

The use of preflushes would be unnecessary if the mud were compatible with the cement slurry. This was one of the objectives of preparing drilling fluids with blast-furnace slag (Wilson et al., 1990; Nahm et al., 1995; Daulton et al., 1995) (Chapter 7). Mud filtercakes containing blast-furnace slags are cementitous and can improve bonding with the formation (Tare, 1997). However, field use of blast-furnace slag muds is relatively rare, and well-designed preflushes remain the most commonly used solution to prevent contact between the cement slurry and the mud.

Compatibility is strongly dependent upon mud chemistry; therefore, this section begins with a brief discussion of common drilling fluids.
5-4.1 Drilling fluids

The drilling fluid is intended to allow the operator to drill the well as safely and efficiently as possible. These objectives involve controlling many mud parameters, including the rheology, density, lubricity, and inhibition properties. This is accomplished by properly adjusting the mud composition. There are many types of drilling fluids, categorized as WBMs or invert-emulsion muds.

Invert-emulsion muds are water-in-oil emulsions. The external phase is an oil, such as diesel, mineral oil, synthetic aliphatic oil, or a synthetic ester. The internal phase is an aqueous fluid containing salts to control formation integrity. The emulsion stability is maintained by selecting proper surfactants. A detailed discussion of the various mud types and chemistries is beyond the scope of this chapter. For more information, the reader is referred to specialized textbooks such as Darley and Gray, 1988.

It is worth noting that most muds are not designed for easy displacement (Harder et al., 1992; Patel, 1998). Some muds are especially difficult to displace because of their chemistry.

- Polymer muds are more difficult to displace than bentonite muds, especially when they contain components designed to strongly adsorb onto mineral surfaces.
- Invert emulsions contain emulsifiers and oil-wetting surfactants that cover all polar surfaces.

Before displacement, muds are treated or conditioned to aid displacement. The primary method is to separate the cuttings from the mud by installing screens on the shale shaker with finer mesh size and centrifuging the fluid. When no such equipment is available, an alternate method is to dilute and chemically treat the mud. The appropriate treatment depends on the mud type. Bentonite muds can be thinned by adding dispersants, and polymer muds are diluted with water. Invert emulsions can be diluted with the base oil and are usually loaded with emulsifiers to maintain or improve their stability.

OBMs are often less compatible with cement slurries than WBMs.

- The aqueous phase usually contains high concentrations of calcium chloride and calcium hydroxide. Such compounds have a strong gelling or accelerating effect on cement slurries (Chapter 3).
- Emulsifiers in the mud may adsorb on the cement grains, inhibiting hydration (Harder et al., 1992, 1993).

Fluid compatibility also depends on the cement-slurry composition. For example, Sweatman et al. (1995) reported that salt-saturated cement slurries are less interactive with OBMs than those made with fresh water.

The actual mud in a well is often significantly different from one prepared in the laboratory, owing to aging, cuttings contamination, and various treatments made while drilling. WBMs may contain a significant amount of oily components from various parts of the mud circuit, such as formation hydrocarbon, diesel fuel, grease, and pipe dope. Therefore, mud-cement slurry compatibility tests should be performed with representative samples from the field. The compatibility-test procedures are described in Appendix B.

5-4.2 Preflushes

Although the primary purpose of preflushes is to prevent commingling of the drilling fluid and cement slurry, they may also aid mud displacement. As discussed previously, mud displacement occurs at various levels. In general, fluid rheology and density determine the bulk displacement, while, on a smaller scale, the preflush chemistry ensures cleaning of the annular walls. Preflushes should have three principal attributes. They must

- be compatible with both the mud and the cement slurry
- present optimal rheology and density under downhole conditions to ensure good bulk mud displacement
- have appropriate chemistry to clean solid surfaces and leave them water-wet.

In addition, preflushes should not cause formation damage by excessive filtration and changes of rock wettability (Gambino et al., 2001) (Chapter 6). Often, a single fluid cannot meet all of these requirements. In such cases, multiple preflushes can be pumped in sequence (Boyington et al., 1989).

5-4.2.1 Washes

Washes are preflushes with a density and a viscosity very close to that of water or oil. Consequently, they can easily be pumped in turbulent flow. They act according to the mechanisms described in Section 5-3.6: mud dispersion, tangential erosion of mud layers, and leaving the casing and formation surfaces water-wet for optimal cement bonding.

When WBMs are used, the simplest wash is fresh water (Warembourg et al., 1980; Haut and Crook, 1981; Smith and Crook, 1982; Sauer, 1987). However, for more efficient mud thinning and dispersion, chemical washes that contain dispersants and surfactants are more commonly used (Evanoff and Cook, 1988). The dispersants...
are often similar to those used in cement slurries—poly-naphthalene sulfonates (Wieland and Woods, 1975), lignosulfonates, tannates, or more environmentally friendly compounds like polycarboxylic acid derivatives. The surfactants help clean oily compounds adsorbed onto solid surfaces. They are selected according to the application.

When an invert emulsion is used as drilling fluid, the chemical wash is either a mixture of water, mutual solvents, and surfactants or an oil wash followed by a water-base chemical wash (Motley et al., 1974; Bannister, 1987b).

- The oil is either the same as that in the drilling fluid or is a specific compound such as a terpene or terpene derivative (Ray and Hines, 1999).

- Mutual solvents are compounds that will incorporate water-base and oil-base compounds into a single phase. They are normally added at a concentration between 1 and 10 vol%. A typical mutual solvent is ethylene glycol monobutyl ether.

- The surfactants are mixtures of various compounds, because a single product cannot achieve the various requirements defined above. In addition, these products must be adapted to the base oil and the emulsifier system of the invert emulsion. Anionic and nonionic surfactants are used to water-wet the casing and formation, while oil-wetting surfactants such as quaternary fatty ammonium salts are used to clean oil-base drilling fluid from the walls (Motley et al., 1974).

Nonionic surfactants are commonly classified according to their hydrophilic-lipophilic balance (HLB). Surfactants with low HLB values are more compatible with hydrophobic compounds and are used with low polarity base oils such as linear olefins. Surfactants with higher HLB values are used with polar base oils such as esters. In Table 5-8, HLB values and their related and typical applications are listed.

Surfactants are frequently toxic to marine species; consequently, very stringent regulations for surfactants exist in offshore areas. Many of the most common and efficient surfactants, such as ethoxylated nonylphenols (Weigand and Totten, 1986), are no longer allowed offshore. Therefore, biodegradable and less-toxic surfactants have been introduced, including alkyl glucosides (Nilsson, 1996; Hill et al., 1997) and other sugar-base surfactants. They are less efficient than the traditional surfactants but provide an adequate balance between cleaning performance and toxicity.

Selecting the type and concentration of surfactant and solvent is made through laboratory testing, using various complementary methods adapted to the wash objectives (mud thinning, tangential erosion, water-wetting, and compatibility). The test procedures are described in Appendix B.

### 5-4.2.2 Spacers

**Spacers** are preflushes with carefully designed densities and rheological properties (Warembourg et al., 1980). One of the simplest examples of a spacer is the *scavenger slurry* (Brice and Holmes, 1964), a low-density cement slurry with a low fluid-loss rate that can easily be pumped in turbulent flow. Scavenger slurries have two principal drawbacks. They are frequently incompatible with drilling fluids and are prone to severe sedimentation. Spacers are more complicated chemically than washes. Below is a description of the most common ingredients.

**Viscosifiers** are necessary to suspend the weighting agent(s) and control the rheological properties. They can be subdivided into two classes, water soluble polymers and clays.

- Polyacrylamides (Belousov et al., 1987)
- Guar and guar derivatives (Weigand and Totten, 1986; Wieland and Woods, 1975)

- Various biopolymers, including
  - xanthan gum. Since its introduction in 1964, xanthan gum has been used extensively in the oil industry as a viscosifier and particular in drilling fluids (Weigand and Totten, 1986; Sehault and Grebe, 1987).
  - scleroglucon. This biopolymer has good particle suspension properties and thus it has been advocated for use in spacers (Parcevaux and Jennings, 1992; Donche and Isambourg, 1994).
  - welan gum. This polymer has become the most commonly used for spacers because of enhanced static and dynamic suspension properties (Powell et al., 1994).

<table>
<thead>
<tr>
<th>HLB Value</th>
<th>Application</th>
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<tr>
<td>3 to 6</td>
<td>Water-in-oil emulsion stabilizer</td>
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<tr>
<td>7 to 9</td>
<td>Wetting agent</td>
</tr>
<tr>
<td>8 to 18</td>
<td>Oil-in-water emulsion stabilizer</td>
</tr>
<tr>
<td>13 to 15</td>
<td>Detergent</td>
</tr>
<tr>
<td>15 to 18</td>
<td>Solubilizer</td>
</tr>
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</table>
and Seheult, 1991). Welan gum is a biofermented polymer (Whistler and BeMiller, 1993) that is very compatible with both drilling fluids and cement slurries.

- diutan gum. This recently introduced water-soluble gum, useful in spacers (Navarrete et al., 2000), is a biofermented polymer obtained from a naturally occurring bacterial strain of the *Sphingomonas* genus. It is a more efficient viscosifier than welan gum or xanthan gum and is stable to higher temperatures.

- nonpyruvylated xanthan gum. This recently introduced water-soluble gum, useful in spacers (Navarrete et al., 2000), is produced from *Xanthomonas campesistris*. This polymer is soluble in high-density CaCl₂ brines.

- Clays, such as bentonite, attapulgite, kaolinite, and sepiolite (Beirute, 1981; Thomas, 1981; Weigand and Totten, 1986; Evanoff and Cook, 1988). Bentonite and sepiolite are often used in combination with biopolymers (Carpenter et al., 1998).

*Dispersants* enhance the compatibility of the spacer with WBMs and cement slurries and disperse the weighting agent in the spacer. The most common dispersant is polynaphthalene sulfonate (Weigand and Totten, 1986; Guillot et al., 1986).

*Fluid-loss control agents* are usually water-soluble polymers—guar gum (Wieland and Woods, 1975), poly(ethyleneimine) (Wieland and Woods, 1975), cellulose derivatives (Weigand and Totten, 1986; Guillot et al., 1986), and polystyrene sulfonate (Guillot et al., 1986). Sometimes the same polymer functions as both a viscosifier and fluid-loss control agent (Wieland and Woods, 1975). The inorganic clays discussed above also have a beneficial influence on fluid-loss control.

*Weighting agent(s)* are used to obtain the desired spacer density—silica flour, fly ash, calcium carbonate, barite, hematite, ilmenite, and manganese tetraoxide (Thomas, 1981).

*Surfactants* increase the compatibility of spacers with OBMs and leave the casing water-wet (Sauer, 1987). The same nonionic or anionic surfactants described above for washes are usually appropriate.

Optionally, NaCl or KCl may be used to protect or prevent the dissolution of massive salt formations or fresh-water-sensitive shales (Wieland and Woods, 1975; Smith and Crook, 1982). Maroy (2002) proposed using quaternary ammonium salts to prevent the swelling of native clays.

In addition to water-base spacers, other types of spacers have been described.

- An original idea for the removal of OBMs has been described by Oliver and Singer (1986)—a water-free mixture of surfactants and an alcohol. Excellent compatibility with the mud and the cement slurry has been obtained.

- Hydroxypropylcellulose polymers may be used to provide both low viscosity to allow turbulent flow and particle transport requirements. Such materials impart sufficient viscosity to suspend the weighting agent(s) during mixing and pumping on the surface; however, when a critical temperature is reached during pumping downhole, the polymer is no longer soluble and the viscosifying effect is lost, permitting turbulent-flow displacement in the annulus (Bannister, 1981). The turbulent action keeps the weighting material suspended.

- Carney (1974) described an emulsion spacer used to displace invert emulsion muds, together with an extensive list of goals for the spacer including compatibility with muds and cements, no effect on cement properties, tolerance to contamination, good fluid-loss properties, low viscosity and easy mixing.

- Sweatman et al. (1995) described settable spacers to remove OBMs. The compositions contain blast-furnace slag (Chapter 7).

- Degni and Marcinkevicius (1999) presented field cases in which foamed spacers were used in depleted areas. The spacers decreased the bottomhole pressure. The addition of nitrogen also raised the yield stress of the spacer and provided better mud displacement.

- Spacer sequences were developed for difficult-to-displace invert emulsion muds (Ali et al., 1998; Ray and Hines, 1999; Gilmour et al., 2003), combining water-base suspensions and a nonaqueous terpene-base solvent.

Because of their relatively high viscosity, spacers are most often flowing in the laminar flow regime during mud displacement. However, their composition can be optimized to decrease their viscosity without compromising stability, allowing turbulent-flow placement. Designing a spacer fluid with optimal rheological properties for a specific job is a tedious task. The rheology depends on many factors, including the concentration of viscosifying polymer and weighting agent, temperature, and the base-fluid composition (fresh water, seawater, or concentrated salt solution). To address this problem, Théron et al. (2002) built a neural network model from a database of fluid properties. One describes the necessary rheological behavior, and the model provides a theoretical fluid composition that will meet the goal.
5-5 Cleaning-fluid sequence—current practices

Krause (1986) clearly distinguished the three key objectives of mud displacement in the context of completion fluids. These objectives also apply to cementing.

1. Remove the mud from the annulus.
2. Keep incompatible fluids apart, or at least minimize their mixing.
3. Remove all solids from the walls.

To achieve these goals, different pills are used, each designed to perform a specific function. In short, viscous spacers separate incompatible fluids, and chemical washes clean the pipe walls. From there, various combinations are possible, depending on the well requirements. Once the mud has been conditioned, the following fluid sequences are recommended.

- For a WBM: viscous spacer–seawater (or fresh water)–chemical wash–viscous spacer
- For an OBM: oil–viscous spacer–seawater (or fresh water)–chemical wash–viscous spacer

Parlar et al. (2002) further justified the cleaning-fluid sequences and recommended four general steps.

1. The mud is conditioned (i.e., cleaned and thinned). If it cannot be sufficiently thinned before displacement, the first fluid of the sequence acts as a diluent. For an OBM, it will be the base oil. Water is often sufficient for WBMs.
2. The bulk of the mud is displaced with a spacer that is more viscous than the mud, the push-pill. The displacement should be piston-like.
3. The walls of the annulus (casing and formation) are then cleaned in turbulent flow with a thin fluid containing adequate surfactants. A key design requirement for this step is the contact time. This fluid must leave both the steel and formation walls water-wet. Turbulent flow may also contribute to complete removal of the “fluffy” part of the filtercake (Mathis et al., 2000).
4. Eventually, this dirty fluid (a mixture of various surfactants and mud) is displaced by a second viscous spacer that prevents cement-slurry contamination.

This basic sequence is often adjusted according to the compatibility of consecutive fluids. Depending on well conditions and operators, priority may be given to viscosity ratio or density ratio for spacers. For large vertical holes, the focus is on density hierarchy. For highly deviated holes, the viscosity ratio becomes the major requirement. A spacer combining high density and viscosity, together with pipe rotation, remains the ultimate solution to clean and transport solids (Power et al., 2000).

The volume of fluid in Step 3 is adjusted according to the effectiveness of Step 2. The minimum contact time may vary from a few minutes to 10 min if channeling of the spacer through the mud is likely. One would think that chemical washes would not channel through the viscous spacer because of their low density and turbulent-flow regime; however, some job failures can be clearly attributed to chemical-wash channeling. Advanced displacement simulators such as that of Bittleston et al. (2002) can help design jobs to prevent such channeling situations (Fig. 5-31). The empirical method to prevent gravity-driven instabilities is to pump low-density fluids down the annulus and to pump heavy viscous fluids down the pipe and up the annulus. Unlike in completion operations, this is very rarely possible in primary cementing.

5-6 Other cement-placement problems

This chapter has shown that much effort is expended to optimize the behavior of fluids in the annulus. Ironically, fluids that are designed for proper upward displacement in the annulus can behave improperly as they travel down the casing.

When no mechanical plugs are used to separate fluids as they travel down the inside of the casing, commingling of the fluids naturally occurs at the interfaces. As a result, slugs of mixed fluids eventually arrive at the shoe as the sequence of fluids is pumped. The mixed fluids may have rheological properties that could adversely affect mud displacement in the annulus. In extreme cases, complete fluid swapping may occur inside the casing because of density differences. This effect becomes more important for large-diameter tubulars, for which buoyancy forces predominate over viscosity forces. Two basic situations are distinguished below: purely laminar flow and turbulent flow.

For laminar flow in a vertical cylinder, the nonuniform velocity profile across a pipe causes the displacing fluid to finger at the middle. Griffin and Valko (1997) adapted the approach of Beirute and Flumerfelt (1977) to this geometry for Newtonian laminar flow. Despite these highly idealized conditions and the limitations of the numerical method, their study clearly showed that, regardless of the relative fluid properties and flow conditions, the displacement is not piston-like. If the casing is not vertical, slumping will occur, leading to an increased length of intermixed fluids.

Crawshaw and Frigaard (1999) solved the slumping problem for situations in which the average of the flow rates across the pipe section (the mean flow) is zero. This condition occurs during cement-plug placement (Chapter 14).
As soon as intermixing between two successive fluids takes place, the interface is much less defined and may become more stable. This phenomenon of interface stabilization by gradually varying the fluid properties was demonstrated by Dumore (1964) for flow through porous media. These results have not been extended to flow through pipes, but Wilson (1991) and Chan (2001) used the same principle to minimize fluid intermixing. Conversely, when the fluid viscosity reaches a maximum value at some mixing ratio—i.e., the fluids are incompatible—the general consensus is that the instability will be increased, as Dumore showed for other conditions.

Intermixing can be minimized if one of the fluids is in turbulent flow. In turbulent flow, the volume of intermixed fluids is much smaller. Debacq et al. (2001 and 2003) showed that, for limiting conditions of zero mean flow and large enough turbulence, the volume of mixed fluid obeys the Taylor turbulent dispersion law (Taylor, 1954). The Taylor dispersion law states that the concentration in the mixing front follows an error function. The width of this front, \( \Delta w \), increases with the square root of time or volume pumped, \( \Delta w = \sqrt{\Delta t} \), with \( D \) being the dispersion coefficient. Unpublished experimental results (J.P. Crawshaw and N. Quisel, 2000) show that this law provides a reasonable estimate for the mixing length in a pipe flow situation. Thus, Taylor turbulent dispersion law provides a lower bound for the volume of mixed fluids.

The volume of mixed fluid can also be minimized by using an inner string or stab-in assembly. These configurations achieve two goals: minimizing the pipe internal volume and maximizing the fluid velocity so that turbulent flow occurs (Al-Buraik et al., 1998). Nonetheless, the best method to minimize the mixing is to use at least two mechanical plugs. Boyington et al. (1989) described production casing cement jobs in which four wiper plugs were used. A limitation to the number of wiper plugs is the need to either interrupt the cement job to reload the cement head or use special cement heads that can contain three plugs (Fraser et al., 1996; Chapter 11). At present, the use of three-plug heads is limited to special situations such as deepwater wells.

As fluids travel down the inside of the casing, a thin layer of the displaced fluid may remain on the steel surface. This is particularly common with OBM. Such layers are not likely to be removed by hydrodynamics alone. As the top wiper plug travels down the casing, it removes the mud layer and a slug of mud gradually accumulates. When the top wiper plug lands, the mud fills the space between the float collar and the casing shoe.

When the cement slurry breaks through the wiper plug, it is unlikely to remove all of the mud around the shoe. As a result, contaminated cement may remain in this region, and the set cement will be weaker than desired. This is commonly called “green cement.” Hibbeler et al. (2000) proposed a solution to the situation when gelled mud remains underneath the float collar: a fluid-diversion plate is inserted underneath the float-shoe valve, creating local turbulent flow that is sufficient to clean the gelled mud.

Brady et al. (1992) and Terry (1993) drew attention to situations when the casing shoe is far above the bottom of the hole. After cement placement, the unfavorable density difference between the tail slurry and the mud left in the shoe track may lead to fluid swapping, hence poor cementing of the casing shoe (bad cement log and shoe test). This phenomenon is detailed in Chapter 14. Practical solutions include placement of a viscous pill or cement plug below the casing shoe or running the casing as close to the bottom of the hole as possible.

### 5-7 Qualitative recommendations

Mud removal is a complex problem. The principal causes of poor mud displacement during primary cementations were identified more than 40 years ago. Since then, extensive research has been performed, and this work has led to the development of cementing practices that are effective in the majority of situations.

- Mud gel strength, yield point, and plastic viscosity should be reduced to minimum values before removing the drillpipe. However, one must be careful not to impair the mud’s ability to suspend the weighting agent.

- The best possible centralization should be obtained. Software is available to determine the optimal design.

- In cases in which mud removal difficulties are expected (e.g., hole irregularities, high gel strength, poor fluid-loss control, and poor centralization), the pipe should be equipped with scratchers, scrapers, or cable wipers. Pipe movement should also be planned.

- Before the preflushes are pumped, sufficient time should be allowed to circulate at least two annular volumes of mud at the highest rate possible without losing returns. A better procedure involves using tracers to monitor the volume of circulatable mud and circulating until this volume represents at least 85% of the hole volume.

- If the mud viscosity cannot be decreased sufficiently, the mud and spacer should be separated by a mutually compatible preflush. For OBM, the wash must contain a sufficient amount of surfactants to ensure a smooth transition to the water-base spacer.
If possible, a chemical wash should be used. The volume of wash should be sufficient to ensure a contact time of at least 8 min across the zone of interest.

The density and rheological properties of the spacer should lie between those of the mud and lead slurry. The spacer volume should correspond to at least 500 ft of annular length. When these conditions are difficult to achieve, more-detailed designs with a numerical simulator can more precisely determine the properties that provide the best displacement.

Mixing of fluids in the casing should be prevented by the use of mechanical plugs.

For complex situations, a better understanding and quantitative recommendations are required. No simple rule can be defined that covers all processes. Two-dimensional numerical simulators can simulate laminar flow displacements with reasonable accuracy; however, modeling of turbulent flow remains a challenge.

### 5-8 Acronym list

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Definition</th>
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<tbody>
<tr>
<td>1D</td>
<td>One-dimensional</td>
</tr>
<tr>
<td>2D</td>
<td>Two-dimensional</td>
</tr>
<tr>
<td>3D</td>
<td>Three-dimensional</td>
</tr>
<tr>
<td>API</td>
<td>American Petroleum Institute</td>
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<tr>
<td>CFD</td>
<td>Computational fluid dynamics</td>
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<tr>
<td>ECD</td>
<td>Equivalent circulating density</td>
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<tr>
<td>HLB</td>
<td>Hydrophilic-lipophilic balance</td>
</tr>
<tr>
<td>ID</td>
<td>Inside diameter</td>
</tr>
<tr>
<td>ISO</td>
<td>International Organization for Standardization</td>
</tr>
<tr>
<td>OBM</td>
<td>Oil-base mud</td>
</tr>
<tr>
<td>OD</td>
<td>Outside diameter</td>
</tr>
<tr>
<td>SI</td>
<td>Système International</td>
</tr>
<tr>
<td>STO</td>
<td>Standoff</td>
</tr>
<tr>
<td>WBM</td>
<td>Water-base mud</td>
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6-1 Introduction

Ideally, the interactions between a cement slurry and the formation it contacts are minimal. The following points describe how most engineers would prefer the cement slurry and formation to behave.

- The cement slurry is placed in the casing-formation annulus and remains there. During placement, all of the circulatable mud is removed and is replaced by uncontaminated cement. A negligible amount of filtrate enters the formation; no formation fluid enters the annulus during slurry placement or the setting period.

- During placement, the cement slurry flows tangentially to the formation face and does not erode or destabilize the wellbore. The formation is sufficiently strong to resist the pressures exerted during cement-slurry placement, and the slurry remains in the annulus during the setting period.

- The interactions between the cement and the formation are limited to establishing a strong bond at the interface to ensure perfect zonal isolation.

Unfortunately, in the real world, undesirable interactions between the cement and the formation can arise, leading to various problems.

- Owing to the pressure differential between the annulus and the porous formation, fluid exchanges occur. Filtration of the aqueous phase of the cement slurry into the formation can lead to partial or total dehydration of the slurry and to formation damage as the fluid interacts with the rock. Deposition of a filtercake on the formation face is generally beneficial in limiting the volume of cement-slurry filtrate entering the formation; however, the filtercake may restrict the annular space, leading to increased friction pressure and impaired pressure transmission. Influxes of formation fluid into the annulus can lead to other undesirable phenomena such as gas migration.

- When the formation contains certain clay minerals, cement slurry-to-clay interactions may compromise hole stability unless the chemical compositions of the drilling fluid, chemical wash, spacer, and cement slurry are compatible. The formation mineralogy may also affect the development of a competent bond with the set cement.

- When the formation contains soluble evaporite minerals, it may dissolve unless the wellbore fluids are modified to prevent or minimize dissolution.

- Formations that contain gas hydrates can pose serious challenges during well construction (Collett et al., 2000). Gas hydrates are solids composed of water, ice and hydrocarbon gas. They are stable only under conditions of high pressure and low temperature. If heated, gas hydrates will melt and liberate hydrocarbon gas. This large-volume expansion and release of a flammable material can lead to hazards. Therefore, the wellbore-fluid properties must be adjusted to prevent destabilizing gas hydrates.

This chapter discusses all of these interactions in detail. The mechanisms of fluid loss and lost circulation are presented together with methods to control them. The effect of formation mineralogy and mud filtercakes on bonding is also presented.

6-2 Fluid loss

When cement slurries are pumped against the formation, the pressure differential between the slurry and the formation leads to filtration. The aqueous phase of the cement slurry escapes into the formation, leaving the solids behind. Depending on the relative importance of erosional forces during fluid flow and sticking forces caused by filtration, the solids can form an external filtercake along the formation wall or remain suspended in the cement slurry. A small amount of solids may also enter the larger pores in the formation, creating an internal filtercake.

During primary cementing, the cement slurry flows along the formation wall, and a dynamic tangential filtration process takes place. In most cases, drilling mud,
chemical washes, and spacers have encountered the forma-
tion before the cement slurry; thus, some filtration into the formation has already occurred. Later, when pumping ceases, a static filtration period takes place. During remedial cementing, the filtration is largely static.

Insufficient fluid-loss control may be responsible for primary cementing failures owing to excessive increases in slurry viscosity during placement, annular bridging, or accelerated pressure declines during the waiting-on-cement (WOC) period. In addition, invasion of cement filtrate into the formation can cause damage and reduce production (Bannister and Lawson, 1985; Economides and Nolte, 2000; Yang and Sharma, 1991; Hill et al., 1997). On the other hand, fluid loss can have some positive effects, such as improving cement-to-formation bonding and increasing the formation fracturing pressure. However, these usually do not outweigh the drawbacks.

Fluid loss-control agents have been added to well cement slurries for decades, and the industry has long recognized that they can significantly improve the quality of both primary and remedial cement jobs. Various simple fluid-loss criteria have long been used to justify the level of fluid-loss control required to achieve good cementing results (Christian et al., 1976). However, field validation of these criteria has been difficult. More recently, studies have evaluated how much fluid-loss control is required for a given situation.

In this section, basic information concerning static and dynamic cement-slurry filtration is presented. Then, fluid loss in the context of primary and remedial cementing is discussed. Finally, field measurements of fluid loss are covered.

### 6-2.1 Static filtration

If the filtercake is assumed to be incompressible, the fluid-loss volume will be proportional to the filtercake volume. Therefore, the fluid-loss volume per unit area, $V/A$, is proportional to the filtercake thickness, $h_{fc}$ (Eq. 6-1).

$$h_{fc} = \frac{K_{dep} \times V}{A}$$  \hspace{1cm} (6-1)

$K_{dep}$ is an experimentally determined proportionality constant, also called the “deposition constant” by Binkley et al. (1958). $K_{dep}$ values have been measured by various researchers and found to vary between 1.0 and 2.5 (Christian et al., 1976; Cook and Cunningham, 1977; Desbrières, 1988).

During static filtration, the filtrate volume varies with the square root of time (Eq. 6-2). If one assumes the filtercake is incompressible (i.e., constant permeability), the filtrate volume is also a function of the square root of the differential pressure across the filtercake (Outmans, 1963).

$$V = A \sqrt{\frac{2k_{fc} (\Delta p) t}{\mu_{filt} \times K_{dep}}},$$  \hspace{1cm} (6-2)

where

$A = $ filtration surface area

$k_{fc} =$ filtercake permeability

$\Delta p =$ differential pressure

$t =$ time

$V =$ cumulative filtrate volume

$\mu_{filt} =$ filtrate viscosity.

Cement filtercakes are incompressible when deposited under a sufficiently high differential pressure (Hook and Ernst, 1969), which varies from formation to formation. If the cement filtercake is compressible, $k$ may vary with time. It is also important to note that the filtercake may consist of more than one layer. There may be previously deposited filtercakes from the drilling fluid and spacer (Sherwood, 1993).

Static filtration is relatively easy to simulate in the laboratory. The American Petroleum Institute (API) and the International Organization for Standardization (ISO) define standard testing procedures and equipment (Appendix B). In a pressurized test cell, the aqueous phase of the cement slurry passes through a metal screen. A filtercake of cement solids forms on the screen. This test allows one to measure various parameters.

- Volume of filtrate versus time
- Chemical composition of the filtrate fluid (e.g., ionic and polymeric contents)
- Properties of the filtercake (e.g., thickness, porosity, permeability, and shear strength)
- Effects of filtration pressure on the above properties
- Deposition constant, $K_{dep}$

All of these properties can also be correlated with the cement-slurry composition, especially the type and concentration of fluid-loss additive (Chapter 3).

Several studies have described the effect of the slurry composition on filtercake permeability, filtrate viscosity, and $K_{dep}$.

- Hook and Ernst (1969) found that $k$ decreases as the concentration of fluid-loss additive increases.
- Desbrières (1988) determined that, in the presence of polymeric fluid-loss additives, the filtercake permeability easily decreases by a factor of 100, while the filtrate viscosity increases by a factor of no more than 5.
The particle-size distribution of the cement-slurry solids has a profound effect on the filtercake permeability. Latex-modified cements form thin filtercakes with very low permeability. Engineered particle-size (EPS) cement slurries have naturally low fluid-loss rates owing to the low water content and optimized packing of the filtercake (Boisnault et al., 1999; Chapter 7).

Baret and Boussouira (1989) described emulsion cement slurries with reduced fluid loss. They attributed this effect to capillary forces. However, the reduced fluid loss may also be caused by the deformability of oil droplets, as observed with oil-base muds (OBM) (Aston et al., 2002).

Cement filtercakes have much lower water content than the original cement slurry. Consequently, once the filtercake hardens, its strength is higher than that of the cement slurry.

6-2.2 Dynamic filtration

Dynamic filtration is much more complex than static filtration and has been studied extensively in the context of hydraulic fracturing fluids (Clark and Barkat, 1990; Constien et al., 2000) and drilling fluids (Fordham et al., 1988; Fordham and Ladva, 1992; Osisanya and Griffith, 1997), but research concerning the dynamic fluid-loss behavior of cement slurries is sparse.

Initially, dynamic filtration is similar to static filtration. Eventually, however, erosion limits the filtercake growth (Hook and Ernst, 1969). In addition, the mud filtercake limits the cement fluid loss. The most dominant features of dynamic filtration are summarized below.

Filtercake buildup is not fully reversible. If a filtercake is deposited while pumping at a low flow rate, increasing the flow rate will not remove it entirely (Bannister, 1978). This has also been observed with drilling fluids; it is known as “irreversible particle attachment” (Fordham et al., 1988).

The filtercake is mechanically eroded. Nevertheless, owing to limited particle penetration into the formation, sufficient material remains to reduce the fluid-loss rate of a subsequent fluid.

Once the dynamic filtration regime is reached, the filtration rate is constant. Bannister (1978) measured cement-slurry filtration rates through a mud filtercake of the order of $10^{-6}$ m/s (filtration rate per unit area—0.006 cm$^3$/min/cm$^2$). Similar filtration-rate reductions have been verified by Haberman et al. (1992). After pumping a laminar flow spacer containing a cellulose-base fluid-loss additive between the mud and the cement slurry, Bannister (1978) observed no significant cement-slurry filtration-rate increase when the temperature was increased (Fig. 6-1).

The erosion of a dehydrated mud filtercake by laminar hydrodynamic forces is clearly impossible because of the high yield stress of the mudcake. Depending on the filtration pressure, Cerasi et al. (2001) measured yield-stress values of 0.014 psi [100 Pa] for OBM filtercakes and between 0.14 to 14.5 psi [10$^3$ and 10$^5$ Pa] for water-base-mud (WBM) filtercakes. The yield stresses of cement filtercakes are similar to those of WBM filtercakes (unpublished data, Daccord, 2002). Dehydrated muds have yield stresses too high to be removed by the drag force of a fluid flowing past them (Ravi et al., 1992). However, the mudcake can be partially removed with casing movement, or by using devices such as scratchers or jets (Chapter 11) attached to the casing string. Highly turbulent flow can substantially erode mud filtercakes (Beirute et al., 1991), but the underlying mechanisms remain unknown.

In the special case of air-drilled holes, no mud filtercake exists when the cement slurry contacts the formation; consequently, filtration is entirely controlled by the cement slurry (Brown and Ferg, 2003). Spacer fluids (described below and in Chapter 5) are often pumped ahead of the cement slurry to establish fluid-loss control.

![Fluid-loss rate vs. temperature](image-url)  
*Fig. 6-1. Effect of temperature and fluid sequence upon dynamic fluid-loss rates. Reprinted with permission of SPE.*
6-2.3 Fluid loss in primary cementing

Cement slurries are often preceded by chemical washes and spacers, which have two principal objectives.

1. Prevent direct contact of the cement slurry with the mud
2. Help remove the maximum amount of circulatable mud (Chapter 5)

The second objective is achieved through both hydrodynamic forces and chemical interactions. The chemical washes often contain mud thinners or clay stabilizers (Maroy, 2002; Rueda et al., 2003). Spacers have a more complex role. They are designed to remove the maximum amount of mud from the formation face and also to create a filtercake. The filtercake minimizes spacer filtration and eventually helps control cement-slurry fluid loss (Crinklemeyer et al., 1976). Jones et al. (1991) considered spacer fluid loss to be of secondary importance, because the contact time with the formation is short. As chemical washes and spacers are pumped past the formation, one can expect the mud-filtercake properties and the filtration rate to change.

Filtrate invasion can be reduced by chemical reactions that deposit an impermeable skin on the formation wall. For example, Whitfill and Whitebay (1990) proposed using a mixture of partially hydrolyzed polyvinyl acetate and potassium silicate. An impermeable precipitate forms when this mixture encounters divalent ions.

Moving the casing or liner during mud conditioning and cement placement is recommended to help displace the mud. When the casing is reciprocated, the swabbing pressure may lift large parts of the external mudcake, leaving the rock face bare; however, the internal filtercake remains in place. Ladva et al. (2001) established that a very small negative differential pressure is sufficient to break or lift a mudcake.

From an operational point of view, the cement slurry must be placed at the designed depth and at the designed flow rate without abnormal pumping pressures and with minimal fluid exchange with the formation. Fluid loss may compromise these objectives in various ways.

- Fluid loss increases the proportion of solids in the flowing slurry. The increased solids content modifies the slurry properties. Slurry density (Moran, 1986), slurry viscosity, and friction pressure increase (King, 1966; Christian et al., 1976; Beirute, 1988). Turbulent intensity decreases, shortens the thickening time (Baret, 1988), and decreases the total volume (Moran, 1986).
- If cement solids are deposited and form a filtercake that does not erode, the annular clearance is reduced, leading to increased friction pressure (Beirute, 1988; Cook and Cunningham, 1977). In an extreme situation, the filtercake may bridge and plug the annulus, resulting in job failure.
- Finally, the filtrate that enters the formation interacts with the formation minerals and modifies the rock properties and the saturation profile. The filtrate may also interact with the oil. All of these effects are commonly known as formation damage (King, 1966; Bannister and Lawson, 1985; Jones et al., 1991).

Once the cement slurry is placed and pumping has stopped, subsequent static filtration is dependent upon the way pressure is maintained in the annulus. At this point, further fluid loss affects the ability of the cement sheath to provide zonal isolation (Christian et al., 1976; Cook and Cunningham, 1977; Sabins et al., 1984a and 1984b; Bannister and Lawson, 1985; Chenevert and Jin, 1989; Daccord et al., 1992; Prohaska et al., 1994).

Along with the negative consequences discussed above, fluid loss has a few positive effects.

- The increased solids content of the slurry (i.e., its partial dehydration) leads to higher compressive strength, shorter transition time, lower permeability, and less hydration shrinkage.
- The presence of a hard cement filtercake on the formation face can improve the bond between the cement sheath and the formation.
- The increased cement-slurry viscosity can aid displacement of the drilling mud when viscous forces are greater than turbulent ones.

In addition to the above technical considerations, the cost of fluid-loss additives can be sufficiently high to play a large role in deciding the level of fluid-loss control. Fluid-loss additives commonly double the cement-slurry cost.

6-2.3.1 Fluid-loss criteria

Common fluid loss-control guidelines, known as fluid-loss criteria, have largely been developed from field experience, not theoretical models. Fluid-loss rates are usually measured using the API static test (Appendix B), even though many of the design criteria for fluid-loss control are linked to dynamic filtration rather than static filtration. For example, Hartog et al. (1983) defined a general maximum fluid-loss rate of 200 mL/30 min for oil wells and 50 mL/30 min for gas wells.

The 50-mL/30 min limit was also adopted by Christian et al. (1976), based on field results. On the other hand, Dillenbeck and Smith (1997) showed that, for a specific gas field, no fluid-loss control was necessary to obtain good cement jobs.
In subsequent sections, each of the major effects cited above are detailed, and quantitative criteria are attached to them, following the approach of Daccord and Baret (1994).

6-2.3.2 Effects of fluid loss on cement-slurry properties

In this section, a hypothetical primary-cementing situation is considered in which a cement slurry flows along a permeable formation. As shown in Fig. 6-2, the hypothetical well is vertical, and there are no preflushes between the mud and the cement slurry. Only water can enter the permeable formation, and all of the cement particles remain in the slurry and do not form a dynamic filtercake. The fluids are assumed to be incompressible.

This simplified problem allows one to derive quantitative fluid-loss criteria and rank the relative importance of each, although the direct use of these criteria is limited by our knowledge of dynamic filtration. In Table 6-1, numerical values are given for each phenomenon described, based on specific well data.

![Fig. 6-2. Schematic of the well geometry.](image-url)

Table 6-1. Numerical Values and Predicted Effects of Various Phenomena for a Specific Simple Well Condition

<table>
<thead>
<tr>
<th>Situation</th>
<th>Result</th>
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<tr>
<td>Mud filtercake thickness ~1 mm, permeability ~1 μD</td>
<td>Equation 6-7</td>
</tr>
<tr>
<td>Cement filtercake thickness ~1 mm, permeability ~100 μD</td>
<td>Filtration velocity ~1 × 10⁻⁶ m/s</td>
</tr>
<tr>
<td>Differential pressure = 140 psi [10 bar]</td>
<td>Equation 6-8</td>
</tr>
<tr>
<td>Filtrate viscosity = 1 cp</td>
<td>Relative volume of slurry lost = 0.38%</td>
</tr>
<tr>
<td>Hole size = 10 in., casing size = 7 in.</td>
<td>Equation 6-9</td>
</tr>
<tr>
<td>Length of permeable formation = 300 ft [91 m]</td>
<td>Relative slurry-density increase = 0.18%</td>
</tr>
<tr>
<td>Length of cement above the permeable zone = 1,000 ft [305 m]</td>
<td>Equation 6-10</td>
</tr>
<tr>
<td>Pump rate = 8 bbl/min [1,270 L/min]</td>
<td>Maximum admissible filtration velocity (v_{\text{filt}})_{\max} = 7.5 × 10⁻⁶ m/s</td>
</tr>
<tr>
<td>Slurry density = 15.8 lbm/gal [1,900 kg/m³]</td>
<td>Equation 6-9</td>
</tr>
<tr>
<td>Slurry porosity (\phi_{cs} = 50%)</td>
<td>Relative slurry-density increase = 0.18%</td>
</tr>
<tr>
<td>Cake porosity, (\phi_{fc} = 30%)</td>
<td>Equation 6-10</td>
</tr>
<tr>
<td>Mud density = 12 lbm/gal [1,440 kg/m³]</td>
<td>Maximum admissible filtration velocity (v_{\text{filt}})_{\max} = 7.5 × 10⁻⁶ m/s</td>
</tr>
<tr>
<td>The solids content increases by a relative amount of 0.9%, which leads to a relative slurry viscosity increase of 4.5%.</td>
<td>Equation 6-12</td>
</tr>
<tr>
<td>Formation porosity accessible to filtrate, (\phi = 10%)</td>
<td>For a maximum admissible viscosity increase of 30%, the maximum admissible filtration velocity is (6 × 10⁻⁴) m/s.</td>
</tr>
</tbody>
</table>
At any depth \( z \), the mass conservation equations for
the two phases, water and cement (volume fractions \( f_w V \) and \( f_c V \), respectively), are written as follows.

\[
\pi d_{\text{hole}} v_{\text{filt}} + \frac{\pi}{4} \left[ (d_{\text{hole}})^2 - (d_{\text{csg}})^2 \right] \frac{d(f_w V \times v)}{dz} = 0
\]

\[
\pi \left[ (d_{\text{hole}})^2 - (d_{\text{csg}})^2 \right] \frac{d(f_c V \times v)}{dz} = 0,
\]

\[
f_w V + f_c V = 1
\]

(6-3)

where

- \( d_{\text{hole}} \) = hole diameter
- \( d_{\text{csg}} \) = casing diameter
- \( v \) = slurry velocity in the annulus
- \( v_0 \) = slurry velocity below the permeable formation
- \( v_{\text{filt}} \) = filtration velocity into the formation
- \( z \) = vertical coordinate.

For a constant filtration velocity, the conservation equations can be written in a simplified form.

\[
v_0 + \frac{d(f_w V \times v)}{dv_{\text{df}}} = 0,
\]

\[
\frac{d \left[ (1-f_w V) v \right]}{dv_{\text{df}}} = 0
\]

(6-4)

with

\[
v_{\text{df}}(z) = \frac{4 \left( d_{\text{hole}} \times v_{\text{filt}} \times z \right)}{v_0 \left[ (d_{\text{hole}})^2 - (d_{\text{csg}})^2 \right]}.
\]

(6-5)

\( v_{\text{df}} \) is a dimensionless coordinate but can also be considered as a dimensionless filtration rate. Effectively, for \( z \) equal to the permeable-layer thickness \( (h_{pl}) \), \( v_{\text{df}} \) is equal to the ratio of the total filtration rate to the slurry pump rate. With the slurry velocity and water-volume fraction (slurry porosity) given by \( v_0 \) and \( f_w V \), respectively, the slurry velocity and porosity at the top of the permeable layer are given by the integration of the above system of equations.

Practical use of these equations requires knowledge of the filtration velocity, \( v_{\text{filt}} \). Three situations are possible:

- competent mud filtercake is present, upon which a cement filtercake is deposited
- only cement filtercake is present
- there is no filtercake.

No filtercake can be formed when the formation permeability is so low that the particles cannot stick to the formation surface (Fordham et al., 1988). In this case, the filtration rate is entirely determined by the formation permeability, according to Darcy’s law. When filtercakes are present, the filtration velocity obeys the following equation.

\[
\frac{1}{(h_{fc})_{\text{mud}} + (h_{fc})_{\text{cem}}} \frac{\Delta p}{\mu_{\text{filt}}}
\]

(6-7)

The term \( h_{fc}/k_{fc} \), the ratio of cake thickness to its permeability, is the cake resistance to flow. In Eq. 6-7, both a mudcake and a cement cake are considered with respective resistances equal to \( (h_{fc})_{\text{mud}}/(k_{fc})_{\text{mud}} \) and \( (h_{fc})_{\text{cem}}/(k_{fc})_{\text{cem}} \).

Slurry volume
Based on the above analysis, the volume of slurry in the annulus is reduced by an amount equal to the total filtrate volume.

\[
\Delta V = \pi d_{\text{hole}} \left( D_{pl} - D_{toe} \right) \frac{v_{\text{filt}} \times h_{pl}}{v_0}.
\]

(6-8)

Slurry density
At the end of cement placement, the density of the slurry above the permeable zone is increased to the following value:

\[
\rho = \left[ \rho_0 - \left( v_{\text{df}} \times \rho_w \right) \right] \times \frac{1}{1-v_{\text{df}}}
\]

(6-9)
where
\( \rho \) = density of slurry above permeable zone
\( \rho_0 \) = initial slurry density
\( \rho_w \) = density of water.

The upper slurry-density limit corresponds to total slurry dehydration. In this limiting situation, the solid-volume fraction reaches a maximum value, equal to the solid-volume fraction of the cement cake, \( f_{fc} \), in a first approximation. Equation 6-6 allows one to quantify this limit and derive a maximum admissible filtration velocity, an important fluid-loss guideline.

\[
f_{fc} = \frac{f_{sV} - v_{df}}{1 - v_{df}} \quad \text{or} \quad \left( \frac{v_{df}}{v_{df}} \right)_{\text{max}} = \frac{f_{sV} - f_{fc}}{1 - f_{fc}} \quad (6-10)
\]

Hydrostatic pressure increase
Owing to both the decrease of slurry volume (Eq. 6-8) that is replaced by an equal volume of mud and its increase in density (Eq. 6-9), the hydrostatic pressure is increased by an amount equal to

\[
\Delta p = \left( \rho_{mud} - \rho_w \right) \left( D_{pl} - D_{loc} \right) g v_{df}, \quad (6-11)
\]

where
\( \rho_{mud} \) = mud density
\( \rho_w \) = water density
\( g \) = acceleration of gravity.

When the formation has a low fracturing pressure and additional hydrostatic pressure creates a risk of inducing losses into the formation, this equation can be used as another fluid-loss guideline.

Slurry thickening time
Decreasing the water/cement ratio accelerates cement thickening (Fig. 6-3). The amount by which the thickening time varies is strongly dependent on slurry density and composition. In critical situations, laboratory tests should be performed to determine the sensitivity of the thickening time to variations in slurry density.

Slurry viscosification
As the water/cement ratio decreases, both the viscosity and the yield stress of a slurry increase (Fig. 6-4). This is a general law for suspensions, and many theoretical or empirical models describe this dependence. Equation 6-12 is the simplest model that describes the variation of the high-shear-rate slurry viscosity, \( \mu_{slurry} \), with the effective solid volume fraction, \( f_{sV} \) (Quemada, 1998). \( f_{sV} \) is the maximum solid volume fraction in

\[
\mu_{slurry} = \mu_{s0} \left[ 1 - \left( \frac{f_{sV}}{f_{sV}} \right)_{\text{max}} \right]^{-2}, \quad (6-12)
\]

where \( \mu_{s0} \) = viscosity of the suspending liquid.
This law shows that the slurry becomes a solid—the viscosity is infinite—when the effective solid-volume fraction reaches a maximum value. It is therefore equivalent to Eq. 6-10, although the values for the maximum solid-volume fractions are slightly different. Figure 6-4 shows experimental data from which an empirical \((f_s)_{\text{max}}\) value can be derived. In turn, using Eq. 6-6, a maximum admissible filtration velocity is defined.

Dynamic placement pressure
An increase in slurry viscosity leads to increased friction pressure in the part of the wellbore above the permeable zone. Therefore, the placement pressure also increases. Another quantitative fluid-loss guideline may be extracted that requires more detailed calculations. An example is shown in Fig. 6-5.

Concluding remarks
It is clear that, as long as a competent mudcake governs the filtration velocity and that the well conditions approximate those used above, none of the above consequences is likely to perturb cement placement. The variations given in Table 6-1 are very small.

However, if the mudcake is damaged and the cement cake controls filtration, the filtration velocity will increase by one or two orders of magnitude. In that case, these consequences are likely to affect cement placement. The increase of slurry viscosity and corresponding dynamic pressure are often the most critical effects. These effects become especially important for narrow annuli (Waters and Wray, 1995).

### 6-2.3.3 Annular restriction and bridging

In the presence of a mudcake, filtration is limited by the mudcake; therefore, a significant cement filtercake is unlikely to form under dynamic conditions. The filtration velocity is too small to allow cement particles to stick to the wall without being immediately eroded by the flow. However, if the mud filtercake is damaged or the flow is stopped, a cement filtercake will form. The fluid-loss guideline that is derived from this mechanism corresponds to a cake thickness that is equal to the annular gap. Using Darcy’s law, the cement-filtercake thickness can be calculated (Baret, 1988). To a first approximation, one can assume that the mudcake is incompressible, whereupon the thickness of the cement cake is given by

\[
(h_{fc})_{cem} = K_{dep} \frac{V(t)}{A} = \left(\frac{k_{fc}}{k_{fc} \text{_{cem}} (h_{fc})_{mud}}\right) \left(\frac{1}{A} \sqrt{1 + \frac{2\Delta p K_{dep}}{\mu_{fil} (k_{fc})_{cem} (h_{fc})_{mud}^2} t - 1}\right).
\]

(6-13)

In the absence of a mud filtercake, the cement-filtercake thickness is deduced from Eq. 6-2:

\[
(h_{fc})_{cem} = K_{dep} \frac{V(t)}{A} = \sqrt{\frac{2(k_{fc})_{cem} K_{dep} \Delta p}{\mu_{fil} (h_{fc})_{mud}^2}} t.
\]

(6-14)

This filtercake thickness is therefore made equal to the annular gap, \((h_{fc})_{cem} = (d_{hole} - d_{csg})/2\), to obtain \((k_{fc})_{cem} K_{dep} / \mu_{fil}\). These properties are related to the API/ISO static filtration test (Eq. 6-2), and yield the maximum filtration pressure and time that will lead to annular bridging. Equation 6-15 gives the guideline when considering a cement cake alone, in terms of maximum API/ISO filtrate volume (Appendix B).

\[
\Delta p t = \Delta p_{API} \times t_{API} \left[\frac{d_{hole} - d_{csg}}{2K_{dep}} \times \frac{A_{API}}{V_{API}}\right] \times \left[\frac{\Delta p_{API} \times t_{API}}{\Delta p t}\right]^{2}
\]

or

\[
\left(\frac{V_{API}}{A_{API}}\right)_{\text{max}} = \frac{d_{hole} - d_{csg}}{2K_{dep}} \sqrt{\frac{\Delta p_{API} \times t_{API}}{\Delta p t}}
\]

(6-15)
A similar relationship can be derived for the case when a mud filtercake is present. Numerical results are shown in Fig. 6-6. Case 1 corresponds to a long filtration time under a high differential pressure. The cement filtercake is controlling the behavior; therefore, the API fluid-loss rate must be less than 50 mL/30 min to prevent annular bridging. Case 2 is for a smaller differential pressure. As soon as the mudcake resistance is higher than 0.5 mm/µD, the mud filtercake controls the behavior, and no fluid-loss control is required for the cement slurry. These typical mudcake resistance-values correspond to competent mudcakes.

6-2.3.4 Mud removal

The complexity of mud-removal mechanisms prevents deriving simple fluid-loss guidelines. Parametric studies require using numerical simulators such as those described in Chapter 5. From a qualitative standpoint, partial dehydration of the cement slurry will increase the friction pressure and wall shear stress, improving the mud-removal capability. Figure 6-7 shows an example of an eccentric casing in a deviated well. The image on the left side shows the presence of a mud channel on the narrow side of the eccentric annulus. When the viscosity of the cement slurry increases (right side of figure), the mud channel is significantly reduced.

This beneficial effect only appears when mud removal is governed by viscous forces (i.e., relatively narrow annuli). For larger annuli and smaller deviation, gravity forces usually predominate, and no significant effect of the slurry-viscosity increase is expected. Also, when thin cement slurries are used to achieve turbulent flow, the viscosity increase lowers the turbulent energy of the fluid and its mud-removal capability. Whether this decrease in turbulence can be offset by an increase in wall shear stress should be evaluated on a case-by-case basis.

6-2.3.5 Formation damage and formation invasion depth

A simple formation-damage and fluid-loss guideline is based on the maximum admissible penetration depth of cement filtrate, although a distinction must be made between filtrate-invasion depth and actual damage (Vidick and Reid, 1997). For example, assuming a piston-like displacement into the rock, the penetration depth, \( L \), of the filtrate for a cement cake filling the entire annular gap is given by

\[
L = \frac{d_{hole}}{2} \sqrt{1 - \left( \frac{d_{cyc}}{d_{hole}} \right)^2 \left( 1 + \frac{\phi \times K_{dep}}{1} \right)}
\]

where \( \phi = \) the formation porosity. After perforating, if the perforation channel extends beyond this depth, then no major effect of cement filtrate on production is expected.

---

**Fig. 6-6.** Predicted maximum cement fluid-loss volume and cake permeability versus mudcake resistance for two static cake buildup conditions. Case 1: filtration time = 6 h, pressure = 1,015 psi [70 bar]. Case 2: filtration time = 3 h, pressure = 145 psi [10 bar] (figure adapted from Baret, 1988). Reprinted with permission of SPE.
Several possible formation-damage mechanisms have been described (Cunningham and Smith, 1968; Yang and Sharma, 1991; Hill et al., 1997), including clay swelling, particles plugging pores in the formation, precipitation of calcium silicates from the cement filtrate, dissolution-precipitation of minerals from the formation, and deconsolidation of the formation. Jones et al. (1991) conducted studies with Berea sandstone cores to correlate the type of formation damage with the composition of the wellbore fluid. Severe permeability reduction was observed with freshwater spacers and latex-modified cement slurries. Potassium chloride (KCl) was generally beneficial in that it reduced clay swelling, although the filtrate volume was greater. However, Dillenbeck et al. (1991) noticed that too much KCl in cement slurries caused gelation and increased fluid-loss rates. Gambino et al. (2001) studied formation damage by OBM filtrate and cement filtrate. The OBM filtrate induced severe fines migration and wettability alteration. The cement filtrate induced little formation damage.

### 6-2.3.6 Pressure transmission during WOC

Preventing gas migration requires an integrated approach, and cement fluid loss is only one of the relevant parameters. A thorough presentation of the subject is available in Chapter 9. A number of related factors control the fluid-loss properties of the cement slurry (Christian et al., 1976; Sabins et al., 1984a and 1984b; Rae et al., 1989). For example, pressure reduction during the WOC period is directly linked to volume reduction and fluid loss. Sabins et al. (1984a and 1984b) considered the annulus to be a closed system, and allowed the fluid compressibility, $c$, to compensate for the lost volume. The corresponding pressure decrease was calculated by the following equation.

\[ \Delta p = \frac{V_{\text{fil}}}{cV_{\text{ann}}}, \]  

(6-17)

where $V_{\text{ann}}$ = the annular volume.

EQUATING this pressure reduction to the initial overpressure gives a maximum allowable fluid-loss volume for the cement slurry, $V$, which can be related to the API/ISO fluid-loss properties (Eq. 6-2).
A more detailed description of pressure reduction must include the additional effects of cement yield strength and shrinkage, as well as wellbore geometry. Chenevert and Jin (1989) and Daccord et al. (1992) presented simulation results that clearly showed the effect of cement fluid loss. These sophisticated models show that, even with excellent fluid-loss control, cement filtration may remain a critical parameter if the slurry properties are not optimized (e.g., if the slurry has a long transition time).

The fluid-loss properties of the cement slurry may have an indirect effect on gas migration prevention. For example, Christian et al. (1976) reported that, if fluid-loss control is achieved by adding a polymer that viscosifies the interstitial water, then gas percolation through the cement matrix is likely to be hindered.

### 6.2.3.7 Comparison between various phenomena and conclusions

The quantitative comparison between the various criteria defined above clearly shows that, when a risk of gas migration exists, cement-slurry fluid loss is a critical parameter. The use of quantitative criteria is of limited interest when considering cement placement because the downhole conditions are usually poorly understood, especially the filtration properties of the mudcake. Several field problems have been interpreted in terms of slurry dehydration or annular bridging. This uncertainty justifies the use of fluid-loss additives to limit potential risks.

### 6.2.4 Fluid loss during remedial cementing operations

Fluid loss has long been recognized as a critical parameter in squeeze cementing (King, 1966). However, this is only one of several important parameters, and successful remedial cementing requires one to consider many other factors (Chapter 14). In this chapter, the discussion is limited to fluid loss. For perforation plugging, fluid-loss control is required to achieve proper filtercake buildup in perforation channels. However, cement-slurry fluid loss affects other phenomena.

- The filtrate that enters the formation may lead to formation damage and may modify the formation stress conditions. Consequently, the fracturing pressure is also affected (Marangos, 1989).

- When the objective of the squeeze operation is to fill voids or mud channels behind the casing, excessive cement-slurry filtration will lead to rapid dehydration and premature pressure buildup. In these situations, a low to extremely low fluid-loss rate is required.

Binkley et al. (1958) presented a detailed model that reasonably represents perforation plugging. Also, laboratory testing can be designed to more closely resemble downhole conditions (Hook and Ernst, 1969). These studies have resulted in widely-accepted fluid-loss guidelines for perforation plugging.

For other applications, quantitative criteria can be defined in a manner similar to primary cementing. For example, Eq. 6.18 (derived from Eq. 6-15) gives an estimate of the API/ISO fluid-loss rate required for a cement cake to bridge a mud channel of thickness \( h \).

\[
\frac{V_{API}}{A_{API}} = \frac{h}{K_{dep}} \times \sqrt{\frac{\Delta p_{API} \times t_{API}}{\Delta pt}}.
\]

If the downhole filtration conditions are similar to those of the high-pressure API test, then \( V_{API} \sim A_{API}h/ K_{dep} \). For a 1-mm thick channel and \( K_{dep} = 2 \), \( V_{API} = 1 \) mL. Clearly, in this case, extremely low API fluid-loss rates are required for the slurry to successfully fill the channel without bridging it. Practically, the best way to achieve such low fluid-loss rates without increasing the slurry viscosity has been through the use of EPS slurries (Farkas et al., 1999; Chapter 7).

### 6.2.5 Field measurements

Direct measurement of the effects of fluid loss during primary cementing jobs is difficult. Variations in slurry properties, surface pressure, and flow rate are small. The situation is slightly better for remedial cementing operations, in which surface-pressure measurements can be interpreted in a useful way. These two situations are considered below.

During primary cement jobs, the simultaneous occurrence of many phenomena prevents extracting the contribution of cement-slurry fluid loss in an unambiguous way (Evanoff and Cook, 1988). Despite this problem, Beirute (1988) proposed a method to diagnose six potential cement job problems by analyzing surface parameters. Two of these problems are of relevance: flow restrictions and slurry dehydration. In both situations, the free-fall periods would be shorter than normal. For a downhole restriction, the slope of the pressure curve should be normal, while it should be steeper for slurry dehydration.

The situation is more favorable when the pressure decline can be monitored after pumping has stopped. Two primary factors contribute to short-term pressure variations, namely compressibility and fluid loss, as quantified by Eq. 6-17. This analysis is commonly performed during fracturing treatments to determine the...
fluid-loss coefficient of the fluid (Nolte, 1983; Gulrajani and Nolte, 2000) as well as for a pressure integrity test (Postler, 1997).

Haberman et al. (1992) used a similar technique to specifically determine fluid loss from drilling fluids and cement slurries. Two methods provided very consistent results: interpretation of the pressure decline and measurement of the pump rate required to maintain a constant surface pressure. Measurements were performed before and after cementing. As a general conclusion, it was found that the fluid-loss rate of the drilling fluid was lower than that measured in the laboratory and that the cement-slurry fluid loss was mainly controlled by the drilling-fluid filtercake.

6-3 Lost circulation

Lost circulation (or lost returns) is defined as the total or partial loss of drilling fluids or cement slurries into highly permeable zones, cavernous formations, and fractures or fractures induced during drilling or cementing operations (Goins, 1952). Lost circulation must not be confused with fluid loss, which has been previously described. Figure 6-8 depicts how the fluid-loss process is more related to primary porosity, whereas lost circulation can occur in formations with both primary and secondary porosities. Lost circulation is a problem that is best attacked before performing the cement job. Therefore, the treatment of lost circulation during drilling is included in the following discussion.

6-3.1 Consequences of lost circulation

Lost circulation can be an expensive and time-consuming problem. During drilling, this loss may vary from a gradual lowering of the mud level in the pits to a complete loss of returns. The major consequences of lost circulation are shown in Table 6-2.

To effectively solve lost circulation with the correct technique, it is necessary to know the severity of the losses, the type of lost circulation zone, and the drilling history of the well just before the losses occurred.

![Fig. 6-8. Fluid loss versus lost circulation.](image)

<table>
<thead>
<tr>
<th>Table 6-2. Major Consequences of Lost Circulation</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Drilling</strong></td>
</tr>
<tr>
<td>Loss of mud</td>
</tr>
<tr>
<td>Lost time</td>
</tr>
<tr>
<td>Poor cement job</td>
</tr>
<tr>
<td>Reduced safety</td>
</tr>
<tr>
<td>Stuck in hole</td>
</tr>
<tr>
<td>Wasted casing string</td>
</tr>
<tr>
<td>Failure to reach target depth</td>
</tr>
<tr>
<td>Blowout and kill operations</td>
</tr>
<tr>
<td>Downhole blowouts</td>
</tr>
<tr>
<td>Environmental incident</td>
</tr>
</tbody>
</table>

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6-3.2 Classification of the severity of losses

A standard severity classification for lost circulation is shown in Table 6-3.

<table>
<thead>
<tr>
<th>Type of Losses</th>
<th>Severity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Seepage (minor)</td>
<td>&lt; 10 bbl [1.5 m³]/hr</td>
</tr>
<tr>
<td>Partial (medium)</td>
<td>10 to 100 bbl [1.5 m³ to 15 m³]/hr</td>
</tr>
<tr>
<td>Severe (massive)</td>
<td>100 to 500 bbl [15 m³ to 75 m³]/hr</td>
</tr>
<tr>
<td>Total (complete)</td>
<td>Unable to keep the hole full</td>
</tr>
</tbody>
</table>

6-3.2.1 Seepage losses (1–10 bbl/hr [1.5 m³ to 15 m³/hr])

Seepage takes the form of very slow losses. Sometimes the losses can be in the form of filtration to a highly permeable formation, an extreme case of fluid loss. Seepage losses can also be confused with the volume of cuttings removed at the surface. One must not confuse these two completely different occurrences. If seepage losses are suspected, the bit must be pulled off bottom and the mud volumes checked with and without circulation. All mixing equipment and nonessential solids removal equipment should be turned off and baseline values recorded.

Once it is established that fluid is being lost, one must decide whether to tolerate or cure this situation. Depending on the cost of the drilling fluid, rig time, or both, one might decide to continue drilling with seepage losses. If formation damage or stuck pipe are potential problems, one should attempt to cure the losses before proceeding with drilling.

6-3.2.2 Partial losses (10–100 bbl/hr)

Partial losses are more voluminous than seepage losses; therefore, the fluid cost becomes more crucial in the decision to drill ahead or combat the losses. Drilling with partial losses can be considered if the fluid is not expensive and the pressures are within operating limits.

6-3.2.3 Severe losses (100–500 bbl/hr)

When severe losses are encountered, regaining full circulation is mandatory. This can be accomplished by pumping a lower-density fluid down the annulus (drilling mud, water, or other lightweight fluid) and monitoring the volumes required to fill the well.

6-3.2.4 Total losses

If the well becomes stable, one then calculates the hydrostatic pressure required to fill the well. If losses persist, one begins spotting conventional lost circulation material (LCM) pills and progresses to plugs if conventional treatments are unsuccessful. Owing to the reduction of hydrostatic head, the well must be monitored closely at all times for influx of fluids. It may be possible in some areas to continue drilling if the fluid cost is low and pressures are manageable.

6-3.3 Classification of lost circulation zones

Lost circulation occurs by one of two mechanisms.

- **Natural losses.** Whole fluid or cement is lost to formations that are highly permeable, unconsolidated, fractured, cavernous, or vugular.
- **Induced losses.** The mud or fluid is lost because excessive induced pressure hydraulically fractures the formation.

It is common to classify lost circulation zones into five categories.

- Unconsolidated formations
- Highly permeable/low-pressure formations (depleted zones)
- Natural fractures or fissures
- Induced vertical or horizontal fractures
- Cavernous and vugular formations

Seeping losses can occur with any type of lost circulation zone when the mud solids are not sufficiently fine to seal the formation face. Partial losses frequently occur in highly permeable gravels, small natural fractures, or as a result of fracture initiation. Complete losses are usually confined to long gravel sections, large natural fractures, wide induced fractures, or cavernous formations.
6-3.3.1 Unconsolidated formations
Coarse, unconsolidated formations can have a sufficiently high permeability for whole mud or cement slurry to invade the formation matrix (10–100 D). For whole mud or cement slurry to be lost, the average particle size of solids in the mud or cement slurry must be less than or equal to one-third the size of the formation opening (Barkman and Davidson, 1972). These losses are normally confined to shallow wells or surface holes. Rates of loss can vary from seepage to total losses. In the event that losses are total, it is sometimes common practice to continue drilling if a sufficient supply of water is available and there are no environmental or well-control concerns.

One reason for preventing shallow mud losses is that unconsolidated formations may wash out, forming a large, unstable cavity that could collapse from the overburden and rig weight. In some areas, it may be more common to drill with air, mist, and foamed or aerated muds to prevent losses. Unconsolidated formations are typically found at shallow levels and normally consist of sands or gravel; however, they can also occur in shell beds or reef deposits.

6-3.3.2 Highly permeable or depleted formations
To permit the penetration of whole mud or cement slurry, the formation permeability must be greater than 10 D; however, significant seepage losses can occur in lower-permeability consolidated sandstones. Producing formations in the same field or general vicinity may cause subnormal (depleted) formation pressure because of the extraction of formation fluids. Loss of mud to these formations requires that the passages be sufficiently large and connected to allow entry of whole mud and that the mud pressure must exceed the formation pressure. Seepage losses to severe losses can often lead to differentially stuck drillpipe. Such depleted reservoirs are found at any depth.

6-3.3.3 Natural fractures or fissures
Hard, consolidated formations may contain natural fractures that take mud when penetrated by the drillstring. The overburden must be self-supporting for a horizontal fracture to exist, but this is not the case for a vertical natural fracture. To widen a horizontal fracture, the overburden must be lifted. Vertical fractures will propagate when the fracture pressure is exceeded. A sudden loss of returns in hard, consolidated formations often indicates the presence of natural fractures.

6-3.3.4 Induced fractures
If the borehole pressure exceeds the formation parting pressure, open fractures will be created, permitting the loss of mud or cement. There are three typical circumstances when this can occur.

- An immovable mud ring may develop in the annulus owing to fluid loss. The resulting circulating-pressure increase may initiate a hydraulic fracture.
- When one is drilling through an undercompacted formation, typically found offshore, fractures can occur.
- When one is drilling from a mountaintop, the overburden pressure is low, and fracturing occurs easily.

Well irregularities, high mud weight, and rough handling of drilling tools may also help induce fractures. Simpson et al. (1988) suggested that lost circulation caused by fracture initiation is more common when using oil-base instead of water-base mud. They believed this arises from the failure to consider the compressibility of the oil under downhole conditions. They also observed that induced fractures do not “heal” readily when OBM is present.

When partial losses occur with WBM, an accepted practice is to let the hole “soak.” The mud is allowed to rest in the hole. The resulting mud filtration allows the fractures to be filled with mud solids and often permits full circulation to be restored with no mud-weight reduction. However, filtration from OBM is often too slow to be helpful. Once fractures are initiated with an OBM, fracture extension can be expected until the borehole pressures are reduced or the fracture openings can be sealed.

6-3.3.5 Cavernous and vugular formations
Large voids or caverns are sometimes encountered when drilling through certain limestone and dolomite formations as well as the soluble caprock of salt domes. Sudden and complete losses are typical of this type of zone.

6-3.4 Lost circulation while drilling
According to Messenger (1981), it is possible to classify the available lost circulation solutions into three main categories:

- bridging agents in the drilling fluid
- surface-mixed systems
- downhole-mixed systems.

There is an optimal technique for solving each particular type and severity of a lost circulation problem. Figure 6-9 shows a lost circulation decision tree to address lost circulation problems.
Fig. 6-9. Lost circulation treatment decision tree.
6-3.4.1 Bridging agents in the drilling fluid

When the loss of mud is first detected, immediate consideration should be given to the possibility of reducing and maintaining the mud weight at the minimum necessary to control the formation pore pressure. Reduced mud pressure will help combat losses no matter what types of formations are exposed. A continuing partial loss of returns is indicative of seepage and can usually be solved by decreasing the equivalent mud circulating density or by adding LCMs to the drilling mud. The equivalent mud circulating density can be reduced by decreasing the mud weight and/or adjusting its downhole rheological properties. According to their physical nature and their mechanism of action, LCMs can be classified into five different groups:

- granular
- lamellar (or flake-like)
- fibrous
- mixed
- encapsulated fluid-absorbing particles.

Granular LCMs

Granular LCMs are rigid materials that are spherical in nature. They form two types of bridges—one at the formation face and one within the formation matrix. The latter type of sealing is preferred because the particles are not easily dislodged by pipe movement in the wellbore. The effectiveness of granular LCMs depends primarily on selecting the proper particle-size distribution, with larger particles first forming a bridge across or within the void and the smaller particles bridging the openings between the larger particles (Gatlin and Nemir, 1961). This process continues until the void spaces become smaller than the drilling-mud solids. The problem finally becomes one of filtration. A blend containing a range of particle sizes is most commonly used. Such systems are usually more successful in high-solids-ratio systems such as cement slurries.

In 1976, Abrams showed that the median particle size of the bridging additive should be slightly greater than or equal to one-third the median pore size of the void. Assuming a relatively homogeneous sandstone formation in which the sand grains are of similar size, it is possible to predict the required bridging-agent particle size to bridge the pore throats of the formation matrix. These values are given in Table 6-4. In addition, Abrams determined that the minimum concentration of bridging solids is 5% by volume of solids in the final mud mix. However, Abrams' rule only indicates the amount of material necessary to commence plugging. It does not address an ideal packing sequence for optimal sealing.

<table>
<thead>
<tr>
<th>Sand Grain Size (μm)</th>
<th>Diameter of Pore Throat Opening (μm)</th>
<th>Approximate Permeability (nD)</th>
<th>Bridging Particle Size (μm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.00025 [6.46]</td>
<td>1.0</td>
<td>1</td>
<td>0.33</td>
</tr>
<tr>
<td>0.00125 [31.67]</td>
<td>4.9</td>
<td>24</td>
<td>1.63</td>
</tr>
<tr>
<td>0.0015 [38.10]</td>
<td>5.90</td>
<td>35</td>
<td>1.97</td>
</tr>
<tr>
<td>0.0017 [43.18]</td>
<td>6.68</td>
<td>45</td>
<td>2.23</td>
</tr>
<tr>
<td>0.0021 [53.34]</td>
<td>8.26</td>
<td>68</td>
<td>2.75</td>
</tr>
<tr>
<td>0.0024 [60.96]</td>
<td>9.44</td>
<td>89</td>
<td>3.15</td>
</tr>
<tr>
<td>0.0026 [73.66]</td>
<td>11.40</td>
<td>130</td>
<td>3.90</td>
</tr>
<tr>
<td>0.0035 [88.90]</td>
<td>13.76</td>
<td>189</td>
<td>4.59</td>
</tr>
<tr>
<td>0.0041 [104.14]</td>
<td>16.12</td>
<td>260</td>
<td>5.37</td>
</tr>
<tr>
<td>0.0049 [124.46]</td>
<td>19.27</td>
<td>370</td>
<td>6.42</td>
</tr>
<tr>
<td>0.0058 [147.32]</td>
<td>22.80</td>
<td>520</td>
<td>7.60</td>
</tr>
<tr>
<td>0.0069 [175.26]</td>
<td>27.13</td>
<td>740</td>
<td>9.04</td>
</tr>
<tr>
<td>0.0082 [208.28]</td>
<td>32.24</td>
<td>1,040</td>
<td>10.8</td>
</tr>
<tr>
<td>0.0097 [246.38]</td>
<td>38.14</td>
<td>1,460</td>
<td>12.7</td>
</tr>
<tr>
<td>0.0116 [294.64]</td>
<td>45.61</td>
<td>2,080</td>
<td>15.2</td>
</tr>
<tr>
<td>0.0138 [350.52]</td>
<td>54.26</td>
<td>2,960</td>
<td>18.1</td>
</tr>
<tr>
<td>0.0153 [381.00]</td>
<td>58.97</td>
<td>3,480</td>
<td>19.7</td>
</tr>
<tr>
<td>0.0164 [416.56]</td>
<td>64.48</td>
<td>4,160</td>
<td>21.5</td>
</tr>
<tr>
<td>0.0195 [495.30]</td>
<td>76.67</td>
<td>5,880</td>
<td>25.6</td>
</tr>
<tr>
<td>0.0232 [589.28]</td>
<td>91.22</td>
<td>8,320</td>
<td>30.4</td>
</tr>
<tr>
<td>0.0276 [701.04]</td>
<td>108.5</td>
<td>11,800</td>
<td>36.2</td>
</tr>
<tr>
<td>0.0328 [833.12]</td>
<td>128.9</td>
<td>16,600</td>
<td>43.0</td>
</tr>
<tr>
<td>0.0390 [990.60]</td>
<td>153.3</td>
<td>23,500</td>
<td>51.1</td>
</tr>
<tr>
<td>0.0461 [1,168.00]</td>
<td>181.0</td>
<td>32,800</td>
<td>60.3</td>
</tr>
<tr>
<td>0.0555 [1,396.00]</td>
<td>216.0</td>
<td>46,700</td>
<td>72.0</td>
</tr>
<tr>
<td>0.0665 [1,650.00]</td>
<td>255.0</td>
<td>65,000</td>
<td>85.0</td>
</tr>
<tr>
<td>0.0788 [1,980.00]</td>
<td>307.0</td>
<td>94,200</td>
<td>102</td>
</tr>
<tr>
<td>0.0954 [2,361.00]</td>
<td>365.0</td>
<td>133,000</td>
<td>122</td>
</tr>
<tr>
<td>0.1102 [2,793.00]</td>
<td>432.0</td>
<td>187,000</td>
<td>144</td>
</tr>
<tr>
<td>0.1317 [3,326.00]</td>
<td>515.0</td>
<td>266,000</td>
<td>172</td>
</tr>
<tr>
<td>0.1564 [3,960.00]</td>
<td>613.0</td>
<td>376,000</td>
<td>204</td>
</tr>
<tr>
<td>0.1853 [4,667.00]</td>
<td>727.0</td>
<td>529,000</td>
<td>242</td>
</tr>
<tr>
<td>0.2215 [5,610.00]</td>
<td>868.0</td>
<td>753,000</td>
<td>289</td>
</tr>
<tr>
<td>0.2636 [6,677.00]</td>
<td>1,034.0</td>
<td>1,070,000</td>
<td>345</td>
</tr>
<tr>
<td>0.3127 [7,921.00]</td>
<td>1,226.0</td>
<td>1,500,000</td>
<td>409</td>
</tr>
</tbody>
</table>

More recently, Dick et al. (2000) wrote a software application that determines the optimal blend of bridging agents according to the maximum pore size and the formation permeability. Instead of using Abrams' rule,
the software is based on the ideal packing theory (IPT) (Kaeuffer, 1973). The work of Dick et al. saw the first practical application of IPT to oilfield use.

The IPT takes a graphical approach to determine the optimal concentration of bridging material for given formation characteristics. This theory can be applied to both lost circulation pills and water- or oil-base drill-in fluids and is particularly applicable to systems used to drill or seal permeable sand, limestone, or fractured shale. This is a field-proven theory that has been applied successfully in all of the above applications. For example, the ideal particle-size distribution based on a maximum pore-throat size of 133 μm is shown in Fig. 6-10. The figure also shows the particle-size distributions for various commercial bridging materials.

Fibrous LCMs
Fibrous materials are best for controlling losses to porous and highly permeable formations because they are able to form a mat-like bridge over the pore openings. The mat reduces the size of the openings to the formation, permitting the colloidal particles in the mud to rapidly deposit a filtercake.

Lamellar LCMs
Lamellar LCMs are flat, layer-like materials with limited or no rigidity that are also designed to bridge and form a mat on the formation face. These LCMs also provide the best results when treating losses to permeable and porous formations.

Mixed LCMs
Blends of granular, flake, and fibrous LCMs are also effective. These LCMs also provide a gradation of particle sizes as well as a variation of material types for sealing different classes of lost circulation zones.

Howard and Scott (1951) performed a series of experiments comparing the fracture sealing capacity of various types of LCMs with their concentration in drilling mud (Fig. 6-11). They found that granular LCMs were more effective than the laminar or fibrous materials for sealing larger fractures. Table 6-5 is a list of typical commercial materials, their particle-size distributions, and the normal concentrations used.

Nayberg and Petty (1986) performed a laboratory study comparing the effectiveness of fibers, flakes, granules, and thermoset rubber in controlling mud losses to simulated medium-size (0.13 in. [3.3 mm]) fractured formations. They claimed that a blend of medium- and fine-grained (10- to 200-mesh) particles of thermoset rubber performed better than the conventional LCMs. An interesting observation was that granular LCMs sometimes exhibited a “channeling” phenomenon. When a high pressure differential and an insufficient mud-solids concentration existed, a bridge at the formation face, or within the formation matrix, could not develop.

The conventional LCMs tend to be supplied in three grades—fine, medium, and coarse.

- Under most circumstances, fine materials will pass through the shaker screens and stay in the mud.
- Medium materials tend to be screened out of the mud but most likely will not plug jets or other downhole tools.

![Fig. 6-10. Ideal particle-size distribution of bridging agent for a formation with a 133-μm pore size. Particle-size distributions (PSDs) of various commercial bridging agents are also shown (from Dick, 2000).](image-url)
Fig. 6-11. Effect of concentration of LCMs when sealing fractures (after Howard and Scott, 1951). Reproduced courtesy of the American Petroleum Institute.

Table 6-5. Typical LCMs†

<table>
<thead>
<tr>
<th>Material</th>
<th>Type</th>
<th>Description</th>
<th>Concentration (lbm/bbl)</th>
<th>Largest Fracture Sealed (in.)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nutshell</td>
<td>Granular</td>
<td>50%–16 + 10 mesh 50%–10 + 100 mesh</td>
<td>20</td>
<td></td>
</tr>
<tr>
<td>Plastic</td>
<td>Granular</td>
<td>50%–10 + 100 mesh</td>
<td>20</td>
<td></td>
</tr>
<tr>
<td>Limestone</td>
<td>Granular</td>
<td>50%–10 + 100 mesh</td>
<td>40</td>
<td></td>
</tr>
<tr>
<td>Sulfur</td>
<td>Granular</td>
<td>50%–10 + 100 mesh</td>
<td>120</td>
<td></td>
</tr>
<tr>
<td>Nutshell</td>
<td>Granular</td>
<td>50%–10 + 16 mesh 50%–30 + 100 mesh</td>
<td>20</td>
<td></td>
</tr>
<tr>
<td>Expanded perlite</td>
<td>Granular</td>
<td>50%–3/16 + 10 mesh 50%–10 + 100 mesh</td>
<td>60</td>
<td></td>
</tr>
<tr>
<td>Cellophane</td>
<td>Lamellar</td>
<td>3/4-in. flakes</td>
<td>8</td>
<td></td>
</tr>
<tr>
<td>Sawdust</td>
<td>Fibrous</td>
<td>1/16-in. particles</td>
<td>10</td>
<td></td>
</tr>
<tr>
<td>Prairie hay</td>
<td>Fibrous</td>
<td>1/4-in. fibers</td>
<td>10</td>
<td></td>
</tr>
<tr>
<td>Bark</td>
<td>Fibrous</td>
<td>3/8-in. fibers</td>
<td>10</td>
<td></td>
</tr>
<tr>
<td>Cottonseed hulls</td>
<td>Granular</td>
<td>Fine</td>
<td>10</td>
<td></td>
</tr>
<tr>
<td>Prairie hay</td>
<td>Fibrous</td>
<td>3/16-in. particles</td>
<td>12</td>
<td></td>
</tr>
<tr>
<td>Cellophane</td>
<td>Lamellar</td>
<td>3/16-in. flakes</td>
<td>8</td>
<td></td>
</tr>
<tr>
<td>Shredded wood</td>
<td>Fibrous</td>
<td>3/16-in. fibers</td>
<td>8</td>
<td></td>
</tr>
<tr>
<td>Sawdust</td>
<td>Fibrous</td>
<td>1/8-in. particles</td>
<td>20</td>
<td></td>
</tr>
</tbody>
</table>

† After Howard and Scott (1951). Reproduced courtesy of the American Petroleum Institute.
Coarse materials can plug off any downhole assemblies except open ended drillpipe.

Other specialty materials are graded according to particle size or the size of the opening through which they will pass.

The first patent concerning the use of encapsulated particles to control lost circulation was that of Armentrout (1958). The technique consists of encapsulating bentonitic particles within a water-insoluble polymeric coating, through which a small hole is drilled. When the encapsulated bentonite is pumped down the wellbore, water from the mud seeps through the hole. The bentonite swells and ultimately ruptures the coating. The swollen bentonite then seals the voids in the lost circulation zone. Walker (1987) followed this by describing a technique in which the lost circulation additive is a highly water-absorbent polymer encapsulated by a protective coating. The particle size of the encapsulated particles varied from 0.1 μm to 5 mm. The casing can be a material that slowly dissolves when in contact with the wellbore fluid or a waxy substance that melts at a temperature between the bottomhole static and circulating temperatures. The polymer then absorbs water, forming a semisolid, nonflowing mass that seals the zone. The water-absorbent polymers include alkali metal polyacrylates or saponified copolymers of a vinyl ester, which have the capacity to absorb more than 100 times their weight of water. Another patent by Delhommer and Walker (1987) described a similar technique for oil-absorbing polymers, enabling the use of such systems in OBM.

6-3.4.2 Surface-mixed systems

When adding LCMs to drilling fluids does not control lost circulation, other types of fluids are often prepared at the wellsite and pumped downhole to seal the formation.

6-3.4.2.1 Cement plugs

Neat cement slurries are effective for solving seeping or minor losses and offer the advantage of providing high final compressive strengths. Slurries with a limited degree of fluid-loss control can be used to solve seeping, partial, or total losses; they may contain a mixture of clays, diatomaceous earth, and LCMs. One selects the LCM particle size according to the severity of the losses. Low-density cement systems can be used for any type of lost circulation problem. They have the added advantage of reducing the hydrostatic pressure.

Thixotropic cements are also used as cement plugs. Thixotropy is a term used to describe the property exhibited by a system that is fluid under shear (i.e., pumping or agitation) but develops a gel structure when the shear is stopped (Chapter 4). In practical terms, thixotropic systems are fluid during mixing and displacement but rapidly form a rigid, self-supporting gel structure when pumping ceases. When a thixotropic slurry enters a lost circulation zone, the velocity of the leading edge decreases and a gel structure starts to form (Chapter 7). As the gel strength develops, resistance to flow increases until the entire zone is plugged (Childs et al., 1985). Such systems are very effective for solving severe lost circulation in naturally fractured formations.

6-3.4.2.2 High-fluid-loss squeezes

When a high-fluid-loss slurry is squeezed into the lost zone, it readily dehydrates so that solids pack the fractures and form a seal. A typical high-fluid-loss slurry contains a mixture of diatomaceous earth, bridging agents, and barite suspended in either water or oil.

These slurries are effective for sealing induced fractures in which external bridging is not paramount and when it is important to achieve a high pressure drop in the fracture. The mud solids should provide the necessary fines for bridging. In low-porosity, fractured formations, 10 lbm/bbl [0.03 kg/L] of fine fibrous LCM is usually added. Coarse or granular LCMs should not be added because they may prevent ingress of the slurry into the fracture. Coarse or granular LCMs may also act as a proppant if they invade the fracture.

Hydrostatic pressure is often sufficient to seal the loss zone. A light squeeze pressure (100–300 psid [4.79–14.4 kPa]) may be applied to open up and then seal fractures. High-fluid-loss slurries can be pumped through the drillbit jets.

6-3.4.2.3 Polymer-base crosslinked systems

Crosslinking is the linking of two independent polymer chains by a crosslinking agent that spans or links two chains. Polymeric plugs (or “pills”) are a blend of polymers, crosslinking agents, and fibrous LCMs designed to plug naturally fractured or vugular formations. They can be activated by a crosslinking agent, time, temperature, or shearing at the bit (Quinn et al., 1999; Caughron et al., 2002). After setting, the pills can be rubbery, ductile, and spongy soft. Crosslinked pills are solid but tend to have a rubbery consistency with little compressive strength. The shear strength is high enough to support a fluid column but low enough to allow removal by washing or jetting. The setting time is fully controllable by using either a retarder or accelerator that is based upon the temperature of the thief zone or bottom hole. Most plugs can be weighted up to 16.0 lbm/gal and are thermally stable up to 300°F [149°C]. Care should be exercised in or near the producing interval, because the plugs cannot be degraded and produced back. Different types of poly-
mer-based crosslinked pills (PCP) are engineered for specific thief zones and lost circulation mechanisms (Table 6-6).

The blend consists of medium- to high-molecular-weight crosslinking polymers and sized fibrous materials. When added with a biopolymer and activated with a combination of crosslinking agent, time, and temperature, it produces a rubbery, ductile, spongy, set gel (Fig. 6-12).

6.3.4.2.4 Other surface-mixed systems

Systems that do not contain Portland cement usually involve a gelling agent with an activator. After a given period of time, or because of a temperature increase, the components react to form a nonflowing mass. The advantage of such systems is the ability to predict when the mixture will change from a liquid to a solid. In general, they are most applicable to partial lost circulation problems in high-permeability sandstones or for sealing microfissures.

Sharp (1966) first described the use of an aqueous solution of sodium silicate and urea that, at temperatures above 145°F [63°C], reacts to form a hydrosol of silicic acid. With time, the hydrosol converts to a silica gel within the formation, providing a firm structure that is essentially impervious to fluid. The gel time may be preselected by varying the relative concentrations of the reactants; however, the downhole temperature must exceed 145°F [63°C] for the reaction to proceed at a useful rate. This feature permits the preblending of the mixture several hours before the operation commences.

Elphingstone et al. (1981) described the use of halogenated hydrocarbons, more specifically sodium trichloroacetate, as an activator for aqueous silicate solutions. The addition of silica flour (325-mesh) was recommended to increase the viscosity of the final gel.

Smith (1986) used reducing sugars, such as lactose and fructose, as thermally responsive activators for silicate solutions. For applications in which the well temperature is below 120°F [49°C], the addition of small amounts of a reactive salt (such as calcium chloride) was suggested to provide short gelling times without having to increase the concentration of the reducing sugar.

Table 6-6. Description of Polymer-Base Crosslinked Pills†

<table>
<thead>
<tr>
<th>Product Name</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>PCP for large natural fractures and vugular lost circulation zones</td>
<td>PCP for large natural fractures or vugular zones is a one-sack blend of polymers, crosslinking agents, and medium-to-coarse fibrous LCMs. When activated with time and temperature, PCP produces a soft-to-medium strength, rubbery, ductile, spongy, set gel that effectively prevents loss of fluid to the formation. The LCM in PCP packages is a fibrous cellulose type containing a wide variation of particle sizes.</td>
</tr>
<tr>
<td>PCP for induced fractures and porous and/or permeable formations</td>
<td>For induced fractures or matrix losses (i.e., microfractured network or permeable formations) the PCP has been reengineered for maximum penetration and higher strength. In this case, the blend consists of medium-molecular-weight crosslinking polymers and fine-sized fibrous materials. When added with biopolymer and activated with a combination of crosslinker, time, and temperature, PCP produces a medium-to-hard strength, rubbery, ductile plug. The LCM in this variety of PCP comprises specially sized and concentrated fibrous cellulose containing a mixture of fine particle sizes to plug deep fractures, faults, and matrices. The crosslinking agent is packaged separately. Thus, the plug can be mixed ahead of time and will not cross-link. The crosslinker is added just before pumping.</td>
</tr>
</tbody>
</table>

† from Ivan et al. (2002).
For OBM, additives such as organophilic clays, soaps, asphaltic materials, and mineral fibers have been used for many years to impart gel strength. These materials have various shortcomings, most notably limited thermal stability. Patel and Salandanan (1985) developed an improved system that comprises a polymeric oil gellant that imparts thixotropic properties to oil-base drilling fluids. The gelling agent is thermally activated, forming a gel structure as soon as the temperature exceeds 140°F [60°C]. The structure melts at 250°F [121°C]. Figure 6-13 depicts the activation of the gelling agent by a combination of temperature and shear. The gelling mechanism of the material involves a swelling of the initial agglomerates and a gradual release of the individual oligomer chains (Stage 2). The oligomers associate with other particulate materials in the system to form a thixotropic fluid.

As the temperature rises, swelling starts to take place and eventually a stable system forms when equilibrium is achieved. In the presence of shear and temperature, this process takes place much faster (Stage 3). When the system is totally activated, it remains stable even if the temperature drops (Stage 4).

Yearwood et al. (1988) and Vidick et al. (1988) described the use of an internally activated low-viscosity silicate solution that, depending on the fluid design and the temperature, gels rapidly. The final gel is strong and permanent, with very little free water at temperatures up to 355°F [180°C]. To demonstrate the sealing capacity of this system, a series of laboratory experiments was performed using core plugs with different permeabilities. The results demonstrated that, once the gel has formed in the formation matrix, the system is able to withstand differential pressures greater than 1,500 psi/ft [0.24 Pa/m] (Table 6-7).

**Table 6-7. Performance of Internally Activated Silicate System in a Core-Flow Test†**

<table>
<thead>
<tr>
<th>Core Nature</th>
<th>Average Permeability to Water (D)</th>
<th>Saturating Fluid</th>
<th>Test Temperature (°F [°C])</th>
<th>Extrusion Pressure Resistance for 1 ft of Plugged Core (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>20/40 fracturing sand 6</td>
<td>Fresh water</td>
<td>105 [40.5]</td>
<td>1,200</td>
<td></td>
</tr>
<tr>
<td>Porous sandstone 2</td>
<td>Fresh water</td>
<td>105 [40.5]</td>
<td>&gt;1,500</td>
<td></td>
</tr>
<tr>
<td>Porous sandstone 2</td>
<td>Diesel oil</td>
<td>105 [40.5]</td>
<td>&gt;1,500</td>
<td></td>
</tr>
<tr>
<td>Porous sandstone 2</td>
<td>Brine</td>
<td>105 [40.5]</td>
<td>&gt;1,500</td>
<td></td>
</tr>
<tr>
<td>Fissured limestone 1</td>
<td>Fresh water</td>
<td>140 [60.0]</td>
<td>&gt;1,500</td>
<td></td>
</tr>
<tr>
<td>Fissured limestone 1</td>
<td>Brine</td>
<td>140 [60.0]</td>
<td>&gt;1,500</td>
<td></td>
</tr>
<tr>
<td>20/40 fracturing sand 6</td>
<td>Fresh water</td>
<td>175 [79.4]</td>
<td>&gt;1,500</td>
<td></td>
</tr>
<tr>
<td>20/40 fracturing sand 6</td>
<td>Brine</td>
<td>175 [79.4]</td>
<td>&gt;1,500</td>
<td></td>
</tr>
</tbody>
</table>

† Yearwood et al. (1988). Reprinted with permission from the Petroleum Society of CIM.
Vidick et al. (1988) presented an equation to relate the gelling time of the silicate systems to the active matter content and the temperature. Equation 6-19 helps not only to predict the gelling time at a particular temperature for a given active matter content but also to calculate the gel time variations resulting from slight bottomhole temperature fluctuations.

\[
t_{gel} = K_T \times x E_{act} \times e^{-\frac{E_{act}}{R T}}
\]

(6-19)

where

- \(E_{act}\) = Activation energy (kJ/mol)
- \(K_T\) = A constant (function of the temperature)
- \(K_x\) = Coefficient related to the active matter content
- \(R\) = Gas constant (8.3143 J/mol K)
- \(t_{gel}\) = Gelling time (min)
- \(T\) = Temperature (K)
- \(x\) = Active matter content (% by volume).

The values for \(K_x\) and \(K_T\) at four temperatures are given in Table 6-8.

### Table 6-8. Values for \(K_x\) and \(K_T\) at Different Temperatures†

<table>
<thead>
<tr>
<th>Temperature (^\circ\text{F} [\text{K}])</th>
<th>(K_x)</th>
<th>(K_T) (min)</th>
</tr>
</thead>
<tbody>
<tr>
<td>104 [313]</td>
<td>-16.94</td>
<td>(e^{62})</td>
</tr>
<tr>
<td>140 [333]</td>
<td>-17.14</td>
<td>(e^{61})</td>
</tr>
<tr>
<td>176 [353]</td>
<td>-3.84</td>
<td>(e^{18})</td>
</tr>
<tr>
<td>266 [403]</td>
<td>-11.34</td>
<td>(e^{51})</td>
</tr>
</tbody>
</table>

† Vidick et al. (1988).

In cases in which the lost circulation zone is also a zone of interest, either for production or injection purposes, it may be necessary to design the plugging material for eventual removal during the completion of the well. Such removable systems are generally acid soluble, consisting of bridging agents slurried in a viscous fluid, crosslinked polymer plugs, or cementitious materials. Typical bridging materials include ground calcium carbonate particles with diameters ranging from 0.0003 in. \([8 \mu m]\) to 0.01 in. \([250 \mu m]\). They are used at concentrations up to 10 lbm \([4.5 \text{ kg}]/\text{bbl}\) of carrying fluid. Assuming a relatively homogeneous sandstone formation in which the sand grains are of similar size, it is possible to predict the required particle size of calcium carbonate to form a bridge in the pore throats of the formation matrix, thereby reducing the loss of fluid. These values are given in Table 6-6. Alternatively, one can use the IPT software described earlier in this chapter.

A borate crosslinked, xanthan-base polymer pill (Powell et al., 1991) also can act as a bridging material. Modified starch polymers are also added as fluid-loss additives. Further, sized borates are used for additional bridging to reduce losses while the plug sets. The crosslinking time can be controlled by using accelerators or retarders. The plug is acid soluble, more than 90% being dissolved on contact with a 15% HCl solution.

An acid-soluble cementitious product is Sorel cement, a mixture of magnesium oxide, magnesium chloride, and water (Chapter 7). Alsdorf and Dittmar (1987) pointed out that this type of cement is not applicable at elevated temperatures, because control of the setting time is difficult. They recommended the use of a material containing about 60% by weight of ground milk-of-lime grit, plus calcium or magnesium chloride and water. By varying the percentage of the calcium or magnesium chloride, it is possible to vary the thickening time from 1 to 4 hr at temperatures up to 185°F \([90^\circ\text{C}]\). The maximum compressive strength is obtained after 5 to 24 hr. The final product is completely soluble in 5% hydrochloric acid.

### 6-3.4.3 Downhole-mixed systems

Downhole-mixed systems consist of two or more fluids that, upon making contact in the wellbore or the lost circulation zone, form a viscous plug or a precipitate that seals the zone. It is common practice to prevent the mixing of the fluids until they are in front of the lost circulation zone, either by pumping a spacer or by pumping one fluid down the drillstring while the other fluid is simultaneously pumped down the annulus. These systems are not suitable for total lost circulation situations, in which the actual displacement rates are not known, because it is very difficult to control the mixing of the fluids.

For partial losses, Iljas (1983) found better success by using mud-diesel-oil-bentonite (M-DOB) plugs instead of LCMs. M-DOB plugs are a combination of diesel oil and bentonite and are sometimes called “gunk plugs.” When this mixture contacts water or WBM, it forms a mass with high gel strength. Soft, medium, and hard plugs may be formed by controlling the proportions of the ingredients. The M-DOB slurry is pumped down the drillpipe, and the mud down the annulus.

M-DOB plugs suffer from several drawbacks.

- They break down with time.
- They are difficult to apply in long openhole intervals.
- When losses are severe, it is impossible to achieve a reliable pumping rate down the annulus; therefore, the degree of mixing cannot be controlled.
- They develop no compressive strength.
Gaddis (1975) increased the gel strength of the M-DOB plug by blending a water-soluble polymer with the bentonite in diesel oil. On contact with water, the polymer hydrates, and the clay flocculates to form a stiff cement-like plug. For severe losses, Messenger (1981) and Iljas (1983) suggested a better version of the M-DOB plug—the mud-diesel-oil-bentonite-cement plug (M-DOB2C). The advantage of this system is the development of compressive strength. The ratios of mud and DOB2C required to produce mixtures of various hardnesses are shown in Table 6-9. Many downhole-mixed systems use a combination of two or more surface-mixed systems to provide an effective plugging material. For example, an M-DOB plug can be followed by a cement plug, thereby improving its strength and durability.

In 1972, Biles described a technique for sealing highly permeable channels. A sodium silicate solution is allowed to mix with a solution containing divalent cations, forming a precipitate. This technique successfully sealed permeable formations, but the precipitate was not sufficiently strong to seal naturally fractured formations. Russell (1983) refined this technique by employing a preflush of extended Portland cement slurry, followed by a sodium silicate solution and then a neat or thixotropic cement slurry. Both laboratory and field results showed a dramatic strength improvement when the sodium silicate and cement slurry intermixed. This was apparently caused by the high availability of calcium ions from the cement and the instantaneous dehydration of the cement slurry owing to the reaction.

Murphey (1983) proposed the use of potassium silicate instead of sodium silicate because the latter may tend to gel prematurely when mixed with brine. He described a common practice for solving total lost circulation in fractured and cavernous formations—pumping alternating batches of silicate and divalent cation solutions, with small freshwater spacers as separating fluids. The entire sequence is then followed by a Portland cement slurry.

Quinn et al. (1999) presented a novel shear-sensitive plugging fluid that can be pumped through the drill bit, curing losses instantly. The fluid is an invert emulsion. The continuous phase is a suspension of crosslinker particles in oil, and the internal phase contains a high concentration of polymer. As the emulsion passes through the bit nozzles, the pressure drop causes the emulsion to “flip” and exposes the polymer to the crosslinker (Fig. 6-14). The result is a rigid gel that can be designed to generate a solid structure from 1 to 10 min after passing through the bottomhole assembly.

This gelling mechanism ensures accurate placement at the loss zones and is more reliable than pills activated by downhole temperature or downhole fluid interaction. After placement, the set gel is stable for several weeks under downhole conditions, allowing sufficient time to drill and complete the section.

Cement can also be incorporated into the emulsion system. Such systems initially form a high-viscosity gel. The cement sets later, providing long-term lost circulation control.

Table 6-9. Hardness of Different Combinations of Mud with DOB2C†

<table>
<thead>
<tr>
<th>Mud</th>
<th>DOB2C</th>
<th>Hardness</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1</td>
<td>Soft</td>
</tr>
<tr>
<td>1</td>
<td>1.5</td>
<td>Medium</td>
</tr>
<tr>
<td>1</td>
<td>2</td>
<td>Medium hard</td>
</tr>
<tr>
<td>1</td>
<td>2.5</td>
<td>Hard</td>
</tr>
<tr>
<td>1</td>
<td>3</td>
<td>Very hard</td>
</tr>
</tbody>
</table>

† Iljas (1983).

![Fig. 6-14. Mechanism of invert emulsion system for curing lost circulation problems (from Quinn et al., 1999).](image-url)
6-3.5 Methods for controlling massive lost circulation

6-3.5.1 “Floating mudcap” method
The “floating mudcap” method can be used to complete a section in which massive losses are occurring. This method involves keeping the annulus full of weighted mud to control formation pressures while drilling ahead with water, which is continually lost to the formation. The density of the fluid in the annulus must be high enough to maintain well control, but not so high that the fluid induces further losses. If possible, the casing should be set just above the loss zone, because this makes control of the mudcap considerably easier. Because of the safety implications and potential loss of well control, it is necessary to use well-trained and experienced rig crews for this relatively risky method.

6-3.5.2 Drilling “blind”
When caverns are too large to realistically fill with mud or seal off, an established practice is to continue drilling until competent beds are encountered and then to set the casing. This procedure is commonly known as “drilling blind.”

6-3.5.3 Using specialized drilling fluids
6-3.5.3.1 Foamed and aerated mud systems
Foamed muds (Kuru et al., 1999) and foamed cement can be applied successfully in massive loss situations. However, foams should only be used where formation pressures are low and the formation is competent, because there is little fluid pressure to support the wellbore wall.

Another technique uses “microbubbles” (Growcock et al., 2004) that are noncoalescing and can be recirculated. These unusual bubbles, called “aphrons,” are made to occur within the mud system without injecting external air or gas. Aphrons exist as independent spheres with a gas or air core encapsulated by a multiple-layer film. This film is the key to maintaining the bubble strength that allows aphrons to function as a bridging agent. A surfactant is used to form the aphrons, build the multilayer bubble walls, and create interfacial tension to bind the aphrons into a network capable of creating downhole bridging.

6-3.5.3.2 Mixed metal hydroxide and mixed metal oxide systems
Mixed metal hydroxides (MMH) are synthetic inorganic compounds designed to be electron deficient with a high aspect ratio (i.e., narrow edge and high surface area on the face) (Burba et al., 1988). Furthermore, the MMH crystals are manufactured to be smaller than a typical bentonite platelet. When the MMH and bentonite are mixed in an aqueous medium, a strong association occurs. This results in a mud with exceptional suspension abilities (Fig. 6-15). Such muds can also prevent and cure circulating losses. Good results have been achieved in areas where other methods to control lost circulation have failed (Fraser and Aragão, 2001).

Fig. 6-15. Suspension performance of drilling fluid containing mixed metal hydroxide.

Mixed metal oxide (MMO) systems are the successor to mixed metal hydroxides (Santarelli et al., 1992) and mixed metal oxide and hydroxide (MMOOH) systems. Electrostatic interactions between bentonite platelets with negative faces and MMO crystals with positive charges lead to a network of bentonite/MMO complexes that imparts a thixotropic nature to the fluid (Fig. 6-16).

An MMO crystal is 10 times smaller than a bentonite platelet, and has 6 to 7 times its charge density. MMO systems operate under the same principles as their predecessors but are more cost-effective than either MMH or MMOOH systems.
6-3.6 Lost circulation during cementing

Before initiating a conventional primary cementing operation, any lost circulation problem should be eliminated or significantly reduced by the techniques described above. If this is not possible, or if losses are anticipated during the primary cementing job, there are two options for remediation, as described by Nayberg and Linafelter (1984). The first is to maintain the downhole pressure during the job below the maximum equivalent mud circulating density by reducing the density of the cement slurry, minimizing the height of the cement column, or limiting the casing and annular friction pressures during the placement of the cement slurry. The second option is to pump a plugging material as a spacer in front of the cement slurry, add LCMs to the cement slurry itself, or use special additives that impart thixotropic properties to the cement slurry. The third option is to use a combination of techniques, which is often necessary when trying to prevent cement losses to highly fractured or vugular formations.

6-3.6.1 Downhole pressure reduction

Computer simulators can calculate the estimated downhole pressures at any particular depth in the well and at any time during the cementing operation (Chapter 12). This enables the operator to know (for a particular well completion) exactly which cement-slurry parameters and job procedures are required to prevent lost circulation and maintain adequate hydrostatic pressure in front of permeable zones. The most relevant parameter is the cement-slurry density, which may be reduced by adding one or more cement extenders. Chapter 3 provides a detailed discussion of extenders and the optimal slurry-density range for each.

The rheological properties of cement slurries may also be adjusted to reduce friction pressures during placement. This is especially critical in narrow annuli in which viscous slurries can cause very high friction pressures. Another technique mentioned by Nayberg and Linafelter (1984) is to lighten the hydrostatic column above the top of the cement by injecting nitrogen into the mud.

The downhole pressures exerted on lost circulation zones can also be decreased by using mechanical devices such as stage collars or external casing packers (ECPs). Stage collars permit the casing string to be cemented in two or three stages, lowering the dynamic and hydrostatic pressures (Chapters 11 and 12).

To reduce the risk of cement fallback if losses do occur, a special stage collar with a packoff adaptation can be used. When expanded, this stage collar provides a seal between the casing and the formation to prevent downward fluid movement. Cement baskets can also be placed just below the stage collar to provide the same effect. Turki and Mackay (1983) described the placement of ECPs immediately above the lost circulation zone to reduce the hydrostatic pressure. A typical application would be a two-stage job with an ECP just above the lost circulation zone and a stage collar just above the ECP. After the first stage is performed, the ECP is expanded to seal the annulus, preventing the transmission of hydrostatic pressure to lower zones (Fig. 6-17).

However, if the size of the hole is larger than anticipated, the ECP may fail to provide a perfect seal because of insufficient lateral expansion.

Turki and Mackay (1983) also mentioned the “hydrostatic cementing technique” for attempting to obtain zonal isolation across cavernous lost circulation zones. A conventional first-stage job is performed, followed by pumping a predetermined quantity of cement slurry down the annulus. Most of the slurry is lost to the cavernous formation. However, after the hydrostatic pressure of the cement slurry equilibrates with the formation pressure of the lost circulation zone, a portion will remain in the annulus. When the cement sets, the cavern is bridged, and cement exists at some height above the cavern. The application of this technique was recommended only when lost circulation cannot be significantly reduced by conventional means or when open holes are excessively washed out.
6-3.6.2 Preflushes

Murphey (1983) described the use of a potassium silicate solution as a preflush to enable the formation to support a greater than normal hydrostatic pressure. The preflush penetrates the highly permeable formations, permitting contact with calcium ions in the formation and resulting in the formation of a gel. If insufficient calcium ions are present in the formation, a second preflush of a calcium chloride solution can be pumped. The high concentration of calcium ions in the cement slurry ensures immediate sealing of the formation.

6-3.6.3 LCMs for cement slurries

Nayberg and Petty (1986) and Turki and Mackay (1983) agreed that the effectiveness of LCMs in cement slurries is limited to minor or partial losses in highly permeable formations, and that they are not for solving total lost circulation in naturally fractured or cavernous formations. When LCMs are used in the cement slurry, care must be taken to ensure that the materials are inert to the cement composition. Also, the size and concentration of the materials should be selected to avoid bridging or plugging of the downhole equipment. The morphologies of the materials are the same as those used in drilling fluids. The authors are not aware of any reported use of encapsulated additives in cement slurries for solving lost circulation problems. Table 6-10 is a list of LCMs for cement slurries, their properties, and typical effective concentrations. These LCMs are also described in Chapter 3.

The most common LCMs for cement slurries are of the granular type, designed to bridge at the formation face or within the matrix. Gilsonite, a naturally occurring asphaltine hydrocarbon with a particle size in the range 8–60 mesh, is widely used. Gilsonite is not suitable for high-temperature applications because of its low melting point (220°F [104°C]). Crushed coal, with a standard mesh size in the range 14–200 and a melting point of approximately 1,000°F [538°C], is applied in the same manner as gilsonite, and can be used in high-temperature wells. Shells from walnuts, pecans, and other

Table 6-10. Materials Commonly Added to Cement Slurries to Control Lost Circulation

<table>
<thead>
<tr>
<th>Type</th>
<th>Material</th>
<th>Nature of Particles</th>
<th>Amount Used</th>
<th>Water Required</th>
</tr>
</thead>
<tbody>
<tr>
<td>Granular</td>
<td>Gilsonite</td>
<td>Graded</td>
<td>5 to 50 lbm/sk</td>
<td>2 gal/50 lbm</td>
</tr>
<tr>
<td></td>
<td>Perlite</td>
<td>Expanded</td>
<td>⅛ to 1 ft³/sk</td>
<td>4 gal/ft³</td>
</tr>
<tr>
<td></td>
<td>Walnut shells</td>
<td>Graded</td>
<td>1 to 5 lbm/sk</td>
<td>0.85 gal/50 lbm</td>
</tr>
<tr>
<td></td>
<td>Coal</td>
<td>Graded</td>
<td>1 to 10 lbm/sk</td>
<td>2 gal/50 lbm</td>
</tr>
<tr>
<td>Lamellar</td>
<td>Cellophane flake</td>
<td>Flaked</td>
<td>⅛ to 2 lbm/sk</td>
<td>none</td>
</tr>
<tr>
<td>Fibrous</td>
<td>Nylon</td>
<td>Short fibers</td>
<td>⅛ to ¼ lbm/sk</td>
<td>none</td>
</tr>
<tr>
<td></td>
<td>Glass</td>
<td>Long fibers</td>
<td>2 to 3 lbm/sk</td>
<td>none</td>
</tr>
</tbody>
</table>

Fig. 6-17. Cementation using an ECP.
nuts are also available in fine, medium, and coarse grades; however, care should be exercised at concentrations above 4 lbm/sk to avoid the plugging of downhole equipment.

Cellophane flakes with diameters of 3⁄8 to 3⁄4 in. [9.5 to 19 mm] are the most common flake material. At concentrations above 2 lbm/sk, bulk loading and mixing of the cement slurry becomes extremely difficult.

Nylon and polypropylene fibers have been used as LCMs in cement slurries. As the cement slurry enters the lost circulation zone, the fibers associate to form a mat that promotes cement filtercake development. However, their use has been limited by problems of mixing them into cement slurries and their tendency to plug pump plungers and float equipment. Very often, the fibers are seen floating on the slurry surface and forming “fur balls.”

More recently, silica-base fibers have been developed as LCMs for cement slurries. As the cement slurry enters the lost circulation zone, the fibers associate to form a mat that promotes cement filtercake development. However, their use has been limited by problems of mixing them into cement slurries and their tendency to plug pump plungers and float equipment. Very often, the fibers are seen floating on the slurry surface and forming “fur balls.”

6-3.6.4 Thixotropic cement systems
The self-supporting property of thixotropic cements is useful across formations with low fracture gradients. When ordinary slurries pass over a weak zone, the increase in hydrostatic pressure can cause formation breakdown. As a result, the top of the cement falls to a point below the desired level of fill-up. Thixotropic slurries do not fall back because some of the hydrostatic pressure is transmitted to the formation face and casing walls. Several thixotropic cement compositions exist, and their chemistries are described in Chapter 7.

6-3.6.5 Foamed cement systems
Owing to their low density, foamed cement systems are often used as an alternative to conventional cement systems to solve lost circulation problems (Nayberg and Petty, 1986). The design and application of foamed cement is discussed thoroughly in Chapter 7.

6-3.7 Lost circulation design software
An innovative software program (Bruton et al., 2004) has been developed to assess operator and well-specific lost circulation problems and link them to available solutions. The software tool focuses on existing resources, such as lost circulation products, procedures, geomechanical models, logs, and mineralogy/geology analyses to create project-specific plans and solutions.

The software contains four key modules designed to (a) consider well-specific data, (b) determine the most likely thief zones, (c) locate the position of potential thief zones relative to key depths of interest, such as the casing/liner shoe, and (d) identify the most appropriate preventative and treatment measures (Fig. 6-19). The goal is to minimize and prevent lost circulation problems rather than develop an after-the-fact cure. The integrative preplanning process analyzes offset well histories and formation data to identify risk zones and also gathers information on the exact fracture and pore size as well as fracture density. Afterward, detailed interval-specific solutions are developed for stopping losses encountered while drilling or tripping in.

Fig. 6-18. Photographs of silica-fiber “tows” (left) and a dispersed-fiber network (right).
6-3.8 Lost circulation—conclusions

Lost circulation problems, whether during drilling or cementing, can be solved if the correct technique is applied for each individual case. Choosing the correct solution from the wide variety of available remedies described above can be a difficult task; however, certain general guidelines can be followed. Messenger (1981) summarized the most important factors to consider.

- The location of the loss zone must be determined accurately; otherwise, the remedy will be placed in the wrong zone. Many loss zones thought to be at the bit are actually farther up the hole at the first point of loss.
- LCMs and techniques must be systematically matched to the type and severity of the loss zone. For example, using LCMs in the drilling mud to stop total losses to a vugular limestone will almost never work. One has a much better chance for success with a combination of surface- and downhole-mixed systems with low densities, thixotropic behavior, and good strength development.

Fig. 6-19. The four key modules of the lost-circulation software.
Consulting records of prior experience with lost circulation in a particular field often points the way to an effective solution.

Above all, careful prejob planning can prevent the occurrence of lost circulation. It is important to obtain, if possible, sufficient well information to perform a computer simulation of the cement job (Chapter 12).

6-4 Cement-formation bonding

The ability of a cement sheath to provide zonal isolation is directly related to the following properties:

- the cement/casing interface
- the bulk cement
- the cement/formation interface.

Cementing recommendations are frequently based on the compressive or tensile strength of set cement, and many governmental regulatory bodies impose minimum strength requirements for well cements. The assumption is that a material satisfying certain strength requirements will provide an adequate bond to the casing and formation. However, field and laboratory experience has shown that this assumption is not always valid.

In a wellbore, shear bond and hydraulic bond are two criteria often considered for effective zonal isolation along the cement/casing and cement/formation interfaces. Shear bonding mechanically supports the pipe in the hole and is determined by measuring the force required to initiate pipe movement in a cement sheath (Fig. 6-20). This force, divided by the cement/casing contact surface area, yields the shear-bond strength.

Hydraulic bonding blocks the migration of fluids in a cemented annulus. It is usually measured by applying pressure at the pipe/cement or pipe/formation interface until leakage occurs (Fig. 6-21). For zonal isolation, hydraulic bonding is more important than shear bonding.

In 1961, Evans and Carter published the results of an extensive study that investigated shear and hydraulic bonding of cement systems to casings and formations. A variety of Portland cement systems was tested that contained various additives such as pozzolanic extenders, bentonite, retarders, and fluid-loss additives. Latex-modified cements and resin cements were also tested. The formation materials were sandstone and limestone. Evans and Carter also evaluated the effects of mud films and filtercakes on the bond strength. A detailed discussion of their work is beyond the scope of this chapter; however, the major findings are summarized in the following discussion.

More recently, work has been performed by Ladva et al. (2004) to better characterize the cement-formation bond. Instead of working with sandstone and limestone, Ladva et al. concentrated on formations that contain unstable clay minerals. Such formations have long been known to be the most problematic during well construction, particularly drilling.

This section first presents a background discussion of the cement/casing bond, then moves on to the subject at hand: the cement-to-formation bond. The Evans and Carter work with sandstones and limestones is discussed first, followed by the Ladva et al. study with clay-bearing formations. The section concludes with a discussion of work performed in the civil-engineering industry to determine how Portland cement slurries interact and bond with formations.
6-4.1 Cement-to-casing bonding
The shear-bond tests performed by Evans and Carter investigated the effects of pressure, pipe finishes (e.g., mill varnishes), uncoated pipes (wire-brushed, rusty and sand blasted), and WBM and OBM.

Evans and Carter found a correlation between cement compressive strength and the shear-bond strength. The data, shown in Fig. 6-22, were generated after the cement slurry had been set against clean, dry pipe with no internal pressure applied inside the pipe during the setting process. Significant shear-bond-strength variations were observed when the test conditions deviated from this ideal.

The effects of pipe-surface finish variations, as well as pipe wetting with WBM and OBM, are shown in Table 6-11. A loss of shear-bond strength was readily noticeable when a thin sheath of mud was present at the pipe-cement interface. OBM was more detrimental to the cement bond than the WBM. Lower bond strengths were measured with new pipe coated with mill varnish. Higher bond strengths were observed when the pipe surface was roughened by rust, wire brushing, or sandblasting.
Pressurizing the casing during the setting process is detrimental to the shear bond. The loss of bond strength is a function of the pressure and the pressurization time (Fig. 6-23).

The effect of drilling mud on hydraulic-bond strength to pipe was investigated. As shown in Table 6-11, the hydraulic bond was reduced by the mud coating. Unlike the shear-bond strength, the hydraulic bond strength improved when the curing was performed under pressure (Table 6-12).

### Table 6-11a. Bonding Properties of New and Used Pipe†, ‡

<table>
<thead>
<tr>
<th>Casing Type</th>
<th>Time (days)</th>
<th>Hydraulic Bond (psi)</th>
<th>Shear Bond (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>New</td>
<td>8 hr</td>
<td>–</td>
<td>10</td>
</tr>
<tr>
<td>Used (rusted)</td>
<td>8 hr</td>
<td>–</td>
<td>53</td>
</tr>
<tr>
<td>New</td>
<td>1</td>
<td>300</td>
<td>79</td>
</tr>
<tr>
<td>New (sandblasted)</td>
<td>1</td>
<td>500</td>
<td>123</td>
</tr>
<tr>
<td>Used (slightly rusty)</td>
<td>2</td>
<td>500–700</td>
<td>182</td>
</tr>
<tr>
<td>Used (sandblasted)</td>
<td>2</td>
<td>500–700</td>
<td>395</td>
</tr>
<tr>
<td>Used (rusted)</td>
<td>2</td>
<td>500–700</td>
<td>422</td>
</tr>
</tbody>
</table>

‡ API Class A cement cured at 80°F; casing size of 2 in. inside 4 in.; cement sheath of 0.812 in.

### Table 6-11b. Effect of Mud Type on Bonding Properties of New and Used Pipe†, ‡

<table>
<thead>
<tr>
<th>Mud Type</th>
<th>Time (days)</th>
<th>Hydraulic Bond (psi)</th>
<th>Shear Bond (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>New Pipe</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Water-base mud</td>
<td>2</td>
<td>175–225</td>
<td>46</td>
</tr>
<tr>
<td>Dry</td>
<td>2</td>
<td>375–425</td>
<td>284</td>
</tr>
<tr>
<td>Used (Slightly Rusty) Pipe</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil-base mud</td>
<td>2</td>
<td>–</td>
<td>75</td>
</tr>
<tr>
<td>Water-base mud</td>
<td>2</td>
<td>–</td>
<td>174</td>
</tr>
<tr>
<td>Dry</td>
<td>2</td>
<td>–</td>
<td>182</td>
</tr>
</tbody>
</table>

‡ API Class A cement cured at 80°F; casing size of 2 in. inside 4 in.; cement sheath of 0.812 in.

### Table 6-12. Effect of Curing Temperature and Pressure on Hydraulic-Bond Strength to Pipe†, ‡

<table>
<thead>
<tr>
<th>Curing Conditions</th>
<th>Time (days)</th>
<th>Temperature (°F)</th>
<th>Pressure (psi)</th>
<th>Failure Pressure (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>24</td>
<td>80</td>
<td>0</td>
<td>500</td>
</tr>
<tr>
<td></td>
<td>48</td>
<td>80</td>
<td>0</td>
<td>500</td>
</tr>
<tr>
<td></td>
<td>24</td>
<td>120</td>
<td>0</td>
<td>500</td>
</tr>
<tr>
<td></td>
<td>24</td>
<td>140</td>
<td>2,000</td>
<td>600</td>
</tr>
<tr>
<td></td>
<td>24</td>
<td>120</td>
<td>3,000</td>
<td>800</td>
</tr>
<tr>
<td></td>
<td>24</td>
<td>80</td>
<td>0</td>
<td>600</td>
</tr>
</tbody>
</table>

‡ The cement is API Class A; the pipe was 2-in. diameter inside 4-in. diameter and 10-in. long.
6-4.2 Cement-to-formation bonding (sandstone and limestone)

Evans and Carter used Indiana limestone and Berea sandstone to evaluate the shear and hydraulic pressure necessary to break the bond between the cement/formation interface. The permeability of the Indiana limestone was 1 mD, and that of the sandstone was 100 mD.

Figure 6-24 shows the shear-bond strength, compressive strength, and hydraulic-bond strength measured for six cement systems placed against dry limestone cores. The sandstone results were not shown because failure occurred within the core rather than at the bonded interface.

The next four plots contain data collected after the cores had first been exposed to a water-base drilling mud. The cement slurry was either squeezed against the formation core at a pressure of 100 psi [4.8 kPa] or allowed to set unpressurized. The mud filtercake was either removed from the formation face or allowed to rest undisturbed.

Figure 6-25 shows the results when the formation walls were cleaned and the cement was squeezed. Despite the cleaning of the formation walls, the shear and hydraulic bond strengths are lower than those shown in Fig. 6-24.

Figure 6-26 shows the results when the formation walls were cleaned but the cement was squeezed. Comparison of these results with those in Fig. 6-25 reveals that squeezing generally has a beneficial effect on the bond strengths. The notable exception is the resin cement. Because the resin cement had no solids to deposit as a filtercake, it is logical that squeezing would have little effect.

Figures 6-27 and 6-28 show the same comparison as Figs. 6-25 and 6-26, with the exception that a thin layer of mud was left on the walls of the test chamber. A reduction in bond strength was noted when mud was left on the walls, even though the compressive strength of the cement was the same.

Figures 6-25 through 6-28 also show that higher hydraulic-bond strengths were obtained against the less-dense sandstone formation. The reason for this is that cement slurry can be dehydrated more efficiently against a more permeable formation, resulting in a higher-strength cement.

As discussed earlier, clay-bearing formations are more problematic during the well construction process. The work of Evans and Carter did not address such formations. The remainder of this section is devoted to work with clay-bearing formations, notably shales. The discussion begins with a short review of clays, followed by information about how various drilling fluids and cement slurries interact with shales. Finally, related research performed in the civil engineering industry is presented.

![Fig. 6-24. Bonding properties of cement to dry limestone (from Evans and Carter, 1961). Reproduced courtesy of the American Petroleum Institute.](image-url)
Fig. 6-25. Bonding properties of cement to formation with cement squeezed and walls cleaned (from Evans and Carter, 1961). Reproduced courtesy of the American Petroleum Institute.

Fig. 6-26. Bonding properties of cement to formation with cement not squeezed and walls cleaned (from Evans and Carter, 1961). Reproduced courtesy of the American Petroleum Institute.
6-4.3 Properties of clays

Seventy percent of footage drilled while constructing a wellbore is through shale, a type of rock that contains clay minerals. Clay is a rock term and, like most rocks, it is composed of a number of different minerals in varying proportions. Clays are all essentially hydrous magnesium or aluminum silicates. Although a clay may consist of a single clay mineral, there are usually several mixed with other minerals such as feldspar, quartz, carbonates, and micas.
Clay minerals belong to the group of silicate minerals known as phyllosilicates. In phyllosilicates, the SiO₄ tetrahedra are arranged in sheets such that the Si/O ratio is 2:5. This structural unit is sometimes called the “siloxane sheet” (Figure 6-29).

The siloxane sheet is not electrically neutral and cannot form a stable structure alone. To balance the charges, the siloxane sheets combine with sheets of hydroxyl ions (OH⁻) coordinated by magnesium ions (forming brucite) or aluminum ions (forming gibbsite). The resulting structures are very open, allowing other species (e.g., iron, potassium, and sodium) to substitute for magnesium or aluminum. The properties of clays depend on how the various sheets are arranged and the nature of the ionic substitutions.

Owing to their open structure, clays are sensitive to contact with foreign fluids containing electrolytes. To maximize stability from both a structural and electrical point of view, a clay will exchange anions and cations with the electrolyte (Swartzen-Allen and Matijevic, 1974). The clay is then said to have a certain cation exchange capacity, usually quoted as the number of chemical equivalents per unit weight of dry clay.

Among the most sensitive clays are those of the smectite group. A structural diagram is shown in Fig. 6-30. Molecular water containing free cations is sandwiched between two Si₂O₅–Al₂(OH)₆–SiO₅ layers. The essentially uncharged layers may expand in this way to unusually large cell dimensions; consequently, the minerals of this group show unrivalled capacity for swelling when wetted. One of the most common smectite minerals is montmorillonite (bentonite contains mainly montmorillonite) (Chapter 3), used as an extender and/or thickener in drilling fluids and cement slurries.

The negatively charged clay surfaces do not have an equal affinity for all cations but exhibit selectivity depending on such factors as ionic charge, ionic size, and state of hydration. The order of increased affinity for the alkali metal ions is Li⁺ < Na⁺ < K⁺ < Rb⁺ < Cs⁺. For the alkaline earth ions, the order is Mg²⁺ < Ca²⁺ < Sr²⁺ < Ba²⁺. In general, cations that are least preferred by the surface (such as Na) are associated with limited particle aggregation and extensive swelling, while strongly bound ions (such as K⁺) promote extensive aggregation and limited swelling. Organic anions and cations can also influence stability.

The adsorption of water by clays can occur either by hydration of the crystal surfaces or hydration of the exchange cations. Some values for the cations found in natural montmorillonites are given in Table 6-13.

Sedimentary rocks such as shales are formed when ocean floor sediments are buried and subjected to overburden pressures and moderately high temperatures (Pettijohn, 1975). The composition of shales is varied, because these deepwater sediments are formed by abrasion processes (mainly silt), weathering (residual clays),
and chemical and biochemical additions. Shales can contain as much as 40 wt% of clays and are sometimes classified as shales or mudstones depending on the orientation of the clay minerals. Shales are highly oriented, whereas mudrocks are randomly oriented. As burial depth increases, the abundance of less-reactive clays (illite and kaolinite) increases and that of the montmorillonite clays such as smectite decreases. A typical shale does not exist, although shales are sometimes classified from soft to brittle as the smectite content decreases (Weaver, 1989).

### 6-4.4 Interactions between drilling fluids and shales

During the well-construction process, the rock formations are exposed to drilling fluids. The drilling fluids can interact with the surfaces of clay-bearing formations and alter their water content and permeability.

Erosion of the wellbore wall during the drilling process is prevented by careful drilling fluid selection. Drilling fluids fall into two main categories—water-base and oil-base. The water-base systems can contain polymers such as acrylamides and glycols or silicates. In some cases the degree of clay swelling can be reduced by the addition of salts. These water-base fluids work by adsorbing organic compounds onto the clay surfaces or by the formation of osmotic membranes.

Sherwood and Bailey (1994) investigated the depth of invasion of water from a viscosified KCl solution (=0.5 M) into predrained Oxford shale cores. The ingress was of the order of 10 mm after a 48-hr circulation period, resulting in a layer of swollen shale on the surface of the laboratory-scale wellbore. At present, it is not known if such a layer would remain on the wellbore wall during the cementing stage. During a primary cementing operation, a spacer or wash fluid is frequently used to separate the drilling fluid and the cement slurry and to make the formation surface receptive to bonding with cement. Nevertheless, it would be prudent to assume that the shale in the near-wellbore region is more permeable than the far-field shale.

Shale has the capacity to limit the movement of charged species through its pores but not stop their movement completely (Schlemmer et al., 2003). Silicate muds and OBM can enhance the ability of shale to exclude ions, forming osmotic membranes on the shale surface or close to the wellbore wall (Mody et al., 2002; Bol et al., 1994). By setting the water activity in the drilling fluid lower than that of the shale, silicate or oil-based drilling fluids can dewater shale. Consequently, the near-wellbore region is less porous and permeable than the far-field shale. For silicates, this effect is enhanced by the deposition of silicate precipitates. A silicate-base fluid reduces the permeability of the shale to ions and water (Bailey et al., 1998; Van Oort et al., 1996). The silicate fluid works by converting sodium silicate to calcium silicate, or by precipitation of polymeric silicates as the pH drops below 10 at the shale surface.

In the wellbore, shales are often in contact with drilling fluids for several days before cementing. Ladva et al. (2004) pretreated Oxford shale cores with various types of drilling fluids. It can be seen in Fig. 6-31 that the shale cores swell in the partially hydrolyzed polyacrylamide (HPA) and a low inhibitive glycol fluid (polyethylene glycol or KCl) and shrink in the silicate-based and OBM fluids. This behavior is connected to the water activities of the muds, which are greater than 0.95 for the HPA and glycol mud but 0.83 for the silicate and OBM systems.

The authors found no detailed studies in the literature that discuss the quality of primary cementing jobs after using specific drilling fluids. However, some papers do allude to increased success of primary cementing jobs after using silicate drilling fluids (Cardno et al., 1997). The advantage of silicate mud over polymer mud for primary cementing was described in a study of the Lennox field, Liverpool Bay. The silicate system appeared to improve hole gauge sufficiently to allow good primary cementing on the 9 5/8-in. section without the problem of gas migration. However, no detailed scientific study was performed to confirm the incorporation of silicate from the drilling fluid into the cement matrix. A patent by Mondshine (1977) proposes pretreating the wellbore with a silicate fluid. However, there is no conclusive evidence of improved bonding. There is also some evidence provided by Dillenbeck and Nelson (1992) that cement slurries containing potassium salts or amines are useful in front of shale sections.

<table>
<thead>
<tr>
<th>Ion</th>
<th>Dehydrated Ion Diameter (Å)</th>
<th>Charge Density (charge/Å²)</th>
<th>Hydrated Ion Diameter (Å)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sodium (Na+)</td>
<td>1.90</td>
<td>0.088</td>
<td>11.2</td>
</tr>
<tr>
<td>Potassium (K+)</td>
<td>2.66</td>
<td>0.045</td>
<td>7.6</td>
</tr>
<tr>
<td>Magnesium (Mg²⁺)</td>
<td>1.30</td>
<td>0.376</td>
<td>21.6</td>
</tr>
<tr>
<td>Calcium (Ca²⁺)</td>
<td>1.90</td>
<td>0.176</td>
<td>19.0</td>
</tr>
</tbody>
</table>

6-4.5 Interactions between cement slurries and shales

Filtration of cement filtrate into shale sections can lead to further disturbance of the shale. The extent of wellbore-wall damage is largely controlled by the following factors:

- initial hydrostatic pressure relative to the shale pore pressure
- initial water activity in the cement slurry relative to that in the shale pore.

Once the cement has set and the internal pore pressure has dropped, a positive suction pressure is possible, drawing water from the swollen shale back into the cement.

As discussed in Chapter 2, Portland cement hydration is an exothermic process. When the temperature-profile maxima are reached and the cement slurry begins to set, the internal pore pressure begins to drop. Along with the pore-pressure reduction, internal shrinkage occurs. Such shrinkage can cause problems such as wellbore microannuli and annular fluid migration (Chapter 9). It is important to note at this stage that the extent of the pore-pressure drop depends on the external supply of water to the cement slurry. Appleby and Wilson (1996) examined the pore-pressure decrease with and without access to excess fluid, as shown in Fig. 6-32, where valve open and valve closed represent the presence and absence of excess water. This ability of cement to dewater adjacent surfaces without altering its external dimensions could lead to debonding at a shale or filtercake surface.

Cement hydration is a dissolution-precipitation process. Ions are available in solution before they are incorporated into the hydration products. Table 6-14 shows the solution concentration of certain ionic species after 20 min of hydration (Michaux et al., 1989a and 1989b).
A simple approximation, such as that shown in Eq. 6-20, can be used to estimate the water activity, \( a_w \), in a cement slurry containing single (\( u \)) and complex (\( m \)) species.

\[
\ln a_w = -0.018K_{os} \left( \sum \sum j u + \sum j m \right) \tag{6-20}
\]

Assuming an osmotic coefficient (\( K_{os} \)) of 1, the calculated solution water activity is 0.98 after 20 min of hydration and 0.96 after 3 hr of hydration at 25°C. These approximate calculations agree with those carried out by van Breugel (1992). In fact, van Breugel suggests that the water activity in the interfacial transition zone (100 \( \mu \)m) between an aggregate and cement remains high for at least 10 hr after mixing. This high water activity, coupled with hydrostatic pressure, will increase the ingress of fluid into shale sections during well construction (Heathman et al., 2003).

The potential for shales to swell when exposed to a cement slurry was studied by Ladva et al. (2004). Unconfined linear swelling tests were performed with two shales: Oxford shale (17 wt% smectite) and Catoosa shale (6 wt% smectite). As discussed earlier, smectite readily swells in the presence of water. After exposure to a synthetic cement filtrate with the composition shown in Table 6-14, the Oxford shale swelled more than the Catoosa shale (Fig. 6-33).

Ladva et al. (2004) also performed shear-bond or push-out tests between a neat 15.8 lbm/gal Class G cement and the Oxford and Catoosa shales. A cell was designed to measure the shear-bond strength between the shale core or filtercake and set cement (Fig. 6-34). A freshly cored shale plug with a diameter of 1 in. [25.4 mm] and a nominal length of 0.8 in. [20 mm] was placed centrally on the acrylic plastic base. An acrylic plastic spacer was then placed on top of the shale core, and the cement slurry was poured around the shale to the top of the spacer.

The acrylic plastic lid and base were sealed to the polytetrafluoroethylene (PTFE) cell walls using silicone rubber on the outer surface. After the curing period, the base, lid, and acrylic plastic spacer were removed. The cell walls and cement ring were supported while a brass rod (0.8 in. [20 mm] in diameter) was used to load the shale core. The maximum force required to push out the shale at a rate of 0.5 mm/min was measured. The shear-bond strength was calculated by dividing the maximum force by the area of the shale/cement interface.

A typical shear test profile, presented in Fig. 6-35, shows the maximum load that the interface could withstand before rupturing. After 8 days curing at 185°F [85°C], the shear-bond strength was 79.8 lbf/in\(^2\) [0.55 MPa]. During the shear-bond test, the untreated Oxford shale core was pushed out of the cement ring, but a film of shale remained on the inside of the cement. This suggests that the shear-bond strength of the shale/cement interface was greater than the shear strength of the shale itself.

### Table 6-14. The Ionic Strength in Solution After 20 min of Cement Hydration at 77°F [25°C]

<table>
<thead>
<tr>
<th>Species</th>
<th>Concentration (mmol/L)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ca(^{2+})</td>
<td>21.1</td>
</tr>
<tr>
<td>Na(^+)</td>
<td>117</td>
</tr>
<tr>
<td>K(^+)</td>
<td>422</td>
</tr>
<tr>
<td>SO(_4^{2-})</td>
<td>201</td>
</tr>
<tr>
<td>OH(^-)</td>
<td>168</td>
</tr>
<tr>
<td>Cl(^-)</td>
<td>6</td>
</tr>
<tr>
<td>pH</td>
<td>13.10</td>
</tr>
</tbody>
</table>

![Swelling of shale cores in synthetic cement filtrate.](image1)

![A schematic drawing of the shear-bond (push-out) testing cell.](image2)
The adhesion of Catoosa shale or Oxford shale to cement cured for 24 hr at 20°C was not measured because the sample fell apart at the interface on handling.

### 6.4.6 Bonding between cements and shales treated with various drilling fluids

In another set of experiments, Ladva et al. (2004) used a small wellbore simulator (SWBS) that allows rocks to be exposed to flowing drilling fluid under pressure. The simulator is depicted in Fig. 6-36. The rock sample has a diameter of 6 in. [150 mm] and a length of 8 in. [200 mm]. Along the axis of the rock is a predrilled central wellbore that is 1 in. [25.4 mm] in diameter. The rock sample is contained within a steel pressure vessel that operates at a pressure of 4,570 psi [31.5 MPa]. The outer cylindrical surface of the rock is surrounded by a rubber sleeve through which a radial confining stress may be applied. The top platen supplies the overburden pressure. Temperatures up to 176°F [80°C] can be maintained while operating under pressure. Drilling fluid is circulated down the central wellbore under pressure. After the drilling-fluid exposure, cement can be set under an applied pressure that is independent of the overburden pressure on the rock.

The experimental sequence consisted of the following steps:
- An Oxford shale core is drained at 1,450 psi [10 MPa] for 120 hr and moved to the wellbore simulator.
- An homogeneous stress of 10 MPa is applied with mud flow at a temperature of 68°F [20°C] for 48 hr.
- The sample is depressurized, the mud is removed, a cement slurry is added, and the core is represurized at 10 MPa and 167°F [75°C] for 120 hr.
- At the end of this period, the core is depressurized over a period of 1 hr.
- The core is removed from the cell, allowing one to observe the cement/shale interface and perform measurements.

In the SWBS, Oxford clay was treated with various drilling fluids for 48 hr. The drilling fluids were typical silicate muds and low inhibitive glycol muds. After setting cement against the pretreated shales, postmortem analyses were performed. The analyses showed that the water content of the shale at the cement interface was greater when the sample was pretreated with low inhibitive glycol mud than with a silicate mud. Thus, the effect of drilling fluids on the water content of the near-wellbore region persists after cementing. Also, when the shale was pretreated with silicate mud, the failure occurred at the cement-shale interface. Failure occurred in the shale itself when the glycol mud was used and when there was no pretreatment.
In small-scale push-out tests, the position of the failure plane also varied with the drilling fluid pretreatment (72 hr). However, pretreatment with drilling fluid did not substantially increase the shear-bond strength. Results from such tests are presented in Fig. 6-37.

![Diagram](image)

**Fig. 6-37.** Shear-bond measurements of interface between cement and Oxford shale treated with various drilling fluids.

### 6-4.7 Cement-to-formation bonding studies performed outside of the petroleum industry

Ideally, samples of set cement and the adjacent formation should be recovered from oil wells. Recovery would give us a better understanding of the chemical nature of the interface under downhole conditions during the lifetime of the well. In view of the lack of such samples, it is interesting to examine studies from the nuclear and construction industries.

There are other situations in which cement or alkaline fluids are in contact with clays, namely, in construction cements, nuclear waste sites, and a few naturally occurring repositories. At present, two lines of research exist. In one, preset plugs of cement are inserted into boreholes drilled in clay formations. In the other, clay crystals are treated with alkaline fluids at elevated temperature. These studies are an important source of information when trying to predict and modify the condition of the cement-rock interface in a wellbore over time.

For disposal, low-level radioactive waste is sometimes encased in cement blocks and lowered into clay beds. There is a concern that over time alkaline fluids near the clay surface will alter its effectiveness as a barrier to the encased nuclear waste. Studies by the nuclear industry to increase their understanding of the cement-to-formation interface are ongoing. At the High Activity Disposal Experimental Site (HADES), an underground laboratory at Mol, Belgium (Glasser, 2001; Read et al., 2001), cement plugs were precured and then placed in cored-out holes in Boom clay. Samples were maintained at temperatures between 149°F and 185°F [65°C and 85°C]. The samples were cored out of the Boom clay after test periods of 12 or 18 months. Sections of the interface were analyzed by electron microprobe and X-ray diffraction. Observations from the HADES study using ordinary Portland cement (OPC) plugs are summarized below (Read et al., 2001).

In the case of OPC samples exposed for only 12 months, different zones were apparent with mineralogical and textural changes reflecting transport of calcium, magnesium, aluminum, iron, silicon, and sulfur. These changes occurred across a region extending from 100 to 250 μm either side of the interface.

The clay was depleted in aluminum, silicon, and magnesium but enriched in calcium relative to the untreated clay. The outward diffusion of calcium was evident (~200 μm) from the precipitation of calcite in the clay. Also, the mineral hydrotalcite, Mg₆Al₂(CO₃)(OH)₁₆ · 4H₂O, formed in the initial 10- to 20-μm zone. In samples stored at 185°F [85°C], a fracture was observed at the interface of the altered and unaltered clay zones.

The cement layer was leached in appearance and had reduced calcium but increased silicon, sulfur, aluminum, and magnesium concentrations relative to the unaltered cement. After 1 year, increased porosity observed at the interface was attributed to portlandite dissolution.

Unfortunately, no details of the mechanical strength of the interface were given. However, the existence of an interfacial transition zone in construction concrete is well documented.

Concrete can contain OPC and granular materials such as calcined shale, limestone, or quartz (Mehta and Monteiro, 1986; 1987). In one study, Portland cement was set against quartz. After 28 days (at an unknown temperature), a continuous thin film of calcium hydroxide formed at the surface, and the cement was very porous. Below this film, other hydration products such as calcium silicate hydrate and ettringite appeared. Compared to the bulk concrete, the large crystal size in the transition zone (30 μm) was caused by the high water/cement ratio, which also accounts for the high porosity. Another source of weakness in this particular sample was the presence of Hadley grains (Barnes, 1975), which are hollow cement particles from which the solids have been dissolved. These form because of high local water-to-cement ratios.

The cement/limestone interface was found to be the same as that of the quartz experiment after a 28-day curing period (Mehta and Monteiro, 1988). At later stages (56 days or more), evidence of strong chemical bonding between the aggregate and the bulk cement paste was inferred from the fact that some of the cement paste adhered to the limestone surface. Microscopic evidence suggested the carbonate surface is etched by the cement.
and extra precipitated products are present in addition to the calcium hydroxide crystals on the cement side.

In the construction industry, concrete can contain expanded shale (Yun and Qingli, 1992; Schneider and Chen, 1992). This shale bears little relation to the hydrated shale found in wellbores. Expanded shale is prepared by grinding clay, mixing it with additives and heat-treating it at 2,190°F [1,200°C]. The resulting product contains elliptical particles that adsorb water and can form chemical bonds with the hydrated lime in the concrete. The pore throats in the expanded shale become filled with hydrated cement, leading to increased strength.

One approach to increasing the interfacial bond strength is to reduce the porosity of the interfacial transition zone. Alteration of the transition zone by adding silica or organics to the cement has been investigated (Caliskan, 2003; Kim and Robertson, 1998). Caliskan studied silica addition and reported a correlation between the reduction in the thickness of the interfacial transition zone and an increase in SiO2 content and bond strength. Kim et al. (2000) added polyvinyl alcohol to the cement formulation placed at the limestone interface. They attributed the bond-strength increase to the porosity reduction in the interfacial transition zone and the inhibition of calcium hydroxide production.

Reactions between minerals and alkaline fluids will affect the barrier properties (including permeability) and the chemical properties (e.g., sorption potential and cation exchange capacity) of the host rock (Hodgkinson and Hughes, 1999). These rocks are likely to be altered by the dissolution and/or precipitation reactions. Ion exchange may occur in clays and may play a significant part in the alteration of smectite materials (Jefferyes et al., 1988; Johnston and Miller, 1984; Koomareni and White, 1981).

6-4.8 Cement-to-formation bonding conclusion
This section has summarized what is known in the petroleum and civil-engineering industries about the cement/formation interface. The quality of the bond at this interface is affected by many variables, including the formation composition, drilling-fluid composition, cement-slurry composition, temperature, and pressure. Clearly, more research will be required to achieve a satisfactory understanding that will lead to more reliable zonal isolation.

6-5 Cementing across evaporite zones
The presence of salt domes and massive evaporite sequences has long been problematic for drilling, completion, and long-term production. The high water solubility and plasticity of such zones increase the difficulty of obtaining a successful primary cementation. The cement slurry can dissolve large quantities of formation material, resulting in a modification of performance (Ludwig, 1951). Plastic salt zones can encroach upon the casing before the cement sets. Nonuniform formation movement exerts point loading on the casing string, sometimes resulting in casing failure and collapse (Cheatham and McEver, 1964). Salt cements are used routinely to reduce the severity of these problems; however, some controversy exists regarding their efficacy (Chapter 7).

The first recorded use of salt in well cements was during the 1940s, when wells were completed across salt domes in the U.S. Gulf Coast. Later, this became standard practice in the Williston basin (North Dakota and Montana in the United States) and certain areas in the North Sea. The concentration of NaCl usually varied from 18% to 37% by weight of water (BWOW). While such practices prevented the dissolution of the formation, the high salt concentrations impeded the performance of other cement additives, especially dispersants and fluid-loss additives, which were originally developed for freshwater systems. In addition, the high salt concentrations tended to overretard the cement system; thus, formation encroachment and casing damage could occur before the cement set. Two approaches have been followed to solve these difficulties: eliminating salt from the cement system and developing additives that are compatible with salt cements.

Salt-free cement (Goodwin and Phipps, 1982), or cements containing very low salt concentrations (3% BWOW) have been successfully applied in the Williston basin (Bryant, 1984) and the Middle East (Ismaiel and Khalaf, 1993). No casing collapse was reported with such systems, compared to a 20% failure rate with salt-saturated cements. To prevent excessive dissolution of the formation, the cement-slurry displacement rates were low.

Ford et al. (1982) proposed an intermediate approach. Cement systems containing 18% NaCl BWOW, in combination with holding the casing in tension during the cement job, improved the success rate of primary cement jobs in the Williston basin.

The above approaches may improve initial results; however, considering the previously discussed long-term effects of ionic disequilibrium, cement failure may ultimately occur. The rate of ionic diffusion is determined by the difference in salt concentration between the cement and formation as well as the permeability of the cement.

In addition, Rae and Brown (1988) revealed that contamination of a freshwater cement system by as little as 10% salt could reduce the thickening time by 30%, increase the slurry viscosity by 100%, and increase the...
fluid-loss rate by nearly 500%. Yearwood et al. (1988) confirmed these findings.

Today, it is possible to design cement systems with appropriate performance throughout the salt-concentration range. Cement systems containing from 5 to 37% NaCl (BWOW), with excellent placement characteristics, appropriate thickening times, and acceptable compressive-strength development are now commonplace. Such systems are described in Chapter 7.

Selecting the appropriate salt concentration in a cement slurry is largely a function of the local formation characteristics, operational limitations, and success ratios. There is no industry consensus regarding slurry design for salt-zone cementing. At present, anecdotal evidence shows that the majority of salt zones are cemented with systems containing between 8 to 18% NaCl (BWOW). In addition, scrupulous attention is given to proper hole conditioning and good cementing practices.

Blast-furnace slag, combined with Portland cement or drilling fluids, has also been used recently to cement salt zones. This application is also discussed in Chapter 7.

6-6 Gas hydrates

Gas hydrates are a special combination of two common substances, water and natural gas. If these meet under conditions in which the pressure is high and the temperature low, they join to form a solid, ice-like substance. Vast volumes of shallow sediments below the deep ocean mud line and in arctic regions are conducive to hydrate formation. The basic hydrate unit is a hollow crystal of water molecules with a single gas molecule trapped inside. The crystals fit together in a tight latticework. At typical deepwater seabed temperatures around 39°F [3.8°C] methane hydrates can form at any pressure over about 550 psi [3.8 MPa].

The petroleum industry began to take an interest in gas hydrates in the 1930s, when gas-hydrate formation was found to be a cause of pipeline blockages. Since then, most industry efforts related to gas hydrates have been directed toward preventing them or hindering their accumulation into blocking masses. However, in recent years, interest in exploiting gas hydrates for their hydrocarbons is becoming more intense.

For operators drilling in deep water, encountering naturally occurring gas hydrates during drilling can pose a well-control problem if large amounts enter the borehole and dissociate. Furthermore, circulation of warm fluid within the wellbore can increase the temperature in the surrounding hydrate-rich sediments, leading to hydrate melting and destabilization of the sediments supporting the well. Conditions vary by location, but typically water depths greater than 1,500 ft are conducive to hydrate formation, and the hydrate stability zone can extend as deep as 2,000 ft below the mudline. However, in most deepwater areas, including the Gulf of Mexico, most of the sediments encountered contain less than 10% of pore volume hydrates and historically do not represent a serious drilling hazard. Before drilling, a geo-hazard survey is normally performed to locate hydrate-rich areas, such as seeps and large active faults. This allows the operator to avoid hazardous areas (personal communication, J.B. Bloys, 2004).

Very little has been published about the interactions between cement systems and gas hydrates. Special cement systems with low heats of hydration, described in Chapter 7, have been recommended to help prevent hydrate dissociation in arctic areas where hydrate concentrations near the base of permafrost can be as high as 80% (Collett et al., 2000).

6-7 Acronym list

API American Petroleum Institute
BWOW By weight of water
ECP External casing packer
EPS Engineered particle-size
HADES High Activity Disposal Experimental Site
IPT Ideal packing theory
ISO International Organization for Standardization
LCM Lost circulation material
M-DOB Mud-diesel-oil-bentonite
M-DOB2C Mud-diesel-oil-bentonite-cement
MMH Mixed metal hydroxides
MMO Mixed metal oxide
MMOOH Mixed metal oxide and hydroxide
OBM Oil-base mud
OPC Ordinary Portland cement
PCP polymer-based crosslinked pills
PHPA Partially hydrolyzed polyacrylamide
PSD Particle-size distribution
PTFE Polytetrafluoroethylene
PV Plastic viscosity
SWBS Small wellbore simulator
WBM Water-base mud
WOC Waiting on cement
YP Yield point
7-1 Introduction
As well cementing technology has advanced, special cement systems have been developed to address specific problems. This chapter presents cement technologies specific to problems such as slurry fallback, lost circulation, microannuli, cementing across salt formations, and corrosive well environments. Some of these solutions were introduced more than 50 years ago, yet they are still commonly used today.

Other systems have been developed with special performance characteristics such as flexible cements and drilling fluids that convert to a hardened cementitious product. This chapter also contains a thorough discussion of foamed cements and cement systems with multimodal particle-size distributions.

Special technologies also exist for problems such as annular fluid migration and high well temperatures. These are presented in Chapters 9 and 10.

7-2 Thixotropic cements
A thixotropic system is fluid under shear, but develops a gel structure and becomes self-supporting when at rest (Shaw, 1970). In practical terms, thixotropic cement slurries are thin and fluid during mixing and displacement but rapidly form a rigid, self-supporting gel structure when pumping ceases. Upon reagitation, the gel structure breaks and the slurry regains fluidity. Then, upon cessation of shear, the gel structure reappears and the slurry returns to a self-supporting state. This type of rheological behavior is continuously reversible with truly thixotropic cements.

As a rule, thixotropic slurries behave as Bingham plastic fluids under stress (Chapter 4); consequently, their behavior is defined by a yield value ($\tau_y$) and a plastic viscosity ($\mu_p$) (Clement, 1979). $\tau_y$ is a theoretical value concerning the behavior of a fluid under conditions of shear. With thixotropic slurries, $\tau_y$ would be the shear stress necessary to initiate movement, i.e., measured at zero shear rate.

For a nonthixotropic fluid, the yield value remains the same whether the shear rate is increasing or decreasing. There is no change in the physical structure of the fluid during the static period, and the pressure required to move the fluid does not change with time. In the case of a thixotropic fluid, the yield point is exhibited only upon the withdrawal of shear stress. If there is a lapse of time after the withdrawal of shear, a force greater than the yield point will be required to move the fluid, as indicated in Figs. 7-1, 7-2, and 7-3. The difference between the “gel strength” and the yield point gives a measure of the “degree of thixotropy” of the fluid.

Thixotropic cement systems have several important applications. They can be used in wells in which excessive fallback of the cement column is a common occurrence (Wieland et al., 1969). Such wells have weak zones that fracture under low hydrostatic pressure, allowing the cement slurry to invade the formation. Self-supporting cements reduce the hydrostatic pressure on the formation as gel strength increases and prevent fallback.

Another important application is the prevention of lost circulation during placement (Chapter 6). When a thixotropic slurry enters the thief zone, the velocity of the leading edge decreases and a gel structure begins to develop. Eventually, the zone becomes plugged because of the increased flow resistance. Once the cement sets, the zone is effectively consolidated.
Other uses for thixotropic cement systems include:

- to repair split or corroded casing
- as lead slurries for remedial cementing when it is difficult to obtain a squeeze pressure (Spangle and Calvert, 1972; Welch et al., 1990) (Chapter 14)
- as a grout, to quickly immobilize the slurry
- to prevent gas migration in certain situations (Chapter 9).

Thixotropic cement slurries have another notable characteristic. After each static-dynamic cycle, the gel strength and yield point tend to increase. During cementing operations this could pose a problem because, after repeated stops, excessive pump pressure may be required to resume movement. To minimize the risk of job failure, most operators prefer to avoid pump shutdowns when placing thixotropic cement slurries. The use of thixotropic cements has decreased in recent years owing to the development of low-density cement systems that provide excellent zonal isolation (Sections 7-9 and 7-10).

Several thixotropic cement systems currently exist. The chemistry and special operational considerations of each are described below.

### 7-2.1 Clay-base systems

Portland cement systems containing water-swellable clays such as bentonite develop high gel strength and exhibit some degree of thixotropic behavior (Messenger, 1980). Such systems have also been shown to control gas migration in certain circumstances (Chapter 9). The bentonite concentration and the slurry density can be varied from 0.05% to 2.0% by weight of cement (BWOC) and 11.5 and 21.0 lbm/gal [1,381 to 2,521 kg/m³], respectively.

### 7-2.2 Calcium sulfate-based systems

The most widely used material to prepare thixotropic cement slurries is calcium sulfate hemihydrate (CaSO₄ • ½H₂O or, in cement notation, CSH½) (also called plaster of paris). When added to Portland cement, CSH½ first hydrates to form gypsum (CaSO₄ • 2H₂O or CSH₂) and then reacts with tricalcium aluminate (C₃A) to form the calcium sulfoaluminate hydrate mineral ettringite (Chapter 2). The chemical equation for the reaction is shown below (Kalousek, 1973).

\[
3\text{CaSO}_4 \cdot 2\text{H}_2\text{O} + 3\text{CaO} \cdot \text{Al}_2\text{O}_3 \xrightarrow{\text{H}_2\text{O}} 3\text{CaO} \cdot \text{Al}_2\text{O}_3 \cdot 3\text{CaSO}_4 \cdot 32\text{H}_2\text{O} \tag{7-1}
\]

ettringite

Ettringite occurs as needle-shaped crystals deposited on the cement-grain surfaces. The ettringite crystals promote greater physical association between the cement particles, resulting in the formation of a loose network or gel. Upon agitation, the network is easily disrupted, and the slurry returns to a fluid state.

Calcium sulfate hemihydrate can be used with most Portland cements to prepare thixotropic cements. Depending upon the cement, the optimal CSH½ concentration varies between 8% and 12% BWOC. Cements with a C₃A content of less than 5% should be used with caution, because insufficient ettringite may crystallize to impart thixotropy. The water requirement for...
slurries containing calcium sulfate hemihydrate is higher than that for conventional systems; consequently, the slurry densities are lower. Representative data for such systems are presented in Table 7-1.

<table>
<thead>
<tr>
<th>System</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density (lbm/gal)</td>
<td>15.6</td>
<td>14.9</td>
<td>14.6</td>
<td>14.6</td>
<td>14.2</td>
</tr>
<tr>
<td>Water (%BWOC)</td>
<td>46</td>
<td>60</td>
<td>64</td>
<td>64</td>
<td>70</td>
</tr>
<tr>
<td>Water (gal/sk)</td>
<td>5.20</td>
<td>6.78</td>
<td>7.20</td>
<td>7.20</td>
<td>7.90</td>
</tr>
<tr>
<td>Calcium sulfate hemihydrate (%BWOC)</td>
<td>0</td>
<td>12</td>
<td>10</td>
<td>12</td>
<td>10</td>
</tr>
<tr>
<td>CaCl2 (%BWOC)</td>
<td>0</td>
<td>3</td>
<td>2</td>
<td>3</td>
<td>0</td>
</tr>
<tr>
<td>Yield (ft³/sk)</td>
<td>1.18</td>
<td>1.48</td>
<td>1.50</td>
<td>1.54</td>
<td>1.60</td>
</tr>
</tbody>
</table>

Well conditions (°F)

- BHCT: 113, 60, 80, 80, 125
- BHST: 170, 70, 95, 95, 200

Thickening time at BHCT (hr:min)

- 4:00+: 3:10, 2:08, 1:50, 3:15

Compressive strength (psi) at BHST

<table>
<thead>
<tr>
<th>Time</th>
<th>7 hr</th>
<th>18 hr</th>
<th>24 hr</th>
<th>96 hr</th>
</tr>
</thead>
<tbody>
<tr>
<td>350</td>
<td>1,750</td>
<td>2,900</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>100</td>
<td>–</td>
<td>1,165</td>
<td>1,295</td>
<td>1,150</td>
</tr>
<tr>
<td>485</td>
<td>–</td>
<td>1,250</td>
<td>1,350</td>
<td>–</td>
</tr>
<tr>
<td>500</td>
<td>–</td>
<td>1,750</td>
<td>2,200</td>
<td>–</td>
</tr>
<tr>
<td>950</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
</tbody>
</table>

† not available

Thixotropic cements containing calcium sulfate hemihydrate are incompatible with many fluid-loss additives. Jones and Carpenter (1991) overcame this problem by adding 1.5% BWOC polyvinyl alcohol to the cement slurry.

Calcium sulfate hemihydrate systems have additional attributes besides thixotropy. Such systems are highly sulfate resistant, because the C3A is effectively neutralized (Chapter 2). Also, after setting, ettringite continues to form; as a result, a significant amount of bulk expansion occurs within the cement matrix. This phenomenon, and the benefits derived from it, are addressed in detail later in this chapter.

7-2.3 Aluminum sulfate/iron (II) sulfate system

A blend of Al₂(SO₄)₃ and FeSO₄ also relies upon the formation of ettringite to impart thixotropy to cement slurries (Nelson, 1983). This blend was developed for use with Portland cements that contain less than 5% C₃A. It can be supplied in liquid form, which is convenient for offshore operations.

These soluble sulfates react with calcium hydroxide in the cement slurry to form gypsum in situ, and ettringite formation then proceeds. The global reaction is shown below.

\[
\text{Al}_2(\text{SO}_4)_3 + 6\text{Ca(OH)}_2 + \text{H}_2\text{O} \rightarrow 3\text{CaO} \cdot \text{Al}_2\text{O}_3 \cdot 3\text{CaSO}_4 \cdot 32\text{H}_2\text{O} \quad (7-2)
\]

This reaction proceeds much faster than that involving calcium sulfate hemihydrate. Aluminum sulfate is a powerful cement accelerator, and a strong, irreversible gel structure would develop if it were added alone. Iron (II) sulfate, a weak cement retarder, is included in the system to inhibit the aluminum sulfate and preserve thixotropy throughout the pumping time. Because of the fast kinetics of this system, very little ettringite is formed after the cement sets. Thus, significant cement expansion does not occur at curing temperatures above 100°F [38°C].

7-2.4 Crosslinked cellulose polymer systems

Thixotropic cements can be prepared by the addition of water-soluble crosslinkable polymers and a crosslinking agent (Childs et al., 1985). Hydroxyethylcellulose, carboxymethylhydroxyethyl cellulose, polyvinyl alcohol, and various sulfonate polymers can be crosslinked with certain titanium or zirconium chelates. The optimal polymer-crosslinker combination, and the relative concentrations of each, vary with the well temperature.

7-3 Expansive cement systems

Good bonding between the set cement and casing and between the set cement and the formation is essential for effective zonal isolation. Poor bonding limits production and reduces the effectiveness of stimulation treatments (Chapter 1). Communication between zones can be caused by inadequate mud removal, poor cement/formation bonding, expansion and contraction of the casing resulting from internal pressure or thermal stress, and cement contamination by drilling or formation fluids. Under such circumstances, a small gap or “microannulus” is frequently present at the cement/casing or the cement/formation interface (Moran et al., 1991; Baumgarte et al., 1999).

Cement systems that expand slightly after setting are a proven means of sealing microannuli and improving primary cementing results. The improved bonding is the result of mechanical resistance or tightening of the cement against the pipe and formation. However, expansive cement systems are not a substitute for the good cementing practices that lead to maximum mud
removal (Chapter 5). Expansive cements cannot cure the problems associated with mud that is left on the casing or formation surfaces.

From Chapter 2, the reader may recall that Portland cement manufacturers limit the amount of certain alkaline impurities to avoid expansion of the set cement, a condition called “unsoundness.” In an unrestrained environment such as a road or building, expansion of the set cement can result in cracking and failure. In a wellbore environment, however, the cement is restrained by the casing and, when competent, the formation; consequently, once the cement has expanded to eliminate void spaces, further expansion reduces internal cement porosity. It is important to note that expanding cements must be more flexible than the formation; otherwise, the cement will not expand toward the casing, and a microannulus may form.

7-3.1 Ettringite systems

Most expansive well cement systems rely upon the formation of ettringite, discussed in the preceding section, after the cement has set. Ettringite crystals have a greater bulk volume than the components from which they form; consequently, expansion occurs because of the internal pressure exerted upon crystallization. Currently, there are four commercial expanding cement systems that rely on ettringite formation.

Type K cement is a blend of Portland cement, calcium sulfate, lime, and anhydrous calcium sulfoaluminate (Klein and Troxell, 1958). This cement is composed of two separately burned clinkers that are ground together. Type K cement systems typically expand by 0.05% to 0.20%.

Type M cement is either a blend of Portland cement, refractory calcium aluminate cement (Chapter 10), and calcium sulfate, or an interground product made with Portland cement clinker, calcium aluminate cement clinker, and calcium sulfate (Root and Calvert, 1971).

Type S cement is a commercially prepared blend of high-C\textsubscript{3}A Portland cement with 10.5% to 15% gypsum.

The fourth and most common method of preparing an ettringite-based expansive cement is to add calcium sulfate hemihydrate to a Portland cement containing at least 5% C\textsubscript{3}A. This formulation is similar to Type S; however, because the blend is prepared as needed before a cement job, shelf life is not a concern. As discussed in the previous section, such systems are also thixotropic. If this is not desired, the thixotropy can be defeated by adding a cement dispersant. The expansion performance of Portland cement–calcium sulfate hemihydrate systems is illustrated in Fig. 7-4.

A major limitation of ettringite-based systems is their inability to provide significant expansion at curing temperatures above about 170°F [76°C] (Bour et al., 1988).

Ettringite is not stable at higher temperatures and converts to a more dense calcium sulfoaluminate hydrate and gypsum according to the following chemical equation (Bensted, 2001).

\[
\begin{align*}
2\text{Al(OH)}_3 + 3\text{SO}_4^{2-} + 6\text{Ca}^{2+} + 12\text{OH}^- & \rightarrow 3\text{CaO} \cdot \text{Al}_2\text{O}_3 \cdot \text{CaSO}_4 \cdot 12\text{H}_2\text{O} + \nonumber \\
2\text{CaSO}_4 \cdot 2\text{H}_2\text{O} + 16\text{H}_2\text{O} & \nonumber
\end{align*}
\]

(7-3)

7-3.2 Salt cements

Cement slurries containing high concentrations of NaCl, Na\textsubscript{2}SO\textsubscript{4}, or both were among the earliest expansive well cements (Carter et al., 1965). After setting, cement expansion occurs because of internal pressure exerted by the crystallization of the salts within pores and by chlorosilicate and chlorosulfoaluminate reactions (Smith, 1976). Typical expansion performance of such systems at ambient conditions is shown in Fig. 7-5. These systems are equally effective at temperatures up to 400°F [204°C].

Other applications of salt cements are presented later in this chapter (Section 7-5).
7-3.3 Aluminum powder
Zinc, magnesium, iron, and aluminum powders can be used to prepare expansive cements (Carter et al., 1965). Finely powdered aluminum reacts with the alkalis in the cement slurry to produce tiny bubbles of hydrogen gas. This system is effective in shallow well applications, because the expansive pressure of the bubbles is greater than the formation pressure. The performance of such systems is illustrated in Table 7-2.

Table 7-2. Effect of Pressure on Expansion of Cement Systems Containing Powdered Aluminum†‡

<table>
<thead>
<tr>
<th>Aluminum (%)</th>
<th>Volume Expansion (%) (at 80°F)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Curing Pressure</td>
</tr>
<tr>
<td></td>
<td>0 psi</td>
</tr>
<tr>
<td>0.05</td>
<td>11.84</td>
</tr>
<tr>
<td>0.10</td>
<td>17.90</td>
</tr>
<tr>
<td>0.25</td>
<td>24.00</td>
</tr>
<tr>
<td>0.50</td>
<td>56.51</td>
</tr>
<tr>
<td>1.00</td>
<td>57.19</td>
</tr>
</tbody>
</table>

† After Carter et al. (1965). Reprinted with permission of SPE.
‡ At 80°F.

The rate of hydrogen liberation is strongly affected by the fineness and concentration of aluminum, temperature, and pressure. Thus, careful slurry design is necessary to obtain optimal results. More recently, the pressurization effect of aluminum powder systems has been applied to prevent gas migration (Chapter 9).

7-3.4 Calcined magnesium oxide
The hydration of magnesium oxide to magnesium hydroxide provides an expansive force within the cement matrix. The hydrated material occupies more space than that of the original ingredients.

\[ \text{MgO (periclase)} + \text{H}_2\text{O} \rightarrow \text{Mg(OH)}_2 \text{(brucite)} \] (7-4)

The MgO must be calcined at very high temperatures, between 2,012° and 2,372°F [1,100° and 1,300°C]; otherwise, the hydration occurs before the cement sets, and no significant cement expansion is observed (Spangle, 1988; Ghofrani and Plack, 1993; Rubiandini, 2000).

Cement systems containing MgO provide excellent expansive performance at curing temperatures as high as 550°F [288°C]. However, at temperatures below about 140°F [60°C], the hydration reaction proceeds too slowly to be of practical benefit. The MgO concentration required for adequate expansion varies between 0.25% and 1.00% BWOC, depending on temperature. Figure 7-6 shows the expansion performance of a Class G cement system containing 1.0% MgO BWOC and illustrates that the amount of expansion increases with increasing temperature.

![Fig. 7-6. Expansion of cement containing 1% BWOC calcined MgO.](image)

7-4 Freeze-protected cements
Permafrost zones in Alaska, northern Canada, and Siberia present unique cementing difficulties. Permafrost is defined as any permanently frozen subsurface formation. The depths of such formations vary from a few meters to 2,000 ft [600 m]. Below the permafrost, the geothermal gradients are normal. Permafrost sections vary from unconsolidated sands and gravels containing ice lenses to ice-free, consolidated rock.

During drilling and completion, a permafrost formation must not be allowed to thaw. Melting can cause the thawed earth to subside, particularly in the upper 200 ft [60 m] of the well (Thorvaldson, 1962). The cement system should have a low heat of hydration and be able to develop sufficient compressive strength (without freezing) at temperatures as low as 20°F [-3°C]. Casing strings must be cemented to surface, or a nonfreezing fluid placed in the annulus, to prevent casing damage owing to the expansion of water upon freezing.

Conventional Portland cement systems are not satisfactory in permafrost conditions, because they freeze before developing sufficient compressive strength. It is possible to add salt, alcohol, or other freeze-depressing materials to the mix water; however, these additives have adverse effects upon the quality of the set cement (Morris, 1970). Several types of cement systems perform...
successfully in this severe environment: (1) calcium aluminate cement, (2) gypsum-Portland cement blends (Benge et al., 1982), and (3) ultrafine Portland cement (Harris, 1991).

As described in Chapter 10, calcium aluminate cement is a special-use material of limited production. It is used to cement in situ combustion thermal wells. Such cements also set and gain strength rapidly at low and near-freezing temperatures (Maier et al. 1971). Fly ash is often added as a diluent to reduce the cement’s heat of hydration and for economy. The typical performance of 50:50 fly ash-calcium aluminate cement systems is shown in Table 7-3.

Table 7-3. Performance of 50:50 Calcium Aluminate-Fly Ash Cement Systems

<table>
<thead>
<tr>
<th>Sodium Chloride (%)</th>
<th>Slurry Weight (lbm/gal)</th>
<th>Slurry Volume (ft³)</th>
<th>Curing Temperature (°F)</th>
<th>Curing Time (hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>14.8</td>
<td>0.95</td>
<td>20</td>
<td>8</td>
</tr>
<tr>
<td>5</td>
<td>14.9</td>
<td>0.97</td>
<td>20</td>
<td>8</td>
</tr>
<tr>
<td>10</td>
<td>15.0</td>
<td>0.96</td>
<td>20</td>
<td>8</td>
</tr>
<tr>
<td>0</td>
<td>14.8</td>
<td>0.95</td>
<td>20</td>
<td>NS††</td>
</tr>
<tr>
<td>5</td>
<td>14.9</td>
<td>0.97</td>
<td>20</td>
<td>NS††</td>
</tr>
<tr>
<td>10</td>
<td>15.0</td>
<td>0.96</td>
<td>20</td>
<td>NS††</td>
</tr>
<tr>
<td>0</td>
<td>14.8</td>
<td>0.95</td>
<td>40</td>
<td>8</td>
</tr>
<tr>
<td>5</td>
<td>14.9</td>
<td>0.97</td>
<td>40</td>
<td>8</td>
</tr>
<tr>
<td>10</td>
<td>15.0</td>
<td>0.96</td>
<td>40</td>
<td>8</td>
</tr>
<tr>
<td>0</td>
<td>14.8</td>
<td>0.95</td>
<td>60</td>
<td>8</td>
</tr>
<tr>
<td>5</td>
<td>14.9</td>
<td>0.97</td>
<td>60</td>
<td>8</td>
</tr>
<tr>
<td>10</td>
<td>15.0</td>
<td>0.96</td>
<td>60</td>
<td>8</td>
</tr>
</tbody>
</table>

Table 7-4. Typical Compressive-Strength Data for a 50:50 Gypsum-Portland Cement Blend

<table>
<thead>
<tr>
<th>Temperature (°F)</th>
<th>Compressive Strength (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>At 16 hr</td>
</tr>
<tr>
<td>20</td>
<td>300</td>
</tr>
<tr>
<td>40</td>
<td>450</td>
</tr>
<tr>
<td>60</td>
<td>700</td>
</tr>
<tr>
<td>80</td>
<td>750</td>
</tr>
</tbody>
</table>

Table 7-5. Compressive Strength of a 50:50 Gypsum-Portland Cement Blend After Freeze-Thaw Cycling

<table>
<thead>
<tr>
<th>Day</th>
<th>°F</th>
<th>psi</th>
<th>Day</th>
<th>°F</th>
<th>psi</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>40</td>
<td>860</td>
<td>14</td>
<td>100</td>
<td>2,750</td>
</tr>
<tr>
<td>2</td>
<td>40</td>
<td>970</td>
<td>15</td>
<td>50</td>
<td>3,100</td>
</tr>
<tr>
<td>3</td>
<td>30</td>
<td>1,250</td>
<td>16</td>
<td>15</td>
<td>3,480</td>
</tr>
<tr>
<td>4</td>
<td>15</td>
<td>1,450</td>
<td>17</td>
<td>50</td>
<td>2,850</td>
</tr>
<tr>
<td>5</td>
<td>50</td>
<td>1,790</td>
<td>18</td>
<td>100</td>
<td>2,820</td>
</tr>
<tr>
<td>6</td>
<td>100</td>
<td>1,990</td>
<td>19</td>
<td>160</td>
<td>2,740</td>
</tr>
<tr>
<td>7</td>
<td>160</td>
<td>2,100</td>
<td>20</td>
<td>160</td>
<td>2,680</td>
</tr>
<tr>
<td>8</td>
<td>160</td>
<td>2,270</td>
<td>21</td>
<td>160</td>
<td>2,690</td>
</tr>
<tr>
<td>9</td>
<td>160</td>
<td>2,360</td>
<td>22</td>
<td>160</td>
<td>2,670</td>
</tr>
<tr>
<td>10</td>
<td>160</td>
<td>1,980</td>
<td>23</td>
<td>160</td>
<td>3,380</td>
</tr>
<tr>
<td>11</td>
<td>160</td>
<td>2,520</td>
<td>24</td>
<td>160</td>
<td>2,750</td>
</tr>
<tr>
<td>12</td>
<td>160</td>
<td>2,420</td>
<td>25</td>
<td>160</td>
<td>2,710</td>
</tr>
<tr>
<td>13</td>
<td>160</td>
<td>2,460</td>
<td>26</td>
<td>100</td>
<td>3,000</td>
</tr>
</tbody>
</table>

Gypsum-Portland cement blends, with sodium chloride as a mix-water freezing depressant, are used extensively for permafrost cementing. The gypsum sets and gains strength rapidly at freezing temperatures and prevents the slower-setting Portland cement from freezing. Such cement systems also have a lower heat of hydration than that of calcium aluminate cement; therefore, they are particularly applicable to unconsolidated permafrost formations. The typical performance of a 50:50 blend of gypsum and Portland cement, with 12% NaCl by weight of water (BWOW), is shown in Table 7-4. The effect of freeze/thaw cycling upon compressive strength is illustrated in Table 7-5. No degradation of strength is observed.

Ultrafine Portland cements generally have Blaine finenesses greater than 10,000 cm²/g, about three times greater than conventional Portland cement (Section 7-12). It is well known that early compressive strength is directly related to the surface area of the cement grains. Greater surface area causes an accelerated reaction rate because of the increased availability of reaction sites (Frigione and Marra, 1976). Figure 7-7 shows the compressive strength development of an ultrafine cement system mixed with fresh water and seawater, compared with a gypsum-Portland cement blend at 40°F.
Cement systems that contain significant quantities of NaCl or KCl are commonly called “salt cements.” Salt has been used extensively in well cements for three principal reasons.

- In certain areas (e.g., offshore), salt is present in the available mix water.
- Salt is a common and inexpensive chemical that, when used as an additive, can modify the behavior of the cement system.
- During cementing across massive salt formations or water-sensitive zones, cement slurries containing large amounts of salt prevent dissolution of the salt formation and prevent clay swelling.

### 7-5.1 Salty water as mixing fluid

In the absence of fresh water, brackish water or seawater is frequently used for mixing cement slurries. Such waters are advantageous because of their availability and economy.

Brackish waters from ponds and other surface water bodies vary significantly and should be thoroughly tested in the laboratory before use on location. The most important ions to monitor are Cl\(^{-}\), SO\(_4\)\(^{2-}\), Ca\(^{2+}\), Mg\(^{2+}\), and various organic compounds resulting from the decomposition of plant material. Such impurities have significant effects upon the performance of Portland cement systems, including gelation, overretardation, or both (Kieffer and Rae, 1987). All laboratory cement-slurry design experiments should be performed with a sample of the location water.

Seawater is the basic mixing fluid for offshore cementing operations. Lyman and Fleming (1940) and McIlhenny and Zeitoun (1969) characterized seawaters from various locations and, as shown in Table 7-6, found them to be reasonably uniform. Smith and Calvert (1974) confirmed seawater to be suitable for preparing well cements and stated that the performance is “predictable to a safe degree.”

![Fig. 7-7. Compressive strength development of ultrafine Portland cement system compared to a gypsum-Portland cement blend (from Harris, 1991). Slurry density is 12.2 lbm/gal and temperature is 40°F [4°C]. Reprinted with permission of SPE.](image-url)
Comparative laboratory testing has identified the following effects of seawater upon the performance of Portland cement systems:

- reduced thickening time (Table 7-7)
- higher fluid-loss rate
- higher early compressive strength at low temperatures (Table 7-7)
- slight dispersing effect
- higher shear-bond strength
- increased tendency for slurry foaming during mixing.

As discussed in Chapter 3, the presence of salt depresses the ability of bentonite to extend a cement slurry. Thus, either prehydration of the bentonite or the use of attapulgite is necessary (Smith and Calvert, 1974).

### Table 7-7. Thickening-Time and Compressive-Strength Behavior of Cement Mixed with Fresh Water and Seawater

<table>
<thead>
<tr>
<th></th>
<th>Thickening Time (hr:min) at 6,000 ft</th>
<th>Compressive Strength (psi) at 100°F after 24 hr</th>
</tr>
</thead>
<tbody>
<tr>
<td>Class A mixed with fresh water</td>
<td>2:32</td>
<td>1,780</td>
</tr>
<tr>
<td>Class A mixed with seawater</td>
<td>2:05</td>
<td>2,150</td>
</tr>
</tbody>
</table>

### 7-5.2 Salt as a cement additive

Salt is an extremely versatile cement additive that has been used in well cements for more than 50 years. Depending upon its concentration in the slurry, salt can behave as an accelerator or a retarder (Chapter 3). Salt is also used to disperse cement slurries (Chapter 3), induce cement expansion (Section 7-3.2), and prepare freeze-protected cements (Section 7-4).

### 7-5.3 Cementing across shale and bentonitic clay formations

Approximately 87% of petroleum reservoirs contain clay minerals and silica fines (Hill, 1982). Drilling through and cementing across such formations changes the chemical environment surrounding the clays and may induce destabilization, clay swelling, or fines migration, resulting in formation damage. For this reason, freshwater cement slurries are not appropriate for primary cementing across certain shale or bentonitic clay formations. This problem was first identified when remedial cementing across such formations was found to be more successful if saline formation waters were used to mix the slurry (Slagle and Smith, 1963). In addition, laboratory studies have shown significant formation permeability reductions as a result of exposure to low-salinity fluids (Hewitt, 1963; Jones, 1964; Mungan, 1965).

Slagle and Smith (1963) tested the visual integrity of clay formations after immersion into cement slurries of varying salinity. Salt-saturated cements were most compatible with formations containing montmorillonite, illite, and chlorite. However, NaCl concentrations as low as 10% BWOW were often sufficient to prevent significant damage. Cunningham and Smith (1967) showed that saline cement filtrate restricts the swelling and migration of water-sensitive clays. Lewis et al. (1987) demonstrated improved bonding between salt cements and sensitive formations.

Beach (1982) demonstrated that the cement slurry salinity must be chosen with care. Beach observed that significant long-term deterioration occurred when the ionic concentration of the cement was not comparable to that of the formation. Disequilibrium causes ionic diffusion, which disrupts the Portland cement binder. In the same vein, Economides and Nolte (2000) recommended that cement slurries for sensitive formations should contain a minimum of salt (in equilibrium with the formation salinity), exhibit sufficient fluid-loss control to minimize cement filtrate invasion, and not be overdispersed (to minimize invasion by a large amount of free water).

### 7-5.4 Cementing across massive salt formations

The presence of salt domes and massive evaporite sequences has long been problematic for drilling, completion, and long-term production. The high water solubility and plasticity of such zones increase the difficulty of obtaining a successful primary cementation. The cement slurry can dissolve large quantities of formation material, resulting in a modification of performance (Ludwig, 1951). Plastic salt zones can also encroach upon the casing before the cement sets. Nonuniform formation movement exerts point loading on the casing string, sometimes resulting in casing failure and collapse (Cheatham and McEver, 1964). Salt cements are used routinely to reduce the severity of these problems; however, some controversy exists regarding their efficacy.

The first recorded use of salt in well cements was during the 1940s, when wells were completed across salt domes in the U.S. Gulf Coast. Later, this became standard practice in the Williston basin (North Dakota and Montana, USA) and certain areas in the North Sea. The concentration of NaCl usually varied from 18% to 37% BWOW. While such practices prevented the dissolution of the formation, the high salt concentrations impeded the performance of other cement additives, especially...
dispersants and fluid-loss additives that were originally developed for freshwater systems. In addition, the high salt concentrations tended to overretard the cement system; thus, formation encroachment and casing damage could occur before the cement set. Two approaches have been followed to solve these difficulties: eliminating salt from the cement system and developing additives that are compatible with salt cements.

Salt-free cement (Goodwin and Phipps, 1982), or cements containing very low salt concentrations (3% BWOW), have been successfully applied in the Williston basin (Bryant, 1984) and the Middle East (Ismail and Khalaf, 1993). No casing collapse was reported with such systems, compared to a 20% failure rate with salt-saturated cements. To prevent excessive dissolution of the formation, the cement-slurry displacement rates were low.

Ford et al. (1982) proposed an intermediate approach. Semisaturated cement systems (18% NaCl BWOW), in combination with holding the casing in tension, improved the success rate of primary cement jobs in the Williston basin.

The above approaches may improve initial results; however, considering the previously discussed long-term effects of ionic disequilibrium, cement failure may ultimately occur. The rate of ionic diffusion is determined by the difference in salt concentration between the cement and formation and the permeability of the cement (Kumar et al., 1987).

Experiments performed by P. Drecq (unpublished data, 1987) and van Kleef (1989) illustrated that low displacement rates would not necessarily prevent significant formation dissolution, because salt zones are not eroded by cement slurries during placement. Three salt blocks of equal dimensions were submerged for 60 min in cement slurries with various salt concentrations. The slurry temperature was 140°F [60°C], and slight agitation was provided. As shown in Fig. 7-8, significant salt erosion was observed, except when the cement was salt-saturated.

In addition, Rae and Brown (1988) revealed that contamination of a freshwater cement system by as little as 10% salt could reduce the thickening time by 30%, increase the slurry viscosity by 100%, and increase the fluid-loss rate by nearly 500%. Yearwood et al. (1988) confirmed these findings.

Research has been performed to develop salt-saturated cement systems (37.2% NaCl BWOW) without the disadvantages discussed earlier. In 1978, Messenger patented the use of certain hydroxycarboxylic acids as dispersants for salt cement slurries. Fluid-loss additives for salt cement systems have been developed by Chatterji and Brake (1982), Nelson (1986), Fry et al. (1987), and Bair et al. (2002).

As a result, it is possible to design cement systems with appropriate performance throughout the salt-concentration range. Cement systems containing from 5% to 37% NaCl (BWOW), with excellent placement characteristics, appropriate thickening times, and acceptable compressive-strength development were reported by Rae and Brown (1988), Yearwood et al. (1988), Whisonant, et al. (1988), and Brothers and deBlanc (1989). Typical performance data are presented in Tables 7-8 and 7-9. Successful field results using proprietary cement system compositions have been reported in various locations around the world.

### Table 7-8. Typical Compressive-Strength Performance of Proprietary Salt Cement Systems

<table>
<thead>
<tr>
<th>NaCl (%BWOW)</th>
<th>Cellulose/ Organic Acid (%BWOC)</th>
<th>BHST (°F)</th>
<th>Density (lbm/gal)</th>
<th>Compressive Strength at 3,000 psi</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>8 hr</td>
<td>24 hr</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>–1</td>
<td>200</td>
<td>15.8</td>
<td>1,850 2,600</td>
</tr>
<tr>
<td>15</td>
<td>–</td>
<td>200</td>
<td>15.8</td>
<td>1,700 2,300</td>
</tr>
<tr>
<td>30</td>
<td>–</td>
<td>200</td>
<td>16.6</td>
<td>2,020 2,650</td>
</tr>
<tr>
<td>30</td>
<td>0.8/0.1</td>
<td>200</td>
<td>16.6</td>
<td>0 2,500</td>
</tr>
<tr>
<td>30</td>
<td>–</td>
<td>200</td>
<td>16.6</td>
<td>1,350 2,100</td>
</tr>
<tr>
<td>30</td>
<td>0.8/0.1</td>
<td>200</td>
<td>16.2</td>
<td>0 2,040</td>
</tr>
<tr>
<td>30</td>
<td>–</td>
<td>230</td>
<td>16.2</td>
<td>1,450 2,150</td>
</tr>
</tbody>
</table>

*not applicable

---

[Fig. 7-8. Salt block appearance after 60 min of exposure to cements with various salinities (1: saturated; 2: 18% BWOW; 3: 7.5% BWOW) (after unpublished data by P. Drecq, 1987).]
Today, selecting the appropriate salt concentration in a cement slurry is largely a function of the local formation characteristics, operational limitations, and success ratios. There is no official industry consensus regarding slurry design for salt-zone cementing. At present, anecdotal evidence shows that most salt zones are cemented with systems containing between 8 to 18% NaCl (BWOW). In addition, scrupulous attention is given to proper hole conditioning and good cementing practices.

Blast-furnace slag (BFS) combined with Portland cement or drilling fluids has also been used recently to cement salt zones. This application is discussed in Section 7-8.2.2.

### 7-6 Latex-modified cement systems

Latex is a general term describing an emulsion polymer. The material is usually supplied as a milky suspension of very small spherical polymer particles (200 to 500 nm in diameter), often stabilized by surfactants to improve freeze/thaw resistance and prevent coagulation when added to Portland cement. Most latex dispersions contain about 50% solids. A wide variety of monomers, including vinyl acetate, vinyl chloride, acrylics, acrylonitrile, ethylene, styrene, and butadiene, is emulsion-polymerized to prepare commercial latexes.

The first use of latexes in Portland cements occurred in the 1920s, when natural rubber latex was added to mortars and concretes. Since then, latex-modified concretes have become commonplace because of the following improvements in performance (Ohama, 1987):

- improved pumptability
- decreased permeability
- increased tensile strength
- reduced shrinkage
- increased elasticity
- improved bonding between cement/steel and cement/formation interfaces.

As discussed in Chapter 2, absolute-volume shrinkage and internal volume reduction are a result of Portland cement hydration. Upon cement setting, stresses build within the matrix, resulting in the formation of microcracks (Fig. 7-9). The propagation of the cracks lowers the tensile capacity of the set cement and increases its permeability. In latex-modified systems (Fig. 7-10), the latex particles coalesce to form a plastic film that surrounds and coats the C-S-H phase. Because of its elasticity and high bonding strength, the latex bridges the microcracks and limits their propagation; as a result, the tensile strength of the set cement increases and the permeability decreases.

![Fig. 7-9. Photograph of microcracks in set Portland cement](from Kuhlmann, 1985). Reprinted with permission from Elsevier.)

---

<table>
<thead>
<tr>
<th>NaCl (%BWOW)</th>
<th>Cellulose/Organic Acid (%BWOC)</th>
<th>BHCT (°F)</th>
<th>Fluid Loss (mL/30 min)</th>
<th>Rheological Properties at BCHT</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Yield Value (lbf/100 ft²)</td>
</tr>
<tr>
<td>30</td>
<td>0.8/0.1</td>
<td>120</td>
<td>178</td>
<td>22</td>
</tr>
<tr>
<td>30</td>
<td>_†</td>
<td>120</td>
<td>64</td>
<td>0.2</td>
</tr>
<tr>
<td>30</td>
<td>0.8/0.1</td>
<td>160</td>
<td>285</td>
<td>31.3</td>
</tr>
<tr>
<td>30</td>
<td>_</td>
<td>160</td>
<td>52</td>
<td>0.1</td>
</tr>
</tbody>
</table>

† Not applicable
7-6.1 Behavior of latexes in well cement slurries

The use of latex in well cements occurred much later. In 1957, Rollins and Davidson reported improved performance when latex was added to the mix water. In addition to the attributes mentioned above, adding latex provided the following additional benefits:

- better bonding to oil-wet and water-wet surfaces
- less shattering when perforated
- increased resistance to contamination by well fluids
- lowered fluid-loss rate
- improved durability.

When latex is added as part of the liquid phase of a Portland cement system, the resulting slurry has a normal color and consistency; however, because of the solids content of the latex, such slurries contain 20% to 35% less water. After curing, the set product consists of hydrated cement particles connected by a film of latex particles (Kuhlmann, 1985). The film of latex particles imparts the physical and chemical properties described above (Parcevaux and Sault, 1984; Drecq and Parcevaux, 1988). While the slurry is still liquid, the latex particles impart excellent rheological properties because of a lubricating action. In addition, the latex particles provide excellent fluid-loss control by physically plugging small pores in the cement filtercake (Drecq and Parcevaux, 1988) (Chapter 3).

7-6.2 Early latex-modified well cement systems

In 1958, Eberhard and Park patented the use of vinylidene chloride latex in well cements. Improved performance was observed for systems containing up to 35% latex solids BWOC. Later, polyvinyl acetate latex was identified as a suitable material (Woodard and Merkle, 1964). The preferred concentration of latex solids varied from 2.5% to 25% BWOC. The polyvinyl acetate system has been used successfully for many years; however, it is limited to applications at temperatures less than 122°F [50°C] bottomhole static temperature (BHST).

7-6.3 Styrene butadiene latex systems

An improvement in latex cement technology occurred when Parcevaux et al. (1985) identified styrene butadiene latex as an effective additive for the prevention of annular gas migration (Chapter 9). Additional refinements were made by Sault et al. (1986).

Styrene butadiene latexes impart the same beneficial effects described above; however, they are effective at temperatures as high as 350°F [176°C]. Fig. 7-11 is a plot of API/ISO fluid-loss rate versus latex concentration for various well cement slurries. The results illustrate that normal-density neat slurries require less latex to achieve a given fluid-loss rate. More latex is required for slurries containing extenders or weighting agents, especially those with a lower solids content (extended with sodium silicate). Figure 7-12 illustrates the decreased volumetric shrinkage observed with a latex-modified Portland cement system cured at 158°F [70°C].

![Fluid-loss rates of latex-modified cement slurries (185°F [85°C]).](image)
7-7 Cements for corrosive environments

Set Portland cement is a remarkably durable and forgiving material, but it has its limits. In a wellbore environment, Portland cement is subject to chemical attack by certain formations, migrating fluids, and substances injected from the surface. As discussed in Chapter 10, saline geothermal brines containing CO₂ are particularly deleterious to the integrity of the set cement. Cement durability is also a key consideration in wells for chemical waste disposal and for enhanced oil recovery by CO₂ flooding.

7-7.1 Cements for chemical waste disposal wells

Zonal isolation is of paramount importance in chemical waste disposal wells. If not properly confined, injected waste fluids could contaminate freshwater aquifers and corrode the exterior of the casing. To ensure zonal isolation throughout the life of such wells, the cement and the tubular hardware in the well must be chemically resistant to the waste fluids (Runyan, 1974).

The chemically resistant casings used in waste disposal wells include modified polyester and epoxy fiber-cast, or metal alloys such as Carpenter 20,† Incoloy 825,‡ and Hastalloy G.§ The cement systems are chosen for compatibility with the injected waste material.

Modified Portland cements are generally appropriate for disposal wells involving weak organic acids, sewage waters, or solutions having a pH of 6 or above. The durability of the set cement is improved by adding pozzolans, increasing the density by addition of dispersants, employing controlled particle-size technology, or adding liquid latexes to the slurry. These methods substantially reduce the permeability of the set cement.

Portland cement systems are not compatible with strong inorganic acids such as sulfuric, hydrochloric, and nitric acid. In such environments, organic polymer cements, usually epoxy-based, must be used to provide sufficient chemical resistance (Cole, 1979). Such systems are also known as “synthetic cements.”

Epoxy cements are prepared by mixing an epoxy resin such as bisphenol-A (Fig. 7-13) with a hardening agent. Depending upon the desired end properties, the hardening agent can be an anhydride, aliphatic amine, or polyamide (Sherman et al., 1980). A solid filler such as silica flour is often used to build density, reduce cost, and act as a heat sink for the exothermic reaction that occurs during the curing period. Depending upon the circulating and static well temperatures, various catalysts and accelerators can also be added to control the placement and setting times.

Epoxy resin cement systems are characterized by their corrosion resistance and high compressive and shear-bond strength. They are compatible with strong acids and bases (up to 37% HCl, 60% H₂SO₄, and 50% NaOH) at temperatures up to 200°F [93°C] during extended exposure periods. Epoxies are also resistant to hydrocarbons and alcohols, but not to chlorinated organics or acetone. Typically, the compressive strengths range between 8,000 and 10,000 psi [56 to 70 MPa], and shear-bond strengths can be as much as 9 times higher than those of Portland cement (R.A. Bruckdorfer, unpublished data, 1985).

Until recently, to prevent premature setting and to enhance cement bonding, nonaqueous spacers such as gelled oil, diesel, or alcohol were required on all epoxy cement jobs. The use of such preflushes is costly and time consuming. In 2001, Eoff et al. introduced a water-compatible epoxy cement system. Instead of bisphenol-A, the epoxy sealant is the diglycidyl ether of cyclohexane dimethanol. The hardening agent is a mixture of diethyltoluenediamine and tris(dimethylaminomethylphenol). The performance of this system is unaffected by water contamination, up to 25% by volume.

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†Trademark of CRS Holdings, Inc.
‡Trademark of International Nickel Co.
§Trademark of Haynes International, Inc.
7-7.2 Cements for enhanced oil recovery by CO₂ flooding

Corrosion owing to CO₂ in production operations is well documented (Newton and Hausler, 1984), and studies of Portland cement-based well cement corrosion by CO₂ have been conducted by Onan (1984) and Bruckdorfer (1986). It is well known that carbon dioxide–laden waters can destroy the structural integrity of set Portland cements (Biczok, 1967). The basic chemistry describing this process is as follows.

(1) \[ \text{CO}_2 + \text{H}_2\text{O} \leftrightarrow \text{H}_2\text{CO}_3 \leftrightarrow \text{H}^+ + \text{HCO}_3^- \]  

(7-5)

(2) \[ \text{Ca(OH)}_2 + \text{H}^+ + \text{HCO}_3^- \rightarrow \text{CaCO}_3 + 2\text{H}_2\text{O} \]  

(7-6)

(3) \[ \text{C-S-H phase} + \text{H}^+ + \text{HCO}_3^- \rightarrow \text{CaCO}_3 + \text{amorphous silica gel} \]  

(7-7)

In Step 1, approximately 1% of the dissolved carbon dioxide reacts with water to form carbonic acid. As the carbon dioxide–laden water diffuses into the cement matrix, the dissociated acid is free to react with the free calcium hydroxide (Step 2) and the C-S-H phase (Step 3). As carbon dioxide–laden water continues to invade the matrix, other equilibria are established.

(4) \[ \text{CO}_2 + \text{H}_2\text{O} + \text{CaCO}_3 \rightarrow \text{Ca(HCO}_3\text{)}_2 \]  

(7-8)

(5) \[ \text{Ca(HCO}_3\text{)}_2 + \text{Ca(OH)}_2 \leftrightarrow 2\text{CaCO}_3 + \text{H}_2\text{O} \]  

(7-9)

In the presence of excess carbon dioxide (Step 4), calcium carbonate is converted to water-soluble calcium bicarbonate, which can migrate out of the cement matrix. In Step 5, the dissolved calcium bicarbonate can react with calcium hydroxide, forming calcium carbonate and water. The liberated water can then dissolve more calcium bicarbonate. The net result is a leaching of cementitious material from the cement matrix, an increase of porosity and permeability, and a decrease of compressive strength. Downhole, this translates to a loss of casing protection and zonal isolation.

Carbon dioxide corrosion of Portland cements is thermodynamically favored and cannot be prevented. An easy solution to this problem would be a synthetic cement; unfortunately, such systems are not economically feasible for most CO₂-flooding or CO₂-sequestration projects. Instead, the most practical approach is to lower the degradation rate of Portland cement systems.

The cement matrix permeability can be reduced by lowering the water-to-cement ratio, employing controlled particle-size cement technology, adding latex, and adding pozzolanic materials. As discussed in Chapter 3, pumpable Portland cement slurries with densities up to 18.0 lbm/gal [2,161 kg/m³] can be prepared with the addition of a dispersant. After setting, the water permeability of such systems is usually less than 0.001 mD; consequently, invasion of carbon dioxide–laden water is inhibited, and the rate of corrosion is slowed. The addition of pozzolans (such as fly ashes) and latex, as well as controlling the particle-size distribution, also reduces set-cement permeability (Chapter 3) and effectively eliminates Reaction 2 above. When such measures are taken, the corrosion rate can be reduced by as much as 50%.

BFS-Portland cement blends reportedly show improved resistance to CO₂ (Cowan et al., 1994a). This application is discussed further in Section 7-8.2.3. Elastomeric composites based on styrene-butadiene rubber have also been introduced as cements for CO₂-injection wells (Onan et al., 1993; Section 7-11).

The long-term efficacy of the modified Portland cement systems in CO₂-flood wells remains to be seen. Such systems may only postpone the inevitable deterioration. More research is needed to develop truly stable, yet economically viable, cements for this difficult environment.

7-8 BFS systems

The use of BFS systems in well cementing is not a new concept; indeed, patents covering slag-cement compositions for wellbores appeared as early as 1958 (Harmeen and Stuve, 1958). BFSs can be used alone as a cementitious material or blended with Portland cements (called Portland slag cements or slag cements). Slags are also used to convert drilling fluids into a cementitious material. In this case, chemical activators are required to speed up slag hydration kinetics.

The use of BFS for well cementing has increased significantly since the early 1990s. This section discusses the production and chemistry of BFS, as well as the use of BFS in various well-cementing applications.

7-8.1 Production, composition, and hydration of BFS

BFS is a byproduct of steel manufacture. In the operation of a blast furnace, the iron oxide ore is reduced by means of coke to metallic iron, while the silica and alumina constituents combine with the lime and magnesia to form a molten slag that collects on top of the
molten iron in the furnace. The slag issues from the blast furnace as a molten stream at a temperature of 2,462°–2,822°F [1,350°–1,550°C]. If allowed to cool slowly, the slag crystallizes into a material having virtually no cementitous properties. If rapidly cooled to below 1,472°F [800°C], it forms a glass that is a latent hydraulic cement. Cooling is usually effected by spraying droplets of the molten slag with high-pressure water jets. This produces a wet, sandy material that, when dried and finely ground, is called ground granulated blast-furnace slag and often contains more than 95% glass. The slag consists of a silicate network containing calcium, magnesium, and aluminum cations. The crystalline components, which occur as inclusions in the glass, are generally composed of merwinite (C3M2S2) and melilite (a solid solution of gelhenite, C2AS, and akermanite, C2M2S2). The slag composition depends on the original iron ore and can vary widely. However, the slag composition produced from a particular plant is generally consistent unless the ore source changes. Table 7-10 shows the compositions of slags produced in various countries.

7-8.2 BFS-Portland cement blends

During the past decade, the use of BFS for well cementing has increased significantly, notably for squeeze applications (Chapter 14). When BFS is used in combination with Portland cement, special chemical activators are not generally needed, because two slag-hydration activators are already present: gypsum (sulfate activation) and portlandite, Ca(OH)2.

The granulated BFS is blended or interground with Portland cement or a clinker-gypsum mixture. The relative proportions of Portland cement and BFS vary widely; the BFS content can exceed 80%, but less than 50% is more common. These cements are used extensively in civil engineering and are readily available worldwide.

The principal hydration products of BFS-Portland cement blends are similar to those of pure Portland cements, but the quantities of portlandite liberated upon hydration are lower. When the BFS concentration in the blend exceeds 60%, the portlandite content peaks and then decreases with hydration time. The mean bulk lime-to-silica (C/S) ratio of the calcium silicate hydrate (C-S-H) phase is lower than that found in pure Portland cement slurries. For a blend with 50% BFS, C/S values in the region of 1.5 are obtained, compared to 1.8 when BFS is not present.

BFS is a pozzolanic material (Chapter 3) that can react with portlandite to form additional C-S-H at temperatures below 230°F [110°C]. At higher temperatures, the C-S-H phase converts into other crystalline calcium silicate hydrate phases (Chapter 10).

Slag cements are generally more resistant to chemical attack than pure Portland cements. The principal benefits are

- better sulfate resistance
- slower diffusion of chloride and alkali ions through the cement matrix
- lower set-cement permeability.

These performance improvements are the result of changes in the cement-matrix microstructure. When BFS is present, the pore sizes in the set-cement matrix are smaller, and the capillary porosity (pore radii above 300 Å) is lower. The total capillary porosity can be reduced by 25 to 30% when BFS is 75% of the Portland cement mixture.

The pore-size reduction can be attributed to the absence of large portlandite crystals. In addition, when the proportion of slag in the blend is increased, the C-S-H–phase microstructure becomes progressively less fibrillar and more foil-like. The foils encapsulate some of the pores, making them inaccessible to fluids and reducing the set-cement permeability. The lower amount of portlandite, which is more soluble in water than the C-S-H phase, improves the resistance of the set cement to sulfate and chloride attack.

Table 7-10. Oxide Composition (Percentage) of BFS†

<table>
<thead>
<tr>
<th>Source</th>
<th>CaO</th>
<th>SiO2</th>
<th>Al2O3</th>
<th>MgO</th>
<th>Fe2O3</th>
<th>MnO</th>
<th>S</th>
</tr>
</thead>
<tbody>
<tr>
<td>United Kingdom</td>
<td>40</td>
<td>35</td>
<td>16</td>
<td>6</td>
<td>0.8</td>
<td>0.6</td>
<td>1.7</td>
</tr>
<tr>
<td>Canada</td>
<td>40</td>
<td>37</td>
<td>8</td>
<td>10</td>
<td>1.2</td>
<td>0.7</td>
<td>2.0</td>
</tr>
<tr>
<td>France</td>
<td>43</td>
<td>35</td>
<td>12</td>
<td>8</td>
<td>2.0</td>
<td>0.5</td>
<td>0.9</td>
</tr>
<tr>
<td>Germany</td>
<td>42</td>
<td>35</td>
<td>12</td>
<td>7</td>
<td>0.3</td>
<td>0.8</td>
<td>1.6</td>
</tr>
<tr>
<td>Japan</td>
<td>43</td>
<td>34</td>
<td>16</td>
<td>5</td>
<td>0.5</td>
<td>0.6</td>
<td>0.9</td>
</tr>
<tr>
<td>Russia</td>
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<td>34</td>
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<td>9</td>
<td>1.3</td>
<td>1.1</td>
<td>1.1</td>
</tr>
<tr>
<td>South Africa</td>
<td>34</td>
<td>33</td>
<td>16</td>
<td>14</td>
<td>1.7</td>
<td>0.5</td>
<td>1.0</td>
</tr>
<tr>
<td>United States</td>
<td>41</td>
<td>34</td>
<td>10</td>
<td>11</td>
<td>0.8</td>
<td>0.5</td>
<td>1.3</td>
</tr>
</tbody>
</table>

† From Moranville-Regourd (2001). Reprinted with permission from Elsevier.
In addition to mud-to-cement technology, slags and slag cements are used in the following well cementing applications:

- squeeze cementing using microfine cements
- salt-saturated cement slurries
- CO$_2$-resistant cements
- foamed cement
- improvement of construction grade cements in well cementing.

Each application is briefly described below.

**7-8.2.1 Squeeze cementing**

When a casing leak occurs or a poor bond exists between the cement and the casing or formation, a competent repair is necessary to restore wellbore integrity (Chapter 14). Squeeze cementing is a common method. Conventional cement systems are sometimes ineffective, because the fissure or channel to be squeezed is too narrow for the cement grains to penetrate.

Small-particle-size cement systems have been developed for squeeze cementing. These so-called microfine cements include pure Portland cements, BFS, and very often BFS-Portland cement blends (Clarke, 1988; Meek and Harris, 1991; Ewert et al., 1991). The Blaine fineness of microfine cements varies between 6,000 cm$^2$/g and 16,000 cm$^2$/g, compared to about 3,200 cm$^2$/g for Class G cements. The median diameter of cement particles is 2–3 μm, compared to 15–18 μm for Class G cements. The diameter of the largest cement particles must be less than 30 μm and preferably below 10–15 μm. For high-temperature wells, in which the BHST is above 230°F [110°C], silica fume or very fine silica is added instead of silica flour to prevent strength retrogression, because the particle size of silica flour is too large. Effective retarders have been developed to retard microcements at high temperatures. Brothers (1994) described a methylene phosphonate derivative that provides predictable retardation up to about 245°F [118°C]. Rodrigues and Lindsey (1995) described another phosphonate compound that performs reliably at up to 400°F [204°C].

**7-8.2.2 Salt-zone cementing**

The use of BFS for well cementing across salt formations was patented by Cowan et al. (1994b). As discussed in Section 7-5, large quantities of sodium chloride are often added to the mix water (up to saturation, 37% BWOW) when Portland cement slurries are used. This practice prevents dissolution of the salt formation that could result in poor bonding between the cement and formation. Adding such high concentrations of salt to a Portland cement slurry can negatively affect rheology, thickening time, fluid-loss control, and compressive strength. However, in systems containing BFS, sodium chloride can considerably increase the compressive strength of the resultant set cement (Table 7-11).

**Table 7-11. Effect of Salt-Saturated Mix Water on Compressive Strengths of BFS Cement Systems**

<table>
<thead>
<tr>
<th>Slag</th>
<th>Water</th>
<th>Compressive Strength (psi [MPa])</th>
</tr>
</thead>
<tbody>
<tr>
<td>NEWCEM</td>
<td>Fresh</td>
<td>566 [3.9]</td>
</tr>
<tr>
<td>NEWCEM</td>
<td>Salt</td>
<td>977 [6.7]</td>
</tr>
<tr>
<td>KOCH†</td>
<td>Fresh</td>
<td>965 [6.7]</td>
</tr>
<tr>
<td>KOCH‡</td>
<td>Salt</td>
<td>1,453 [10]</td>
</tr>
</tbody>
</table>

† NEWCEM from Blue Circle Cement Company; Blaine specific surface area: 5,500 cm$^2$/g
‡ KOCH from Koch Minerals; Blaine specific surface area: 10,040 cm$^2$/g

Cowan et al. also recommended drilling the wellbore with salt-saturated drilling fluids containing BFS and converting the drilling fluid into a settable cement slurry by adding activators, additional slag, or both. In this case, slag-based cements bond to the casing particularly well owing to the absence of shrinkage upon curing as well as compatibility with drilling fluid remaining on the casing surface (Section 7-8.3). The strength and ductility of slag cements is also improved by inclusion of crosslinkable polymers such as polyacrylamide in the cement slurry.

**7-8.2.3 CO$_2$ resistant cements**

Slag cements are more resistant to carbon dioxide and carbonic acid than Portland cements (Cowan et al., 1994a). Portland cements gradually degrade while exposed to carbon dioxide because of the transformation of calcium silicate hydrates into calcite and silica gel (Section 7-7). In addition, carbonic acid can interfere with the setting of Portland cement slurries. The improved resistance of slag cements is most likely caused by the lower matrix permeability.

**7-8.2.4 High-pressure, high-temperature gas wells**

BFS cements have been used successfully to cement high-pressure, high-temperature gas wells in South Texas, USA (Sweatman et al., 1995). They are especially suitable for obtaining shorter waiting-on-cement times at the top of cement, where temperatures are lower than BHCTs. Slag systems have excellent shear-bond strengths under simulated downhole conditions, and previously broken shear bonds seem to regenerate or
heal with time. The shear bond provided by the slag system improves with time at elevated temperatures and has much better bond regeneration properties than Class H cement (Table 7-12). The superior rebonding or healing performance of slag may be linked to the development of internal stresses caused by a densified microstructure and other mechanisms that are not yet well understood. Slag systems have also maintained zonal isolation after exposure to high pressures during hydraulic fracture treatments.

7-8.2.5 Foamed cements

Chatterji et al. (1998) showed that slags could be used in foam cement. The slag has a Blaine fineness of 5,900 cm$^2$/g, and is activated with sodium carbonate. The slurry density varies from 6 to 16 lbm/gal [720 to 1,921 kg/m$^3$], depending on foam quality. The cement compositions are particularly suitable for primary cementing operations because they are lightweight and compressible and have excellent fluid-loss control, short transition times, and good thermal insulation properties. A thorough discussion of foamed cements is presented in Section 7-10.

7-8.2.6 Steam injection

Blanco et al. (1999) performed a comparative study of BFS cements and Portland cements for steam injection wells. After enduring thermal shocks to simulate the steam-injection process, the BFS systems exhibited better thermal stability and compressive strength, and lower water permeability, than the corresponding Portland cement systems. The BFS cements expanded after thermal shock. As a result, the cement bond logs indicated superior zonal isolation compared to those completed with Portland cement. The authors concluded that BFS systems are more suitable for steam injection wells. More information about cementing steam-injection wells is presented in Chapter 10.

### Table 7-12. Ambient and High-Temperature Shear Bonds

<table>
<thead>
<tr>
<th>Slurry Composition</th>
<th>Salt-Saturated Class H</th>
<th>Freshwater Slag Cement</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>lbm/bbl</td>
<td>lbm</td>
</tr>
<tr>
<td>Class H</td>
<td>325</td>
<td>94</td>
</tr>
<tr>
<td>Slag</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Hematite</td>
<td>38</td>
<td>11</td>
</tr>
<tr>
<td>Silica flour</td>
<td>113</td>
<td>32</td>
</tr>
<tr>
<td>Salt</td>
<td>49</td>
<td>18.7</td>
</tr>
<tr>
<td>Organic additives</td>
<td>9.6</td>
<td>2.8</td>
</tr>
<tr>
<td>Surfactant</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Soda ash</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Fresh water</td>
<td>173</td>
<td>50.2</td>
</tr>
<tr>
<td>Water requirement, gal/sk</td>
<td>6.0</td>
<td>6.0</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>First Test</th>
<th>Second Test</th>
<th>Average</th>
<th>First Test</th>
<th>Second Test</th>
<th>Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shear bond, psi (280°F/1,000 psi)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Initial, 8-day</td>
<td>152</td>
<td>158</td>
<td>155</td>
<td>122</td>
<td>158</td>
</tr>
<tr>
<td>Retest, 14-day</td>
<td>109</td>
<td>90</td>
<td>100</td>
<td>191</td>
<td>164</td>
</tr>
<tr>
<td>Change (%)</td>
<td>–28</td>
<td>–43</td>
<td>–36</td>
<td>57</td>
<td>4</td>
</tr>
<tr>
<td>Regenerated</td>
<td>36</td>
<td>44</td>
<td>40</td>
<td>117</td>
<td>118</td>
</tr>
</tbody>
</table>

Lower section shear bond, psi

| Ambient conditions | 442 | 460 | 451 | 560 | 588 | 574 |

$^1$ For 17-lbm/ gal [2,141 kg/m$^3$] salt-saturated Class H and freshwater slag-cement slurries measured on high-pressure, high-temperature shear-bond tester (from Sweatman, 1995). Reprinted with permission of SPE.

$^2$ Regenerated shear bond = 14-day shear bond + 8-day skin
7-8.2.7 Treatment of construction cements

Mueller et al. (1995) showed that blending BFS with construction-grade Portland cements can produce a high-quality well cement. The blends have fluid-loss, free-water, and compressive-strength properties comparable to, and sometimes better than, Portland cements (Table 7-13). With construction-grade cements, a slag/Portland cement blend produces a more linear response to lignosulfonate retarders (Di Lullo Arias, 1996). The BFS concentration can vary from 10% to 200% BWOC. The BFS alters the chemical and physical properties of construction-grade cement such that the compressive strengths and thickening times meet API and International Organization for Standardization (ISO) standards. Construction-grade cements could not otherwise be used for well cementing because of their unpredictability from brand to brand and their failure to meet the API/ISO standards. The lower cost of construction-grade cement decreases the cost of well cementing operations, especially in remote areas to which API/ISO oilwell cements must be imported.

### Table 7-13. Performance of Some Construction Cements Modified with BFS†

<table>
<thead>
<tr>
<th>Slurry Designs</th>
<th>Composition</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1 Gas Slurry</td>
</tr>
<tr>
<td>BFS:PC ratio†</td>
<td>0.6:1</td>
</tr>
<tr>
<td>PVAP†† (%BWOW)</td>
<td>15</td>
</tr>
<tr>
<td>LMS§§ (gal/sk)</td>
<td>2.5</td>
</tr>
<tr>
<td>Dispersant (gal/sk)</td>
<td>0.05</td>
</tr>
<tr>
<td>Liquid Na Silicate (gal/sk)</td>
<td>_</td>
</tr>
<tr>
<td>BASS††† (gal/sk)</td>
<td>0.5</td>
</tr>
<tr>
<td>CaCl₂ (%BWOC)</td>
<td>2.5</td>
</tr>
<tr>
<td>Density (lbm/gal)</td>
<td>11.7</td>
</tr>
<tr>
<td>BHST (°F)</td>
<td>145</td>
</tr>
<tr>
<td>BHCT (°F)</td>
<td>115</td>
</tr>
</tbody>
</table>

### Test Results

<table>
<thead>
<tr>
<th>Test Results</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
<th>8</th>
</tr>
</thead>
<tbody>
<tr>
<td>Thickening time (min)</td>
<td>375</td>
<td>390</td>
<td>248</td>
<td>370</td>
<td>202</td>
<td>161</td>
<td>260</td>
<td>300</td>
</tr>
<tr>
<td>Fluid loss (mL/30 min)</td>
<td>25</td>
<td>186</td>
<td>94</td>
<td>na</td>
<td>32</td>
<td>39</td>
<td>na</td>
<td>252</td>
</tr>
<tr>
<td>Free fluid (%)</td>
<td>Trace</td>
<td>0.5</td>
<td>Trace</td>
<td>0.5</td>
<td>Nil</td>
<td>Nil</td>
<td>0.4</td>
<td>Trace</td>
</tr>
<tr>
<td>Compressive strength (psi/24 hr)</td>
<td>1,150</td>
<td>370</td>
<td>3,150</td>
<td>400</td>
<td>425</td>
<td>2,350</td>
<td>1,220</td>
<td>3,650</td>
</tr>
<tr>
<td>μp/τ</td>
<td>18/10</td>
<td>14/9</td>
<td>56/14</td>
<td>22/8</td>
<td>24/9</td>
<td>24/10</td>
<td>10/3</td>
<td>64/10</td>
</tr>
</tbody>
</table>

†† From Mueller et al. (1995). Reprinted with permission of SPE.
† Density of BFS = 5 lbm/ft³
§ Portland cement = ASTM Type I
†† Polyvinyl acetate phthalate
†‡ Not present
§§ Liquid microsilica
††† Blend of aluminum salts and surfactant
‡‡‡ Producing steam temperature
§§§ not applicable
7-8.3 Cementitious drilling fluids

Since the early 1990s, there has been considerable interest in converting drilling fluids into a cementitious material for well cementing. Such technology has several potential advantages (Cowan et al., 1992).

- Better mud removal
- Less effect of mud contamination on the performance of the well cement, owing to greater compatibility between the two fluids
- Potential solidification of both the mud filtercake and undisplaced mud
- Reduction of mud disposal volume (Nahm et al., 1993)

Two principal systems have been developed. The first involves treating the mud with special copolymer dispersants and accelerators and then adding cement (Wilson et al., 1989; 1990; Bloys et al., 1991). The second consists of mixing BFS and a water-base mud that has been diluted, conditioned, and pretreated with a chemical activator for the BFS (Hale and Cowan, 1991; Cowan and Hale, 1994; Hale, 1996; Cowan et al., 1996; Hale and Cowan, 1997).

Other patented systems include drilling fluids comprising condensed silica fume activated by alkalis (Terry et al., 1994; Onan et al., 1994), oil-base mud conversion using BFS (Nahm and Wyant, 1993), and drilling fluids containing monomers that are polymerized by chemical activation or irradiation (Novak, 1988). In all of these cases, elaborate and time-consuming pretreatment of the mud is required before adding cementitious material.

During the last decade, BFS-drilling fluid systems have been used in cementing operations, including primary cementing jobs, temporary abandonment plugs, and sidetracking plugs. Up to 500 lbm [227 kg] of BFS can be added per barrel of pretreated drilling fluid. This system has a wide application range. Slurry densities can vary from 10 to 20 lbm/gal [1,200 to 2,400 kg/m³], and the application temperature can vary from ambient to about 392°F [200°C]. Hale and Cowan (1991) found that, unlike Portland cement, BFS does not significantly affect mud properties. BFS can also be added during drilling to ensure that the mud filtercake contains a cementitious material and will harden once chemically activated (Table 7-14).

### Table 7-14. Typical Performance of Mud-to-Cement Systems†, ‡

<table>
<thead>
<tr>
<th>Component or Property</th>
<th>560 m²/kg Fineness BFS</th>
<th>1,100 m²/kg Fineness BFS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial density of mud (lbm/gal)</td>
<td>10.3</td>
<td>10.3</td>
</tr>
<tr>
<td>Amount of slag added (lbm/bbl)</td>
<td>300</td>
<td>300</td>
</tr>
<tr>
<td>Amount of sodium hydroxide added (lbm/bbl)</td>
<td>10</td>
<td>6</td>
</tr>
<tr>
<td>Amount of sodium carbonate added (lbm/bbl)</td>
<td>10</td>
<td>6</td>
</tr>
<tr>
<td>Final density of mixture (lbm/gal)</td>
<td>13.3</td>
<td>13.3</td>
</tr>
<tr>
<td>Thickening time at 90°F</td>
<td>5:00+</td>
<td>5:00+</td>
</tr>
<tr>
<td>Free water at 80°F (mL)</td>
<td>1.5</td>
<td>1.5</td>
</tr>
<tr>
<td>Compressive strength, psi, at 80°F after:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>8 hr</td>
<td>185</td>
<td>Not set</td>
</tr>
<tr>
<td>12 hr</td>
<td>450</td>
<td>100</td>
</tr>
<tr>
<td>24 hr</td>
<td>945</td>
<td>1,685</td>
</tr>
<tr>
<td>48 hr</td>
<td>1,370</td>
<td>2,690</td>
</tr>
</tbody>
</table>

† From Cowan et al. (1992).
‡ For solidification of salt-saturated/starch mud

7-8.3.1 Mud-to-cement process

The mud-to-cement process involves several steps. First, the drilling fluid to be converted is isolated. Second, the drilling fluid is diluted with water to obtain a specific final slurry density or for rheological control. In most cases, the mud must be diluted by 60% or more to accommodate slag into the system (Benge and Webster, 1994). This minimizes the volume of mud that can be converted. Third, other additives such as retarders, dispersants, and slag activators are added. Finally, the treated drilling fluid is transferred to the cementing unit, slag is added, and the mixture is then pumped down the well.

7-8.3.2 Mud-to-cement performance

Song et al. (2000), Leimkuhler et al. (1994), Nahm et al. (1995), and Dahua et al. (1998) reported that adding BFS to mud can not only provide good-quality cement jobs in normal wells, but also is very useful for solving gas-migration and lost-circulation problems. Using cement bond logs as the principal criterion, these authors reported that the success rate of wells completed with mud-to-cement systems was frequently better than that of conventional cement systems.
Several limitations surrounding this technology have been reported (Saasen et al., 1994, Benge and Webster, 1994; Mueller and Dickerson, 1994; Sabins et al., 1996). In laboratory testing, microfractures have been observed in the set cement. The cause of the microfractures is unclear. It is also unknown whether the microfractures occur in the well in which the cement is confined. Benge and Webster (1994) observed that, unlike set Portland cement, set drilling fluids containing slag have no fibers or crystals connecting the grains. They concluded that the set material is less deformable and has a greater tendency to crack. However, Silva et al. (1997) did not observe microcracks after testing at high temperature and pressure. They concluded that BFS–drilling fluid systems can be used successfully in high-temperature conditions.

Mueller and Dickerson (1994) showed that overactivation of slag-based systems produces several detrimental effects, including abnormal thickening-time response, excessive heat buildup, high mixing viscosities, and diminished compressive strength owing to stress cracking. They suggested that, when the activator system contains sodium hydroxide, stress-cracking and brittleness result.

Another important issue is the design complexity of BFS-based mud-to-cement systems. Unlike a conventional cement system, the composition of a drilling fluid can vary widely as drilling progresses. The composition of the cuttings changes as the drill bit penetrates different formations, each with different chemical environments, and chemicals are continually added by mud engineers to maintain the desired properties. Such chemicals can strongly affect thickening time, rheology, and compressive strength. Therefore, to properly design a BFS–drilling fluid cement system, the testing laboratory must receive a mud sample that is representative of the material that will be available for conversion. For this reason, long before the cementing treatment, a large volume of mud is usually isolated from the active system, allowing the laboratory sufficient time to design an appropriate slurry.

The addition of BFS to drilling muds can substantially increase fluid viscosity and result in severe flocculation. Conventional drilling-fluid dispersants do not necessarily disperse cement slurries. However, several suitable dispersants have been patented (Bloys et al., 1994; Carpenter and Johnson, 1999). A styrene sulfonic acid-maleic anhydride copolymer, recently developed by Hou and Liu (2000), is an effective dispersant for mud-to-cement technology.

### 7-9 Engineered particle-size distribution cements

#### 7-9.1 Introduction

As discussed in Chapter 3, cement-slurry properties depend on many variables: the amount and properties of solids (including cement), the additives, the amount and type of mix water, temperature, and pressure. Achieving optimal cement performance can be difficult at the extremes of the slurry-density range. At slurry densities above 17.5 lbm/gal (2,101 kg/m³), designing a stable and pumpable slurry can be difficult. In the low-density range [less than 14.0 lbm/gal (1,680 kg/m³)] achieving rapid compressive strength development and high final compressive strength can be challenging. In conventional well cement systems, the slurry density is traditionally adjusted by varying the water-to-solids ratio or by adding weighting agents or low-density extenders. This section presents a more sophisticated design method that considers the particle-size distribution of the solids in the cement slurry.

The civil engineering industry uses the concept of particle packing to prepare high-performance concrete (de Larrard, 1989; de Larrard and Sedran, 1994). By increasing the packing density of solids in the dry blend, the amount of water necessary to prepare a pumpable slurry decreases (Mooney, 1951). As a result, the set cement is stronger and less permeable. This technology has recently been adapted for well cementing applications.

#### 7-9.2 Engineered particle-size concept

In conventional cements, the slurry and set-cement properties depend on the slurry density (water-to-solids ratio) and the additives. For engineered particle size (EPS) cement systems, the slurry and set-cement properties depend on the following:

- properties of the solids
- packing volume fraction (PVF or \( f_{PV} \)) of the solids
- solid volume fraction (SVF or \( f_{SV} \)) of the resulting slurry.

In a powder, the PVF is defined as the volume of space occupied by the solid particles (the absolute volume) divided by the total volume of solid particles plus the void space between them (the bulk volume).

\[
f_{PV} = \frac{\left( V_{a} \right)_{solids}}{V_{bulk}}
\]

(7-10)
The packing of a powder is a purely geometrical phenomenon. Therefore, the PVF depends only on the size and the shape of the particles. A perfect arrangement of spheres with the same size (compact hexagonal packing) has a PVF of 0.74 (Cumberland and Crawford, 1987). A random packing of the same spheres has a PVF of 0.64. In other words, the solids occupy 64% of the bulk volume, and the void space occupies 36% of the bulk volume.

Higher PVFs can be achieved by preparing powders with solids that have more than one particle size (i.e., a polydisperse mixture). The smaller particles fit in the void spaces between the larger ones. From geometry, if the smaller particles are more than 10 times smaller, and they are all the same size (i.e., monodisperse), they can fill 64% of the void. Hence, the PVF would be

$$f_{PV} = \frac{0.64 + (0.36 \times 0.64)}{1.0} = 0.87. \quad (7-11)$$

The PVF can be maximized by using coarse, medium, and fine particles in specific volumetric ratios. As shown in Fig. 7-14, the fine particles fit in the void space between the medium-size particles, and the medium-size particles fit in the void space between the coarse particles. For two consecutive granulometric classes, the order of magnitude between the mean particle diameter ($d_{50}$) of each class should ideally be between 7 and 10. In such cases, the PVF increases to 0.95. The PVF calculation should also take the particle shapes into account, but this parameter is not considered in most mathematical models.

The solid volume fraction (SVF) is the ratio between the volume of solids in a slurry and the total slurry volume (solids + mix water).

$$f_{SV} = \frac{V_{solids}}{V_{slurry}} \quad (7-12)$$

The volume of mix water divided by the total slurry volume is the slurry porosity ($\phi$).

$$\phi = \frac{V_{water}}{V_{slurry}} \quad (7-13)$$

As shown in Eq. 7-14, the slurry density ($\rho_{slurry}$) is adjusted by varying the porosity for a given blend of solids with density $\rho_b$ (Maroy and Baret, 1994; Baret et al., 1996; Noik et al., 1998).

$$\rho_{slurry} = \rho_b (1 - \phi) + \phi \rho_{mw} \quad (7-14)$$

Or, expressed in terms of SVF, $p_{mw} = \text{mix water density}$.

$$\rho_{slurry} = \rho_b \times f_{SV} + (1 - f_{SV}) \rho_{mw}. \quad (7-15)$$

In addition to affecting slurry density, the SVF influences the cement-slurry and set-cement properties in the following ways.

- Thickening time (the lower the SVF, the longer the thickening time)
- Compressive strength (the higher the SVF, the higher the compressive strength)
- Stability (the higher the SVF, the better the slurry stability)
- Fluid loss (the higher the SVF, the lower the fluid-loss rate)
- Rheology (the higher the SVF, the higher the slurry viscosity)

### 7-9.3 EPS slurry design

The SVF of a neat, 15.8-lbm/gal [1,897 kg/m³] Class G slurry is 0.41 (or, $\phi = 0.59$). Maximizing the PVF of the solids reduces the amount of water required to prepare a pumpable slurry. In most cases the optimal SVF in EPS slurries is 0.55 to 0.60 (or, $\phi$ from 0.40 to 0.45). Within such a narrow SVF range, EPS slurry design relies on only two parameters: the particle-size distribution and the specific gravities of the blend components. As a result, EPS cement systems have several advantages over conventional cement systems.

- The slurry rheology is significantly less dependent on the slurry density.
- The compressive strength and permeability of the set cement are significantly less dependent on the slurry density.
- The slurry is more stable.
- Better fluid-loss control is achieved.

### 7-9.3.1 Slurry density
To achieve a given slurry density, engineers choose a blend of solids with a given specific gravity (Eq. 7-16).

\[
\rho_b = \left[ \rho_{\text{slurry}} - \phi \rho_{\text{new}} \right] / (1 - \phi).
\]  
(7-16)

where

\( \rho_b \) = blend density.

Table 7-15 presents some common cement-slurry solids with various specific gravities, organized according to their position in the trimodal-particle-size scheme.

Assuming that the particles in the blend are spherical, it is possible to achieve PVFs as high as 0.88. The available selection of particles allows one to prepare stable EPS slurries at densities from 8.0 to 23.0 lbm/gal [960 to 2,761 kg/m³].

### 7-9.3.2 Slurry rheology
The rheology of a concentrated suspension depends on the packing behavior of the particles. At PVFs as high as 0.88, the resulting slurries have low plastic viscosities across the slurry density range (Table 7-16).

For a given SVF, \( \tau_y \) decreases as the concentration of dispersant increases. This is also true for conventional slurries (Chapter 3). Using a dispersant is important in EPS slurries to prevent agglomeration of the fine particles. The \( \tau_y \) of most EPS slurries is usually less than 20 lbf/100 ft².

### 7-9.3.3 Slurry stability: free water and segregation
Free water and segregation arise from particle interaction in the cement slurry (Chapter 3; Appendix B). Often, to achieve a certain slurry density, coarse particles with a low specific gravity (e.g., ceramic microspheres) or a very high specific gravity (e.g., hematite) must be used. Such particles can be very difficult to stabilize in conventional cement slurries. As shown by Stokes’ law (Eq. 7-17), the settling velocity of a particle is more dependent on its size than its specific gravity.

\[
v = \frac{g \times (\rho - \rho_L) \times d^2}{18 \mu_L},
\]  
(7-17)

where

\( d \) = particle diameter
\( g \) = acceleration of gravity
\( v \) = settling velocity
\( \mu_L \) = viscosity of liquid medium
\( \rho \) = specific gravity of particle
\( \rho_L \) = specific gravity of liquid medium.

For example, the specific gravities of hematite and silica sand are 4.8 and 2.6. According to Stokes’ law, for a given particle size, the hematite particle would settle about twice as fast as the silica particle. However, for a given particle density, if particle size is increased to 500 \( \mu \)m from 1 \( \mu \)m, the settling rate increases by a factor of 250,000.
Stokes law considers a single particle that can fall unobstructed through the liquid medium. A cement slurry is a concentrated suspension that tends to behave as a porous solid that may shrink under the force of gravity. Such behavior is also called hindered settling, and this effect increases with the particle concentration or SVF. As the SVF approaches 60% in EPS slurries, the hindered settling effect is more pronounced compared to conventional slurries; consequently, it is easier to prepare a stable system.

In concentrated slurries of uniformly sized spheres, the settling velocity is given by the following equation.

\[ v_s = v(1 - f_{SV})^n, \]  

(7-18)

where

- \( n \) = an experimentally determined value (usually 5) (Richardson and Zaki, 1954)
- \( v \) = single particle settling velocity
- \( v_s \) = settling velocity in concentrated slurry

### 7-9.3.4 Additives

Although EPS cement systems have a high solids content, most of the particles are chemically inert. Compared to conventional cement systems, the cement concentration is very low—between 20 and 50% by volume of blend. Consequently, the amounts of retarders and dispersants in the cement slurry are also lower. Owing to the lower amount of water in EPS systems and the ability of solids to achieve maximum compactness, the amount of fluid-loss-control agent required to achieve a given fluid-loss rate is roughly half that of conventional slurries (Baret et al., 1996; Villar et al., 2000).

### 7-9.4 Performance of EPS cement systems

The slurry porosity reduction allowed by blend optimization has a beneficial effect on the properties of the set material, particularly at the upper and lower ranges of the slurry-density scale (Moulin et al., 1997).

#### 7-9.4.1 Low-density systems

The slurry porosity of conventional low-density cement systems is typically high, and such slurries often contain extenders such as bentonite and fly ash (Chapter 3). The higher water-to-cement ratio can lead to slurry-stability problems, and the compressive strength and permeability are usually compromised.

The reduced slurry porosity of EPS slurries ensures early compressive-strength development and a higher ultimate compressive strength (Fig. 7-15) (Revil and Jain, 1998; Rucker et al., 2001). Figure 7-16 shows that, at very low slurry densities, EPS slurries develop more compressive strength than foamed cements. The lower permeability of EPS slurries, combined with the presence of inert fillers in the blend, also improves the chemical resistance of the set cement. Figure 7-17 illustrates the resistance of various cement systems to mud acid (a mixture of HCl and HF). The EPS blends are significantly more resistant, particularly when latex is present in the formulation.

![Fig. 7-15. 24-hr compressive strengths of 12.0-lbm/gal [1,440 kg/m³] cement systems.](image)

![Fig. 7-16. 24-hr compressive strengths foamed cements and EPS cements at various densities.](image)

![Fig. 7-17. Solubility of various cement systems in mud acid. Weight loss (%) after 24 hr exposure at ambient temperature.](image)
Some low-density EPS systems are tailored for low-temperature applications such as deepwater wells. The reactivity is enhanced by using microcement as fine particles. The high reactivity of the microcement significantly improves compressive-strength development (Michaux et al., 1998; Piot et al., 2001) (Fig. 7-18). Similar properties have been achieved using a high-alumina cement. Such systems develop compressive strengths above 3,000 psi [21 MPa] within 24 hr at 40°F [4°C] (Villar et al., 2000).

### 7.9.4.2 High-density systems

Conventional heavyweight slurries are prepared by adding weighting agents, decreasing the amount of cement and water, and adding a dispersant to maintain pumpability. Because a minimum amount of cement is required to achieve sufficient compressive strength, there is a limitation on the upper slurry density. In addition, such slurries tend to be unstable. Because the EPS design method allows the slurry viscosity to remain low at high SVFs, more cement can be added to blend. As a result, high compressive strength can be maintained (Jain et al., 2000; Pokhriyal et al., 2001).

The performance of high-density EPS cement systems is illustrated in Figs. 7-19 and 7-20. Figure 7-19 compares the friction pressure that is observed when 19.0-lbm/gal [2,280 kg/m³] conventional and EPS cement systems are pumped through pipe at various pump rates. Less friction pressure develops when EPS systems are pumped.
Use of heavy particles allows EPS systems to achieve slurry densities up to 23 lbm/gal [2,761 kg/m^3]. The water-to-cement ratio is still low, ensuring a rapid development of compressive strength.

**7-10 Ultralow-density cement systems**

Formations that have a low fracturing gradient or are highly permeable, vuggy, or cavernous pose difficult cementing situations. Such formations are often unable to support the annular hydrostatic pressure exerted by a conventional cement slurry. Some formations will not even support a column of water. The density of conventional cements mixed with water always exceeds 8.33 lbm/gal [1,000 kg/m^3]. In reality, the density of conventional systems with acceptable properties usually exceeds 11 lbm/gal [1,320 kg/m^3]. Therefore, there are situations in which it is impossible to perform a successful cement job with a conventional slurry.

Ultralow-density cements provide a solution to such problems. In general, the ultralow-density category refers to systems with densities less than about 10 lbm/gal [1,200 kg/m^3].

**7-10.1 Microsphere and EPS systems**

Hollow glass microspheres and cenospheres are frequently used as extenders to prepare ultralow-density cement systems. In addition, ultralow-density EPS systems that incorporate microspheres and cenospheres are commonly used. Such systems are described in detail elsewhere in this textbook (Chapters 3 and 10, and Section 7-9 in this chapter).

**7-10.2 Foamed cements**

Foamed cements are coarse dispersions of a base cement slurry, a gas (usually nitrogen), a foaming surfactant, and other materials to provide foam stability. The base cement slurry is usually a conventional 15–16 lbm/gal [1,800–1,920 kg/m^3] system. The density of nitrogen is, for all practical purposes, 0 lbm/gal. Therefore, the foam density is adjusted by varying the nitrogen concentration. Although foamed cement was first used by the construction industry more than 60 years ago, its first application in well cementing occurred in 1979. Foamed cementing technology has been evolving ever since.

Montman et al. (1982) reported useful properties at densities as low as 3.5 lbm/gal [0.420 kg/m^3]. Slaton (1981) reported the use of foamed cement at densities as low as 5.0 lbm/gal [600 kg/m^3] in situations in which compressive strength and permeability were not critical.

Foamed cement has several advantages in addition to its low density:

- relatively high compressive strength developed in a reasonable time
- less damaging to water-sensitive formations (Bozich et al., 1984; Bour and Vennes, 1989)
- lower chance of annular gas flow (Tinsley et al., 1980; Hartog et al. 1983)
- ability to cement past zones experiencing total losses.

Also, because the gas has little effect on placement properties such as thickening time, the system density can be adjusted during the cement job by simply changing the gas concentration.

The low density of foamed cements reduces losses to potential producing zones, and increased well productivity may result (Colavecchio and Adamiak, 1987). More recent applications of foamed cements include controlling shallow flows below the mudline in deepwater wells, deterring compaction damage in soft formations, and resisting damage from external stresses placed on the cement sheath.

**7-10.2.1 Foam stability and structure**

The stability of foamed cement is affected by the foaming agent, the quantity of gas, the chemical and physical composition of the slurry, thermodynamic factors, and the mixing method and conditions. Stable foams exhibit spherical, discrete, disconnected pore structures with a clearly defined cement matrix. Unstable foams have nonspherical and interconnected pores, caused by the rupture and coalescence of gas bubbles. Such unstable foams have a sponge-like structure and develop lower compressive strength, higher permeability, and inferior bonding properties.

Foams are categorized by their quality (**Q** _foam_), or the ratio of the volume occupied by the gas to the total volume of the foam (expressed as a percentage) (Eq. 7-19).

\[
Q_{foam} = \frac{V_{gas}}{V_{foam}} \times 100
\]  

(7-19)

As the foam quality varies, two structural situations occur. Concentrated foams are mostly gas phase and consist of polyhedral gas cells separated by thin liquid films. Dilute foams consist of nearly spherical bubbles.
separated by thick liquid films. Foamed cement belongs to the second category, with a quality not exceeding 80% and usually less than 50%.

Foamed cement is a compressible fluid; consequently, owing to hydrostatic-pressure variations, the foam quality, and therefore the density, changes as the foam circulates in the well. $Q_{\text{foam}}$ decreases and density increases as the foam moves from the surface to the bottom of the casing. As the foam moves back up the annulus, $Q_{\text{foam}}$ increases and density decreases. The density can be predicted as a first approximation by considering the compressibility laws and the solubility of nitrogen in the base slurry.

Foamed cement is a three-phase system (gas/liquid/solid), with many phenomena occurring at the interfaces. This system is in constant evolution because of the reorganization of gas bubbles that may grow, shrink, or coalesce, and because of the chemical reactions that occur in the base cement slurry. Foams are difficult to characterize because they are shear history-dependent fluids, and their texture is strongly affected by the mixing procedure. Foamed cements made under large-scale field conditions, with high shear rates and high pressure, have been found to be more stable than foamed cements made under laboratory conditions (Davies et al., 1981). More recently, de Rozières and Ferrière (1991) showed that foamed cement generated in the laboratory at 1,000 psi [7 MPa] is more stable and has a narrower bubble-size distribution than slurries generated at atmospheric pressure (Fig. 7-21).

The most common method to prepare foamed cement at the wellsite is to mix a base cement slurry with all the additives except the surfactants and then inject the surfactants and the gas as the slurry is being pumped downhole (Chapter 13). In addition to the pressure at which foam is generated, the foam-generating equipment can influence the stability and bubble-size distribution of the foamed cement.

The solids play a significant role in foam stabilization (Davies et al., 1981). When a solid particle adheres to a bubble, it inhibits bubble coalescence and enhances foam stability (Sharma et al., 1982). The foam stability is related to the size of the particle and its wettability. The manner by which solid particles are retained at a liquid/gas interface is analogous to the adsorption of solute molecules. In both cases, work is required to transfer the material off the surface and into the bulk solution. This work of desorption is the phenomenon that confers thermodynamic stability to the foam. In the case of finely divided solids, Ross (1969) reported that stability is improved by a reduction in the particle size.

Thermodynamic properties also affect foam stability (de Rozières and Ferrière, 1991). Some of the principal thermodynamic parameters are listed in Table 7-17. For more detailed discussions of foam thermodynamics, the reader is referred to the following references: Davies and Rideal, 1963; Harris, 1985; Manev, 1974; Monsalve and Schechter, 1984; and Sanchez, 1987.

![Fig. 7-21. Structures and bubble-size distributions of foamed cements prepared at two pressures (from de Rozières and Ferrière, 1991). Foamed cement prepared at 1,000 psi [7 MPa] is more stable than that prepared at atmospheric pressure. Reprinted with permission of SPE.](image)
Early in the development of foamed cementing, suitable base-slurry compositions to prepare foamed cements were limited. Today, with improved surfactants and foam generating equipment, virtually any base slurry can be foamed. In addition, more sophisticated laboratory testing equipment is available (Appendix B).

### 7-10.2.2.1 Cement, foaming agents, stabilizers, and additives

A stable base slurry is a prerequisite for a stable foamed cement system. The same mechanisms that produce free fluid or solids segregation will contribute to the destabilization of foamed cements.

The selection of the base slurry density depends on the required set-foamed-cement properties. Normal-density base slurries will lead to higher compressive strengths. However, such slurries require larger volumes of gas to achieve a given foam density; therefore, the resulting permeabilities will be higher. Conversely, less dense base slurries (prepared using lightweight filler materials) require less gas and will produce foamed cements with lower permeabilities; however, the compressive strengths will be lower.

To select suitable foamers and stabilizers for cement, one should consider the following criteria:
- safety and handling considerations
- compatibility
- effect on the cement strength and permeability
- stability
- efficiency
- cost.

The chemicals used to generate and stabilize the foamed cement must be effective at elevated temperatures and pressures and in the highly alkaline, calcium-containing aqueous phase of a cement slurry. Common foaming agents include ethoxylated alcohols and quaternary ammonium salts of fatty acids. Common stabilizers include polyglycol ethers and sulfate salts that impart some thixotropy to the base slurry (Section 7-1).

The duration of foam stability must be longer than the setting time of the base slurry (Hengst and Tressler, 1983). In addition to the base slurry, foaming agent, stabilizers, and additives, one must use a gas that is inert with respect to the cement properties (e.g., nitrogen) and a foam generator with sufficient energy and mixing action (Chapter 13).

### 7-10.2.2.2 Foamed cement properties

Laboratory testing of foamed cement under simulated downhole conditions is difficult. Because of the pressure and temperature dependence of the foam volume, curing a foamed cement at high pressure and temperature requires different equipment than that used for conventional slurries (Appendix B). Work by de Rozières and Ferrière (1991) showed that varying the pressure and mixing conditions during foam preparation can strongly affect compressive strength and permeability. This is presumably caused by differences in the bubble-size distribution of the resulting foam.

#### Stability

The stability must be tested to ensure that the gas will not break out of the slurry. If the gas coalesces and the size of the bubbles increases, gas pockets form and rise in the cement column, resulting in uncemented sections or channels in the well. A simple test to evaluate stability involves slicing a column of set foamed cement into wafers of equal size. The weight of each wafer should be the same in a stable system.

#### Compressive strength and permeability

When the density of conventional cement slurries is reduced by adding water or other extenders, the amount of cementitious material is diluted. Because of the large density difference between water and gas, much less gas is required to reduce the density by an equal amount. Using gas results in less dilution and, therefore, less impact on cement properties. Consequently, the physical properties of foamed cements are similar to those of conventional lightweight cements that are 2 to 4 lbm/gal (240 to 480 kg/m³) heavier (Tanner and Harms, 1983; Smith et al., 1984).

Compressive strength and permeability are frequently tested using slurries containing the same volume percent of gas that would exist in the slurry under downhole conditions but cured at atmospheric pressure. De Rozières and Ferrière (1991) showed that the results can be misleading, and they developed equipment to generate and cure foamed cement under higher pressures (Figs. 7-22 and 7-23).

To generate foamed cement, nitrogen is injected into the lower chamber while the base slurry is pumped through the mixing chamber and the test-cell loop.

---

**Table 7-17. Thermodynamic Parameters that Affect Foam Stability**

<table>
<thead>
<tr>
<th>Stabilizing Phenomena</th>
<th>Destabilizing Phenomena</th>
</tr>
</thead>
<tbody>
<tr>
<td>Laplace diffusion</td>
<td>Gravity drainage</td>
</tr>
<tr>
<td>Plateau border suction</td>
<td>Surfactant concentration gradient</td>
</tr>
<tr>
<td>Marangoni effect</td>
<td>Gibbs elasticity</td>
</tr>
<tr>
<td>Surface viscosity</td>
<td></td>
</tr>
</tbody>
</table>

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Nitrogen is injected until the desired test pressure is attained. Foam quality is determined by the ratio of slurry to the total volume in the circulating loop. The test cell can be used to cure specimens for testing compressive strength, permeability, or other properties. The foamed cement slurry can also be injected into a fluid-loss cell.

Starting with normal-density Class C and Class G cement base slurries, de Rozières and Ferriere (1991) prepared foamed cement and determined the compressive strengths after curing them 72 hr at 80°F [27°C]. From each base slurry, foams with broad and narrow bubble-size distributions were generated. The results, shown in Table 7-18, clearly show the benefits of having a broad bubble-size distribution. Throughout the slurry-density range, a broad bubble-size distribution leads to higher compressive strength. The effect of bubble-

<table>
<thead>
<tr>
<th>Table 7-18. Performance of Foamed Cements Prepared at Various Densities and Bubble-Size Distributions†</th>
</tr>
</thead>
<tbody>
<tr>
<td>Class C Base Slurry</td>
</tr>
<tr>
<td>Curing time of 72 hr at 27°C</td>
</tr>
<tr>
<td><strong>Broad BSD</strong></td>
</tr>
<tr>
<td>Density (g/cm³)</td>
</tr>
<tr>
<td>Compressive Strength (MPa)</td>
</tr>
<tr>
<td>Permeability (mD)</td>
</tr>
<tr>
<td>Compressive Strength (MPa)</td>
</tr>
<tr>
<td>Permeability (mD)</td>
</tr>
<tr>
<td>1.77 20.8 0.050 – –</td>
</tr>
<tr>
<td>1.46 14.0 0.0076 8.2 1.25</td>
</tr>
<tr>
<td>1.22 9.4 0.017 6.8 5.7</td>
</tr>
<tr>
<td>1.08 7.4 0.054 5.7 25.7</td>
</tr>
<tr>
<td>0.90 4.7 89 3.2 1.99</td>
</tr>
<tr>
<td>0.61 1.5 58,890 1.6 6,800</td>
</tr>
<tr>
<td><strong>Narrow BSD</strong></td>
</tr>
<tr>
<td>1.80 33.9 0.025 – –</td>
</tr>
<tr>
<td>1.45 13.6 0.039 10.2 3</td>
</tr>
<tr>
<td>1.27 10.0 0.160 6.9 14.5</td>
</tr>
<tr>
<td>1.12 6.3 44 5.3 173</td>
</tr>
<tr>
<td>0.86 3.2 12,022 2.8 676</td>
</tr>
<tr>
<td>0.61 2.7 5,321 1.9 3,730</td>
</tr>
<tr>
<td>Class G Base Slurry</td>
</tr>
<tr>
<td>Curing time of 72 hr at 27°C</td>
</tr>
<tr>
<td><strong>Broad BSD</strong></td>
</tr>
<tr>
<td><strong>Narrow BSD</strong></td>
</tr>
<tr>
<td>1.80 33.9 0.025 – –</td>
</tr>
<tr>
<td>1.45 13.6 0.039 10.2 3</td>
</tr>
<tr>
<td>1.27 10.0 0.160 6.9 14.5</td>
</tr>
<tr>
<td>1.12 6.3 44 5.3 173</td>
</tr>
<tr>
<td>0.86 3.2 12,022 2.8 676</td>
</tr>
<tr>
<td>0.61 2.7 5,321 1.9 3,730</td>
</tr>
<tr>
<td>† From de Rozières and Ferrière, 1991. Reprinted with permission of SPE.</td>
</tr>
<tr>
<td>‡ Bubble-size distribution</td>
</tr>
</tbody>
</table>

---

![Fig. 7-22. Schematic diagram of foamed cement generator (from de Rozières and Ferrière, 1991). Reprinted with permission of SPE.](image)

![Fig. 7-23. Schematic diagram of test cell to cure foamed cements (from de Rozières and Ferrière, 1991). Reprinted with permission of SPE.](image)
size distribution is less clear. At densities above about 1.0 g/cm³, foams with broad bubble-size distributions have lower permeabilities. At densities below about 1.0 g/cm³, foams with a narrow bubble-size distribution have lower permeabilities.

Chekiri (1978) reported that perforation of foamed cements with qualities above 40% tends to cause excessive fracturing. As a rule, the permeability also increases dramatically when the quality exceeds 40%; however, this depends on the additives, type of foamer, and curing conditions (Aldrich and Mitchell, 1975; Smith et al., 1984).

**Mechanical properties**

Foamed cement has a lower Young's modulus than conventional cements (Deeg et al., 1999). To achieve a lower Young's modulus with conventional cements, one must add large amounts of water, resulting in lower compressive strength. With foamed cement, the impact on compressive strength is lower. Cements with lower Young's moduli are less susceptible to failure when exposed to the common mechanical stresses associated with well operations. A detailed discussion of the mechanical properties of well cements is presented in Chapter 8.

**Shear bond**

Davies et al. (1981) reported that foamed cement can undergo a bulk expansion before setting. In some situations, this can result in improved bonding (Slaton, 1981). This hypothesis is supported by indirect evidence from the improved bond logs obtained from wells cemented with foamed cement and can be explained as an effect of pressure maintenance by the compressed gas in the cement. As the cement loses hydrostatic pressure during gelation, the gas pressure maintains tight contact between the cement and the casing or formation.

Smith et al. (1984) reported that foamed cement at 7.9 lbm/gal [948 kg/m³] develops higher shear-bond strength than a 12% bentonite cement at 12.7 lbm/gal [1,520 kg/m³]. They also found that the ratio of shear bond to compressive strength is higher for foamed cements and increases with nitrogen concentration. These data are presented in Table 7-19.

**Thickening time**

Among the tests performed on foamed cement, thickening time is the most difficult to perform and the least conclusive. To be valid, this test should be performed under simulated downhole conditions, and the foam should be mixed in a manner comparable to what occurs on location. Thus, ideally, the slurry should be prepared in a pressurized mixer and transferred under pressure to the pressurized consistometer. The thickening time test involves measuring the evolution of slurry viscosity (Appendix B). Because of the particular rheological behavior of foam, the shear field in the consistometer is not uniform. A large part of the foam remains static, while the small amount that is sheared is destabilized.

Calorimetry experiments performed under static conditions at atmospheric pressure showed that the foam quality does not influence the hydration kinetics (de Rozières and Ferrière, 1991) (Fig. 7-24). A calorimetric thermogram is not equivalent to the thickening time. These results only demonstrate that the cement hydration process is not affected by the presence of gas in the system.

Instead of testing foamed systems, a common procedure is to measure the thickening time of the base slurry containing the additives, surfactants, and stabilizers. This method gives a reasonable estimate of the working time for the foamed slurry (Davies et al., 1981; McElfresh and Boncan, 1982).

**Fluid loss**

Introducing a gas to a liquid medium significantly reduces the rate at which the liquid will flow through porous media (Anderson, 1975). De Rozières and Ferrière (1991) evaluated foamed cements, with and without fluid-loss additives, and found that the fluid-loss rates were lower when gas was present (Fig. 7-25).

| Table 7-19. Compressive Strength and Shear-Bond Strength of Conventional and Foamed Cements†, ‡ |
|---------------------------------|----------------|----------------|----------------|----------------|
| Composition                     | Density (lbm/gal [g/cm³]) | Compressive Strength (psi [MPa]) | Shear Bond Strength (psi [MPa]) | Ratio of Shear to Compressive Strength (%) |
| Class G                         | 15.8 [1.90]               | 4,200 [29.0]               | 403 [2.8]               | 9.6 |
| Class G + 12% bentonite         | 12.7 [1.53]               | 772 [5.0]                  | 70 [0.5]                | 9.5 |
| 40% gas                         | 9.5 [1.14]                | 873 [6.0]                  | 118 [0.8]               | 13.5 |
| 50% gas                         | 7.9 [0.95]                | 571 [3.9]                  | 97 [0.7]                | 17.1 |

† From Smith et al. (1984). Reprinted with permission of World Oil.

‡ Cured 24 hr at 80°F (27°C), then 24 hr at 170°F (80°C)
Thermal and electrical conductivity

Short et al. (1961) reported that foams have lower thermal conductivity, because of the presence of gas voids and the lower amount of solids. Nelson (1986) reported that the thermal conductivity of cement systems is roughly proportional to slurry density, regardless of whether the cement was foamed. These data are presented in Fig. 7-26.

Studies of the resistivity of foamed cement indicate that the electrical conductivity is similar to that of conventional cements (Smith et al., 1984) (Table 7-20).

Table 7-20. Resistivity of Foamed and Conventional Cements†

<table>
<thead>
<tr>
<th>Cement type</th>
<th>Density (lbm/gal [g/cm³])</th>
<th>Specific Resistivity‡ (ohm-cm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional</td>
<td>15.7 [1.88]</td>
<td>$1.25 \times 10^4$</td>
</tr>
<tr>
<td>Foamed</td>
<td>9.3 [1.11]</td>
<td>$1.4 \times 10^4$</td>
</tr>
</tbody>
</table>

† From Smith et al. (1984). Reprinted with permission from World Oil.
‡ ASTM D-257

Fig. 7-24. Effect of foam quality on setting kinetics of foamed cements (from de Rozières and Ferrière, 1991). Reprinted with permission of SPE.

Fig. 7-25. Effect of foam quality on fluid-loss behavior of foamed cements (from de Rozières and Ferrière, 1991). Reprinted with permission of SPE.

Fig. 7-26. Cement density/thermal conductivity relationship (from de Rozières and Ferrière, 1991). Reprinted with permission of SPE.
Rheology

The rheological behavior of foams is unlike that of other fluids (Chapter 4). The differences arise from many factors. Foams are compressible fluids; they are heterogeneous and have variable properties under shear. Foams are dynamically unstable, shear-history-dependent fluids in which the bubble structure is continuously destroyed and rebuilt. For these reasons, rotational viscometers with a fixed amount of sample are unsuitable (Heller and Kuntamukkula, 1987). The rotational shear disturbs the bubble network, often resulting in foam collapse.

Continuous flow-tube viscometers are more suitable for testing foams, despite the fact that foams are compressible, are non-Newtonian, and will never attain a steady state (Reidenbach et al., 1986; Harris and Reidenbach, 1987; Mueller et al., 1990). Viscosity, density, and flow rate will vary continuously as the system pressure changes along the tube. As a result, the equations to calculate shear stress and shear rate at the wall require corrections (Harris and Reidenbach, 1987). In addition, low-pressure viscosity measurements of foamed cements may not be representative of field conditions. Such problems are minimized if tests are performed at the pressures encountered in the well and at low differential pressure.

While studying foamed fracturing fluids, Harris and Reidenbach (1987) found that the bubbles tend to reach a small, uniform size at high energy levels. At low energy levels, the bubbles coalesce and drain, forming large nonuniform bubbles. Harris and Reidenbach also observed that the frictional pressure drop for foamed fluids can increase twofold from the time a foam is created until equilibrium is reached.

To the best of the authors' knowledge, no routine rheological measurement is made on foamed cement slurries. However, visual observations of foamed cements flowing in plastic tubes have shown that, at low flow rates, the foams flow as a rigid plug, moving on a thin film of water next to the wall (Princen, 1982).

7-11 Flexible cements

As discussed in Chapter 8, the mechanical properties of well cements have become a topic of considerable interest. Today, in addition to the traditional unconfined-compressive-strength measurement, tensile strength, Young's modulus, and Poisson's ratio are frequently considered during the cement-design process. The methods employed to measure these parameters are discussed in detail in Appendix B.

During the life of a well, the set cement can fail because of shear and compressional stresses. There are several stress conditions associated with cement-sheath failures. One such condition is the result of relatively high fluid pressures and temperatures inside the casing during testing, perforating, hydraulic fracturing, or fluid production (Bosma et al., 2000). Another stress condition results from exceedingly high pressures that occur inside the cement sheath because of thermal expansion of the interstitial fluid. A third condition involves tectonic movement of the formation. When such stresses are exerted on set cement in the wellbore, the set cement can fail in the form of radial circumferential cracking of the cement matrix or by a breakdown of the cement/casing or cement/formation bonds. Such failures compromise zonal isolation and can lead to severe well problems. Thus, the well cementing industry has recognized the need for highly resilient and flexible well-cement compositions that can withstand the stresses outlined above.

As explained in Chapter 8, a detailed analysis of the mechanisms leading to failure of the cement sheath showed that the risk of rupture is directly linked to the tensile strength of the set cement and is attenuated when the ratio of tensile strength to Young's modulus is increased. Young's modulus characterizes the flexibility of a material. Thus, to increase the tensile strength to Young's modulus ratio, the set cement should have a low Young's modulus (Thiercelin et al., 1997).

7-11.1 Slurry density reduction

Conventional slurry density reduction, using extenders that accommodate additional water (e.g., sodium silicate and bentonite), increases the flexibility of the set cement (Table 7-21). Although the flexibility is increased, the effects on compressive strength and permeability are detrimental.

7-11.2 Flexible particles

Another possibility to modify the elasticity of the set cement is to incorporate flexible particles in the slurry design. In the construction industry, incorporating ground particles from rubber tires in concrete improves toughness, durability, and resilience (Eldin et al., 1993). The rubber aggregates are used in highway construction for antishock properties, as a sound-absorbing material in antinoise walls, and in earthquake-resistant buildings.

Adding ground rubber particles to well cements has been practiced for more than 30 years as a method to improve resistance to shocks during perforating (F.E. Hook, unpublished data, 1971). More recently, improvements have been made with optimized rubber-particle-size distributions. Karimov et al. (1985) proposed using particles in the 4/20 mesh range to improve impact and bending strength. Brothers and de Blanc (1998) proposed adding ground-rubber-tire particles in the 10/20 mesh to 20/30 mesh size range. The set cements...
exhibit improved elasticity, ductility, and expansion properties over a wide density range—14.3 to 19.0 lbm/gal [1,720 to 2,280 kg/m$^3$]. Le Roy-Delage et al. (2000) described cement systems containing from 30% to 100% BWOC rubber particles in the 40/60 mesh range. As shown in Table 7-22, the resulting set cements are more flexible.

EPS cement systems (Section 7-9) have been formulated using flexible particles as one of the components (Le Roy-Delage et al., 2000). The particles have the following characteristics:

- Particle size: ≤500 μm
- Young's modulus: <5,000 MPa, preferably <2,000 MPa
- Poisson's ratio: >0.3.

Thermoplastics, like polyamide, polypropylene, and polyethylene, or polymers, like styrene divinylbenzene or styrene butadiene, are compatible with these performance criteria. Because the specific gravities of these materials fall between 0.9 and 1.2, they can also reduce the cement system density. Table 7-23 presents mechanical-properties data from set cements containing various amounts of flexible particles.

### Table 7-21. Mechanical Properties of Conventionally Extended Set Cements

<table>
<thead>
<tr>
<th>Slurry Density (lbm/gal [kg/m$^3$])</th>
<th>Tensile Strength, TS (psi [MPa])</th>
<th>Young’s Modulus, $E$ (psi [MPa])</th>
<th>$TS/E \times 1,000$</th>
<th>Compressive Strength (psi [MPa])</th>
<th>Water Permeability, $k$ (mD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>15.8 [1,897]</td>
<td>605 [4.23]</td>
<td>944,000 [6,600]</td>
<td>0.64</td>
<td>51,230 [36.6]</td>
<td>0.001</td>
</tr>
<tr>
<td>14.0 [1,680]</td>
<td>479 [3.35]</td>
<td>538,000 [3,759]</td>
<td>0.90</td>
<td>3,270 [22.9]</td>
<td>0.008</td>
</tr>
<tr>
<td>12.0 [1,440]</td>
<td>86 [0.60]</td>
<td>72,100 [504]</td>
<td>1.19</td>
<td>450 [3.21]</td>
<td>0.138</td>
</tr>
</tbody>
</table>

† After Le Roy-Delage et al. (2000). Reprinted with permission of SPE.

### Table 7-22. Mechanical Properties of Set Cements Containing Rubber Particles

<table>
<thead>
<tr>
<th>Slurry Density (lbm/gal [kg/m$^3$])</th>
<th>Tensile Strength, TS (psi [MPa])</th>
<th>Young’s Modulus, $E$ (psi [MPa])</th>
<th>$TS/E \times 1,000$</th>
<th>Compressive Strength (psi [MPa])</th>
</tr>
</thead>
<tbody>
<tr>
<td>12.0 [1,440]</td>
<td>93 [0.65]</td>
<td>73,900 [516.7]</td>
<td>1.26</td>
<td>412 [2.88]</td>
</tr>
<tr>
<td>13.1 [1,570]</td>
<td>140 [0.99]</td>
<td>137,800 [963.6]</td>
<td>1.04</td>
<td>819 [5.73]</td>
</tr>
<tr>
<td>13.6 [1,630]</td>
<td>207 [1.45]</td>
<td>189,000 [1,320]</td>
<td>1.11</td>
<td>1,130 [7.93]</td>
</tr>
<tr>
<td>14.1 [1,690]</td>
<td>237 [1.66]</td>
<td>240,000 [1,678]</td>
<td>1.01</td>
<td>1,782 [12.46]</td>
</tr>
<tr>
<td>15.2 [1,820]</td>
<td>390 [2.73]</td>
<td>460,900 [3,223]</td>
<td>0.86</td>
<td>2,890 [20.21]</td>
</tr>
<tr>
<td>16.4 [1,970]</td>
<td>323 [2.26]</td>
<td>864,000 [6,042]</td>
<td>0.76</td>
<td>3,934 [27.51]</td>
</tr>
</tbody>
</table>

† After Le Roy-Delage et al. (2000). Reprinted with permission of SPE.

### Table 7-23. Mechanical Properties of EPS Set Cements Containing Flexible Particles

<table>
<thead>
<tr>
<th>Flexible Particle (volume %)</th>
<th>Slurry Density (lbm/gal [kg/m$^3$])</th>
<th>Tensile Strength, TS (psi [MPa])</th>
<th>Young’s Modulus, $E$ (psi [MPa])</th>
<th>$TS/E \times 1,000$</th>
<th>Compressive Strength, CS (psi [MPa])</th>
</tr>
</thead>
<tbody>
<tr>
<td>Styrene divinylbenzene (25)</td>
<td>14.0 [1,680]</td>
<td>365 [2.52]</td>
<td>521,400 [3,595]</td>
<td>0.72</td>
<td>4,860 [33.5]</td>
</tr>
<tr>
<td>Styrene divinylbenzene (30)</td>
<td>12.1 [1,450]</td>
<td>160 [1.10]</td>
<td>194,200 [1,339]</td>
<td>0.84</td>
<td>1,930 [13.3]</td>
</tr>
<tr>
<td>Polypropylene (24)</td>
<td>13.7 [1,640]</td>
<td>381 [2.63]</td>
<td>438,000 [3,020]</td>
<td>0.88</td>
<td>3,810 [26.3]</td>
</tr>
</tbody>
</table>

† After Le Roy-Delage et al. (2000). Reprinted with permission of SPE.
7-11.3 Elastomeric composites

Onan et al. (1993) described a composite material based on styrene-butadiene rubber latex. Various fillers, such as carbon black, calcium carbonate, silica, and quick-setting Portland cement can be added to adjust the mechanical properties of the composite. This system has been used to cement CO2-injection wells and multilateral junctions (Xenaxis et al., 1997). Typical mechanical performance data are shown in Table 7-24.

7-11.4 Fibers

Adding fibers or ribbons to a cement matrix also improves flexural strength. Nylon fibers have been used for many years for this purpose (Chapter 3). More recently, Le Roy-Delage et al. (2000) and Baret et al. (2002) described the addition of metallic microribbons to improve impact resistance, toughness, and tensile strength. The principal applications of this system are kickoff plugs and multilateral junctions.

The performance of the metallic ribbon system is illustrated in Fig. 7-27, which shows a load-deflection curve recorded during a flexural test. The plot shows the amount of force required to bend or deflect the cement sample a given distance. The results show that a neat slurry fails completely after being deflected less than 0.1 mm. The microribbon slurry was able to bear a load after a deflection of nearly 1 mm.

![Fig. 7-27. Typical load-deflection curve comparing neat and microribbon cement systems.](image)

### Table 7-24. Mechanical Properties of Elastomeric Composite Systems†

<table>
<thead>
<tr>
<th>Elastomeric Composite (%)</th>
<th>Slurry Density (lbm/gal)</th>
<th>Tensile Strength, TS (psi)</th>
<th>Young’s Modulus, E (psi)</th>
<th>TS/E (&lt;1,000)</th>
<th>Compressive Strength, CS (MPa)</th>
<th>Air Permeability, k (mD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Neat</td>
<td>15.7</td>
<td>200</td>
<td>700</td>
<td>0.28</td>
<td>–</td>
<td>0.383</td>
</tr>
<tr>
<td>67% thermatomic carbon</td>
<td>14.0</td>
<td>720</td>
<td>4,100</td>
<td>0.18</td>
<td>–</td>
<td>0.014</td>
</tr>
<tr>
<td>80% CaCO₃</td>
<td>12.0</td>
<td>910</td>
<td>5,200</td>
<td>0.18</td>
<td>–</td>
<td>0.029</td>
</tr>
<tr>
<td>130% CaCO₃</td>
<td>14.0</td>
<td>1,080</td>
<td>10,000</td>
<td>0.11</td>
<td>–</td>
<td>0.007</td>
</tr>
<tr>
<td>300% silica</td>
<td>12.1</td>
<td>110</td>
<td>5,300</td>
<td>0.02</td>
<td>105</td>
<td>0.012</td>
</tr>
<tr>
<td>150% silica flour, 25% quick-setting cement</td>
<td>14.0</td>
<td>210</td>
<td>8,200</td>
<td>0.03</td>
<td>245</td>
<td>0.001</td>
</tr>
<tr>
<td>67% quick-setting cement</td>
<td>14.6</td>
<td>180</td>
<td>9,100</td>
<td>0.02</td>
<td>505</td>
<td>–</td>
</tr>
<tr>
<td>77% quick-setting cement</td>
<td>14.0</td>
<td>470</td>
<td>23,000</td>
<td>0.02</td>
<td>985</td>
<td>–</td>
</tr>
<tr>
<td>113% quick-setting cement</td>
<td>14.0</td>
<td>215</td>
<td>200,000</td>
<td>&lt;0.01</td>
<td>732</td>
<td>–</td>
</tr>
<tr>
<td>150% Class A cement</td>
<td>14.7</td>
<td>150</td>
<td>25,000</td>
<td>0.01</td>
<td>795</td>
<td>–</td>
</tr>
</tbody>
</table>

† After Onan et al. (1993). Reprinted with permission of SPE.
‡ Not measured
7-12 Microfine cements

Microfine cements are composed of very small particles (generally 4 to 15 μm). Therefore, the surface area is very large (500 to greater than 1,000 m²/kg). The most common microfine cements are very fine Portland cements (Ewert et al., 1991; Bensted and Barnes, 2002); however, slag cements may also be incorporated (Clarke and McNally, 1993; Section 7-8). The advantage of such cements is their improved ability to penetrate and flow through tight spaces and porous media. The Portland cement–based microfine cements generally behave similarly to their conventional counterparts; however, owing to their higher reactivity, additional gypsum or retarders may be necessary to achieve predictable rheological performance and setting.

The principal uses for microfine cements include the following.

- Squeeze cementing (Heathman and East, 1992) (Chapter 14; Section 7-8.2.1)
- Sealing casing leaks (Meek and Harris, 1991; Lizak et al., 1992) (Chapter 14)
- Cementing permafrost zones (Section 7-4)
- Cementing shallow strings in deepwater wells

More detailed discussions of the applications of microfine cements are found in the sections indicated above.

7-13 Acid-soluble cements

As discussed in Chapter 6, lost circulation during drilling and cementing is a common problem. Most common remedies, such as lost-circulation materials (e.g., flakes and fibers) and thixotropic cements, remain in the thief zone permanently. This is not a problem unless the thief zone is also the producing zone. Such situations include gas-injection and gas-storage wells. Therefore, there is a need for lost circulation materials that can easily be removed after well construction is complete.

Such a temporary system, based on magnesium oxychloride (or Sorel) cement, was developed by Sweatman and Scoggins (1990) and Vinson et al. (1992). Magnesium oxychloride is made by mixing powdered magnesium oxide with a concentrated solution of magnesium chloride. The principal binder phases are Mg(OH)₂Cl • 4H₂O and Mg(OH)₃Cl • 4H₂O. The set-cement is very strong; however, it readily dissolves when exposed to acid.

A modified Sorel cement for oilfield applications consists of magnesium and calcium oxides, carbonates, and sulfates. When added to seawater or a chloride brine, magnesium oxychloride hydrates form. The thickening behavior can be modified by common retarders such as borax (Fig. 7-28) and accelerators such as calcium chloride (Bensted and Barnes, 2002); therefore, such cements can be pumped similarly to conventional well cements. Once placed, the set cement can be readily removed by acidizing with HCl.

In addition to solving lost circulation problems, acid-soluble cements have been used as diverters to provide temporary zonal isolation and as kickoff plugs in weak formations (Chapter 14).

7-14 Chemically bonded phosphate ceramics

Chemically bonded phosphate ceramics (CBPCs) are binders that fall between sintered ceramics (e.g., pottery, porcelain) and chemically bonded systems (e.g., Portland cement). CBPCs are formed by acid-base reactions between an acid phosphate (e.g., Mg, Ca, or Al) and a metal oxide (e.g., MgO, CaO, or ZnO₂) (Jeong and Wagh, 2003).

Calcium aluminate–based CBPCs are being used as cements for geothermal wells (Chapter 10). Magnesium potassium phosphates, originally developed to stabilize and encapsulate radioactive and hazardous waste streams, have also found use as fast-setting well cements (Wagh and Brown, 1999). The cement is prepared by calcining MgO at 2,372°F [1,300°C]. The calcined MgO is then reacted with a KH₂PO₄ solution to form the binder.

\[
\text{MgO + KH}_2\text{PO}_4 + 5\text{H}_2\text{O} \rightarrow \text{MgKPO}_4 + 6\text{H}_2\text{O} 
\] (7-20)
When the MgO is added to the KH$_2$PO$_4$ solution, the resulting paste sets within 1 hr at ambient temperature. The system can be retarded by adding boric acid. The boric acid reacts with the acid phosphate and forms a temporary coating of magnesium boron phosphate on the surface of the MgO particles. Typical performance of a system containing boric acid retarder is shown in Fig. 7-29.

The performance is notable in that the ultimate compressive strength is much higher than that of set Portland cement.

### 7-15 Storable cement slurries

As described in Chapter 11, cement-slurry mixing in the well cementing industry essentially consists of combining fine cement powder with mix water. The process involves cutting sacks of cement or transferring bulk cement pneumatically to the mixing unit. Many parameters must be controlled at the mixing unit, including slurry density, mixing energy, and mixing time. Density is arguably the most difficult parameter to control. Key cement-slurry properties such as thickening time, rheology, free water, and compressive strength depend upon density.

A cementing operation can be simplified by eliminating the handling of dry powders. This concept was realized by Rae and Johnston (1995), who introduced liquid cement premixes that can be stored in the liquid state almost indefinitely and activated at the wellsite during the cement job. This technique can lead to improvements in job efficiency and service quality in both primary and remedial cementing operations (Rae and Johnston, 1996a and 1996b).

The storable slurries can be made from Portland cement, slag cement, or other blended cements, and can also contain other cement additives. Water is the carrier fluid. A set retarder, such as a hydroxycarboxylic acid, is necessary to prevent the setting of the slurry during storage. To prevent settling of the cement solids during storage, suspending agents such as polymers and clays are added. At the wellsite, the storable slurry is pumped to the cement mixer, where an activator is added to counteract the retarder and reinitiate cement hydration. The preferred activator is sodium silicate.

### 7-16 Summary

Table 7-25 summarizes the cement systems presented in this chapter, indicating their principal uses, chemical compositions, and mechanisms of action.

![Fig. 7-29. Setting characteristics of a magnesium potassium phosphate cement system (Wagh and Brown, 1999).](image-url)
## Table 7-25. Cement System Summary

<table>
<thead>
<tr>
<th>Cement System</th>
<th>Principal Uses</th>
<th>Chemical Compositions</th>
<th>Mechanisms of Action</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Thixotropic cements</strong></td>
<td>Lost circulation prevention</td>
<td>Portland cements containing one of the following additives</td>
<td>Increased gel strength</td>
</tr>
<tr>
<td></td>
<td>Slurry fallback prevention</td>
<td>Bentonite</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Gas migration prevention</td>
<td>Calcium sulfate hemihydrate, Aluminum sulfate/iron sulfate</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Crosslinked cellulose polymer</td>
<td></td>
</tr>
<tr>
<td><strong>Expansive cements</strong></td>
<td>Improved cement/casing and cement/formation bond</td>
<td>Commercial expanding cements or Portland cement containing calcium sulfate hemihydrate</td>
<td>Formation of ettringite crystals</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Salt cements</td>
<td>Internal pressure exerted by crystallization of salt in pores</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Portland cement containing aluminum powder</td>
<td>Generation of hydrogen gas in situ</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Portland cement containing calcined magnesium oxide</td>
<td>Conversion of MgO (periclase) to Mg(OH)₂ (brucite)</td>
</tr>
<tr>
<td><strong>Freeze-protected cements</strong></td>
<td>Cementing across permafrost zones</td>
<td>Calcium aluminate cement</td>
<td>Rapid strength development at low temperatures</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Gypsum-Portland cement blends</td>
<td>Rapid strength development at low temperatures; lower heat of hydration than calcium aluminate</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Ultraline Portland cement</td>
<td>High surface area increases hydration rate</td>
</tr>
<tr>
<td><strong>Salt cement systems</strong></td>
<td>Cementing across salt zones or sensitive formations</td>
<td>Portland cements containing sodium chloride or potassium chloride at concentrations up to saturation</td>
<td>Systems do not disturb salt-bearing formations</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Systems do not disturb sensitive clays</td>
<td></td>
</tr>
<tr>
<td><strong>Latex-modified cement systems</strong></td>
<td>Improved cement/casing and cement/formation bond</td>
<td>Portland cements containing one of the following latexes</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Improved fluid-loss control</td>
<td>Polyvinylidene chloride</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Gas migration prevention</td>
<td>Polyvinyl acetate</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Styrene-butadiene copolymer</td>
<td></td>
</tr>
<tr>
<td><strong>Cements for corrosive environments</strong></td>
<td>Cementing chemical waste disposal wells</td>
<td>Epoxy-based cement systems, Elastomeric composites</td>
<td>Chemically inert to strong acids and bases</td>
</tr>
<tr>
<td></td>
<td>Cementing CO₂ injection wells</td>
<td>Pozzolanic cement systems, BFS systems</td>
<td>Reduced cement-matrix permeability, improved chemical resistance</td>
</tr>
<tr>
<td><strong>BFS systems</strong></td>
<td>Alternative to or supplement for Portland cement</td>
<td>BFS + activator (e.g., sodium hydroxide or Portland cement)</td>
<td>Formation of C-S-H phase, with extensive incorporation of Al, Mg, Fe, and sulfate in structure</td>
</tr>
<tr>
<td></td>
<td>Conversion of drilling fluid to cement</td>
<td>BFS + activator mixed with drilling fluid</td>
<td></td>
</tr>
<tr>
<td><strong>EPS cement systems</strong></td>
<td>Systems with improved placement and set-cement properties over a wide slurry-density range</td>
<td>Cement blends with multimodal particle-size distributions</td>
<td>Particle-size distribution minimizes mix-water concentration required to prepare pumpable slurry; set cement is less permeable than conventional systems</td>
</tr>
<tr>
<td><strong>Ultralow-density cement systems</strong></td>
<td>Cementing across formations with low fracture gradients or that are vuggy or cavernous</td>
<td>Cements containing glass or ceramic microspheres, Foamed cements</td>
<td>Low slurry density reduces hydrostatic pressure in wellbore and prevents formation breakdown</td>
</tr>
<tr>
<td><strong>Flexible cement systems</strong></td>
<td>Improved resistance to stresses induced by perforating, hydraulic fracturing, and tectonic movement</td>
<td>Cements containing flexible particles</td>
<td>Flexible particles decrease Young's modulus and increase Poisson's ratio</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Cements containing nylon or metallic fibers</td>
<td>Fibers act as reinforcement and improve flexural strength and toughness</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Elastomeric composites</td>
<td>Polymer matrix filler is flexible</td>
</tr>
<tr>
<td><strong>Microfine cement systems</strong></td>
<td>Squeeze cementing, sealing casing leaks</td>
<td>Portland or BFS cements with small particle size (4 to 15 μm) and high surface area (500 to 1,000 m²/kg)</td>
<td>Smaller particles more readily enter cracks and formation pores</td>
</tr>
<tr>
<td><strong>Acid-soluble cement systems</strong></td>
<td>Temporary solution for lost circulation</td>
<td>Magnesium oxychloride (Sorel) cements</td>
<td>Principal binder phase is readily removed by contact with a strong acid (e.g., HCl)</td>
</tr>
<tr>
<td><strong>Chemically bonded phosphate ceramics</strong></td>
<td>Fast-setting cements that develop high compressive strength</td>
<td>Magnesium potassium phosphate</td>
<td>Acid-base reaction between an acid phosphate and a metal oxide</td>
</tr>
<tr>
<td><strong>Storable cement slurries</strong></td>
<td>Eliminates handling of dry powders during cementing operations</td>
<td>Portland, BFS or blended cements slurried in aqueous solution containing a strong cement retarder</td>
<td>During cement job, concentrated slurry is diluted with mix water containing activator (e.g., sodium silicate)</td>
</tr>
</tbody>
</table>
## 7-17 Acronym list

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>API</td>
<td>American Petroleum Institute</td>
</tr>
<tr>
<td>BFS</td>
<td>Blast-furnace slag</td>
</tr>
<tr>
<td>BHCT</td>
<td>Bottomhole circulating temperature</td>
</tr>
<tr>
<td>BHST</td>
<td>Bottomhole static temperature</td>
</tr>
<tr>
<td>BWOW</td>
<td>By weight of water</td>
</tr>
<tr>
<td>CBPC</td>
<td>Chemically bonded phosphate ceramics</td>
</tr>
<tr>
<td>CS</td>
<td>Compressive strength</td>
</tr>
<tr>
<td>EPS</td>
<td>Engineered particle size</td>
</tr>
<tr>
<td>ISO</td>
<td>International Organization for Standardization</td>
</tr>
<tr>
<td>PVF</td>
<td>Packing volume fraction</td>
</tr>
<tr>
<td>SG</td>
<td>Specific gravity</td>
</tr>
<tr>
<td>SVF</td>
<td>Solid volume fraction</td>
</tr>
<tr>
<td>TS</td>
<td>Tensile strength</td>
</tr>
</tbody>
</table>
8-1 Introduction

Until recently, the well cementing industry focused on one principal mechanical property of set cement—unconfined uniaxial compressive strength—to qualify a cement design. The uniaxial compressive strength is determined by a cube-crushing test (Appendix B) and is used to estimate the ability of set cement to support casing and survive the perforation process. When combined with water- or air-permeability measurements (Appendix B), one can also estimate the cement’s ability to provide zonal isolation and resist attack from formation fluids.

Indirect ultrasonic techniques using tools like the ultrasonic cement analyzer (UCA) (Appendix B) allow one to monitor the evolution of strength with time. With the UCA, one can determine the curing time required for a cement system to attain a given compressive strength.

In recent years, the well cementing industry has begun to concentrate on set cements’ ability to provide zonal isolation throughout the lifetime of the well. This was triggered by the observation that, even in situations in which the cement was properly placed and provided a good initial hydraulic seal, zonal isolation disappeared with time (Goodwin and Crook, 1992; Jackson and Murphey, 1993). Zonal isolation loss has been attributed to several causes.

- Gas-migration problems that were not initially detected
- Loss of cement-bond log response with time
- Fracturing the wrong zone during a stimulation treatment
- Extreme downhole temperature or pressure changes
- Chemical attack
- Pressure migration to shallower zones

Laboratory and modeling studies have shown that the principal cause of cement-sheath damage is the stresses induced by varying downhole conditions (Parcevaux and Sault, 1984; Jutten et al., 1989; Goodwin and Crook, 1992; Jackson and Murphey, 1993; Bol et al., 1997; Thiercelin et al., 1997; Bosma et al., 1999). The stresses arise from not only the wellbore pressure or the rock far-field stress, but also from any change of downhole temperature or pore pressure. Cement tensile strength, elasticity, and ductility are mechanical parameters that may be more important to long-term durability than an arbitrary measure of cube compressive strength (Thiercelin et al., 1997; Bosma et al., 1999; di Lullo and Rae, 2000; Ravi et al., 2002).

Knowledge of the appropriate cement mechanical properties allows one to characterize the cement deformation under applied downhole stresses and to predict whether the cement will be able to survive the stresses. In this chapter, basic rock-mechanics concepts are presented in the context of well cements, followed by a discussion of how these concepts can be applied to design cement systems that are appropriate for the anticipated downhole environment.

8-2 Basic concepts

The basic concepts of stress and strain are presented in this section. These concepts have been presented previously in the context of rock mechanics analysis (Thiercelin and Roegiers, 2000). For further details, the reader is referred to the classical works by Love (1927), Timoshenko and Goodier (1970), and Muskhelishvili (1977).

Stress and strain have distinct meanings to the engineer. For example, a normal stress, \( \sigma \), can be viewed as a normal force (to a surface) per unit area while linear strain, \( \varepsilon \), is the resulting deformation.

8-2.1 Stress

Consider a randomly oriented plane of area \( \Delta A \), centered on a Point \( P \) within a body. When a resultant force \( \Delta F \) acts on the body (Fig. 8-1), the stress vector \( \sigma \) at that point is defined as

\[
\sigma = \lim_{\Delta A \to 0} \left( \frac{\Delta F}{\Delta A} \right).
\]

Therefore, this quantity is expressed as a force per unit area. In classical solid mechanics, the tensile stress is taken to be positive by convention. However, in rock
mechanics, compressive stress is taken to be positive because geologic forces are usually compressive in nature. Because either convention can be used for mechanical studies of well cements, it is important to clearly state the convention being used. In this chapter, tensile stresses are taken to be positive.

The resultant stress, $\sigma$, can be decomposed into a normal component ($\sigma_n$) and a shear component ($\tau$). The shear component tends to "shear" the material in the plane $\Delta A$. The normal component of stress acts perpendicular to $\Delta A$, and the shear component acts in the plane of $\Delta A$.

An infinite number of planes can be drawn through a given point, varying the values of $\sigma_n$ and $\tau$. The stress condition, therefore, depends on the inclination of the plane. Consequently, for a complete description of a stress, one must not only specify its magnitude and direction, but also the direction of the surface upon which it acts.

In a two-dimensional situation, if $\sigma_x$, $\sigma_y$, and $\tau_{xy}$ are known (Fig. 8-2), the stress state on any plane oriented at an angle $\theta$ from $\sigma_x$ can be expressed as follows:

$$\sigma_n = (\sigma_x \cos^2 \theta) - (2\tau_{xy} \sin \theta) + (\sigma_y \sin^2 \theta) \quad (8-2)$$

and

$$\tau = \frac{1}{2}(\sigma_y - \sigma_x) \sin 2\theta + (\tau_{xy} \cos 2\theta). \quad (8-3)$$

These expressions are obtained by writing equilibrium equations of forces along the $\sigma_n$ and $\tau$ directions, respectively (see Fig. 8-2). Note also that the moment equilibrium implies that $\tau_{xy}$ is equal to $\tau_{yx}$. There are always two perpendicular orientations of $\Delta A$ for which the shear-stress components vanish. These are called the *principal planes*. The normal stresses associated with these planes are called the *principal stresses*. In two dimensions, expressions for the principal stresses can be found by setting $\tau = 0$ in Eq. 8-3 or, because they are the minimum and maximum values of the normal stresses, by taking the derivative of Eq. 8-2 with respect to the angle $\theta$ and setting it equal to zero. In either case, one obtains the following expression for the value of $\theta$ at which the shear stress vanishes

$$\theta = \frac{1}{2} \arctan \left( \frac{2\tau_{xy}}{\sigma_y - \sigma_x} \right). \quad (8-4)$$

The two principal stress components, $\sigma_1$ and $\sigma_2$, are

$$\sigma_1 = \frac{1}{2}(\sigma_x + \sigma_y) + \left[ (\tau_{xy})^2 + \frac{1}{4}(\sigma_x - \sigma_y)^2 \right]^{1/2} \quad (8-5a)$$

and

$$\sigma_2 = \frac{1}{2}(\sigma_x + \sigma_y) - \left[ (\tau_{xy})^2 + \frac{1}{4}(\sigma_x - \sigma_y)^2 \right]^{1/2} \quad (8-5b)$$

where $\theta$ is given by Eq. 8-4.

If one generalizes this concept to three dimensions, it can be shown that six independent components of the stress (three normal and three shear components) are needed to define the stress unambiguously. The stress vector for any direction of $\Delta A$ can generally be found by writing equilibrium-of-force equations in various directions. There are three principal planes for which the shear-stress components vanish and three principal
stresses exist. Quantities that show this kind of behavior are known as second-order tensors, and the state of stress in a body is often referred to as the stress tensor.

8-2.2 Strain

When a body is subjected to a stress field, the relative positions of points within it are altered. The body deforms. If the new positions of the points do not correspond to a translation and/or a rotation (i.e., by rigid-body motion), the body is strained. This strain along an arbitrary direction can be decomposed into two components:

- an elongation, defined as

\[ \varepsilon = \lim_{L \to 0} \frac{L^e - L}{L} \]  

(8-6)

- and a shear strain, defined as

\[ \gamma = \tan(\Psi), \]  

(8-7)

where \( \Psi \) is the change of angle between the two directions that, before straining, were perpendicular (Fig. 8-3).

Consequently, strain (being either a ratio of lengths or a change of angle) is dimensionless. If one assumes that the stresses are positive in traction, a positive longitudinal strain, \( \varepsilon \), corresponds to an increase in length. Just as in the case of stresses, principal strains can be defined as longitudinal strain components acting on planes in which the shear strains have vanished.

The analogy between stress and strain analyses is not completely valid; equilibrium equations must be satisfied by the stresses and compatibility equations by the strains. These relationships place some restrictions on the local variation of stress and strain in the neighborhood of a point. For example, compatibility equations ensure that the strained body remains continuous and that no cracks or material overlaps will occur.

8-3. Cement behavior

A cement sample, like any material, deforms when subjected to stress. Determining a relationship between stress and strain is an important aspect of solid mechanics. This relationship is called the constitutive equation of the material under consideration, and various theories have been developed to describe it in a simplified way. The simplest one is the theory of elasticity, which assumes a unique relationship between stress and strain (and that the behavior is reversible). This theory is usually sufficient to analyze cement failure in tension or in compression at ambient conditions. Other theories, such as the theory of elastoplasticity, have been developed to take into account nonreversible behaviors that are observed in materials before failure. Significant nonreversible behavior is observed in cements subjected to confining pressure.

8-3.1 Stress-strain curve

Fig. 8-4 presents a typical stress-strain relationship for cement. The test is carried out under constant confining pressure and constant axial strain rate (Appendix B). The sample is protected from the confining fluid by an impermeable flexible jacket. Measurements include the axial stress, the axial strain, and the radial strain. When a confining pressure is applied to the sample, the origin of the stress-strain plots is usually translated to remove the influence of the hydrostatic loading on the stress and strain (i.e., the axial stress is actually the differential \( \sigma_a - p_{con} \), where \( \sigma_a \) is axial stress and \( p_{con} \) is the confining pressure.)

Fig. 8-4. Typical stress-strain curve during compression. The axial stress is computed from the load. The symbol \( p_{con} \) denotes the confining pressure and is maintained constant during the test. Compressive stresses are taken as positive in this figure for practicality.
During the initial stages of loading, from Points O to A, the cement becomes stiffer. This nonlinear regime is probably caused by the closing of pores, although experimental artifacts, such as the misalignment of the sample surfaces with the loading platen of the machine, could also produce such an effect.

As the load increases, the stress/strain curve becomes linear (from A to B). This is the portion of the stress-strain curve in which the behavior of the cement is nearly elastic. If unloading occurs in this region, the strain returns nearly to zero, often along a different path. When the strain follows different paths during loading and unloading, it is called hysteresis and indicates that some energy is dissipated during this cycle.

When the cement specimen is loaded beyond Point B, the yield point, the stress-strain behavior becomes nonlinear and large deformations will eventually occur. If the sample is unloaded in this region, permanent strains at zero stress are observed. The Point C is the maximum load that the cement can sustain under a given confining pressure. Cement failure (i.e., when the sample loses its integrity) occurs around this point. After this, the cement might start losing its strength because of the development of cracks. This is called the postfailure region. Some cements, especially those with high porosity and/or high elasticity, may not exhibit a maximum peak stress at high confining pressure, but will continue to carry increasing stress (i.e., continue to harden) because of compaction. Under such test conditions, these cements do not fail.

Another interesting cement characteristic is the volumetric strain, defined as the volume change divided by the original specimen volume. For the triaxial test, the volumetric strain is \( \varepsilon_v = 2 \varepsilon_r \), where \( \varepsilon_a \) is the axial strain and \( \varepsilon_r \) the radial strain. Nonelastic volumetric strain can show an increase of volume (called dilatancy when cracks are created) or a decrease in volume because of compaction.

The three important regions are therefore:
- the elastic region, in which deformation is reversible
- the plastic region, in which permanent deformation occurs
- the postfailure region, in which the cement has lost its integrity.

An important stress value is the cement strength, which is the peak strength measured during the test. These various regions and critical stresses are presented in more detail below.

### 8-3.2 Linear elasticity

To introduce the theory of linear elasticity, consider a cylindrical sample of initial length \( L \) and diameter \( d \). The sample will shorten along the loading direction when a compressive (negative) force, \( F \), is applied to its ends (Fig. 8-5). According to the definitions given in the previous section, the axial stress applied to the sample is

\[
\sigma_a = \frac{F}{A} = \frac{4F}{\pi d^2},
\]

where \( A \) is the surface area of the end of the sample. The axial strain is:

\[
\varepsilon_a = \frac{L' - L}{L},
\]

where tension is assumed to be positive. Linear elasticity assumes a linear and unique relationship between stress and strain, in which strain returns to zero when the material is unloaded. In the case of a uniaxial test, this means that:

\[
\sigma_a = E \varepsilon_a.
\]

The coefficient of proportionality, \( E \), is the Young's modulus. The higher the value of the Young's modulus, the less the sample will shorten for a given load. Some examples of Young's moduli are given in Table 8-1.

![Fig. 8-5. Sample deformation in the axial direction.](image)

### Table 8-1. Young’s Moduli of Various Materials

<table>
<thead>
<tr>
<th>Material</th>
<th>Elastic Modulus (psi [MPa])</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aluminum</td>
<td>( 10 \times 10^6 ) [70,000]</td>
</tr>
<tr>
<td>Copper</td>
<td>( 16 \times 10^6 ) [110,000]</td>
</tr>
<tr>
<td>Steel</td>
<td>( 30 \times 10^6 ) [210,000]</td>
</tr>
<tr>
<td>Window glass</td>
<td>( 10 \times 10^6 ) [70,000]</td>
</tr>
<tr>
<td>Oilwell cement</td>
<td>( 0.14–1.4 \times 10^6 ) [1,000–10,000]</td>
</tr>
<tr>
<td>Polyethylene</td>
<td>( 14–200 \times 10^3 ) [100–1,400]</td>
</tr>
<tr>
<td>Rubber</td>
<td>( 0.6–11 \times 10^3 ) [4–80]</td>
</tr>
</tbody>
</table>
When the specimen is compressed in one direction, it will not only shorten along the loading direction, but also expand in the lateral directions (Fig. 8-6). This effect is quantified by the introduction of another constant, the Poisson’s ratio, \( \nu \), defined as the ratio of the radial strain to the axial one:

\[
\nu = -\frac{\varepsilon_r}{\varepsilon_a}, \quad (8-11)
\]

with

\[
\varepsilon_r = \frac{d^* - d}{d} = \frac{r^*-r}{r}, \quad (8-12)
\]

where \( r \) is the sample radius.

These stress-strain relations can be generalized to the full three-dimensional space by

\[
\varepsilon_x = \frac{\sigma_x}{E} - \frac{\nu}{E} \left( \sigma_y + \sigma_z \right),
\]

\[
\varepsilon_y = \frac{\sigma_y}{E} - \frac{\nu}{E} \left( \sigma_x + \sigma_z \right),
\]

and

\[
\varepsilon_z = \frac{\sigma_z}{E} - \frac{\nu}{E} \left( \sigma_x + \sigma_y \right),
\]

\[
\gamma_{xy} = \frac{1}{G} \tau_{xy}; \quad \gamma_{yz} = \frac{1}{G} \tau_{yz}; \quad \gamma_{xz} = \frac{1}{G} \tau_{xz}, \quad (8-13)
\]

with the shear modulus, \( G \), given by

\[
G = \frac{E}{2(1+\nu)}. \quad (8-14)
\]

In isotropic linear elasticity, only two elastic constants are independent. For example, and as seen above, the shear modulus \( G \) can be written as a function of \( E \) and \( \nu \). Similarly, the bulk modulus, which is the coefficient of proportionality between a pressure applied to the sample and the volumetric strain, is

\[
K = \frac{E}{3(1-2\nu)}. \quad (8-15)
\]

Elasticity theory can be extended to nonlinear and anisotropic materials. A nonlinear elastic material does not have a linear relationship between stress and strain, but recovers all strain when unloaded. An anisotropic material has properties that vary in different directions.

### 8.3.3 Thermoelasticity

In a downhole environment, set cement will be subjected to temperature changes. For example, cement liberates heat during hydration, and the temperature will change as the set cement equilibrates to the surrounding formation (i.e., bottomhole circulating temperature to bottomhole static temperature).

One of the most dramatic examples is the wellbore-temperature increase that occurs during steam injection or geothermal well production, in which temperature fluctuations can exceed 350°F [194°C]. If the wellbore temperature increases, heat will diffuse by conduction through the casing then through the cement sheath and the formation rock, and the temperature will progressively increase in the wellbore region (Fig. 8-7).
Large temperature changes can affect the mechanical properties of set cement through chemical transformations (see Chapter 10); however, the thermal dilation of the steel, cement, and rock can have a greater influence. All of these materials expand as the temperature increases and contract as the temperature decreases. Damage may occur owing to nonuniform heating. A portion of the material that is being heated might be prevented from expanding, while an unheated portion might be subjected to forced expansion. This generates stresses in the set cement that may lead to failure or debonding. To determine the thermoelastic behavior, such stresses must be added to those generated by elasticity. Set cement, rocks, and tubulars will follow the same behavior, although they will differ quantitatively.

The deformation caused by thermal effects in absence of stress is given by

\[ \varepsilon = \beta T, \]  

where \( \beta \) is the coefficient of linear thermal expansion and \( T \) is the temperature. Therefore, for the stress-strain relationship:

\[ \varepsilon_x = \beta T - \frac{\sigma_x}{E}, \]

\[ \varepsilon_y = \beta T - \frac{\sigma_y}{E}, \]

\[ \varepsilon_z = \beta T - \frac{\sigma_z}{E}, \]

and

\[ \gamma_{xz} = -\frac{\tau_{xz}}{G}. \]

To calculate the temperature change with time, one uses the conduction equation:

\[ \frac{\partial^2 T}{\partial x^2} + \frac{\partial^2 T}{\partial y^2} + \frac{\partial^2 T}{\partial z^2} = \frac{\rho c}{K} \frac{\partial T}{\partial t}, \]  

(8-18)

where \( K \) is the thermal conductivity, \( \rho \) the density, and \( C \) the specific heat. A temperature gradient will develop and, as shown in Fig. 8-7, a heat front will move with time.

**8-3.4 Poroelasticity**

The pore pressure can be expected to change in the cement sheath during the life of the well because, just after the hydration and the resulting water consumption, the cement pore pressure drops to a very low value (Chapter 9). Once the cement has set, fluid from the formation will flow into the set cement to equilibrate the pressure, and the set-cement pore pressure will increase. A rapid increase of wellbore pressure and temperature will also lead to a pore-pressure increase.

Pore fluids in cement play an important role because they support a portion of the total applied stress. Thus, only the remainder of the total stress, the effective stress component, is carried by the cement matrix (Fig. 8-8). In 1923, Van Terzaghi first introduced the effective-stress concept for one-dimensional consolidation of soils, and proposed the following relationship:

\[ \sigma' = \sigma + p_{pore}, \]  

(8-19)

where \( \sigma \) is the total applied stress, \( \sigma' \) is the effective stress governing the consolidation of the material, and \( p_{pore} \) is the pore pressure (note that if compressive stresses are taken to be positive, the equation is \( \sigma' = \sigma - p_{pore} \)). Biot (1941, 1956) later proposed a consistent theory to account for the coupled diffusion and deformation processes that are observed in elastic materials. For time-independent processes, this poroelastic material behavior is similar to that of an elastic solid when the stresses in Eq. 8-14 are replaced by effective stresses such that

\[ \sigma' = \sigma + \alpha p_{pore}. \]  

(8-20)

This poroelastic constant, \( \alpha \), varies between 0 and 1, and describes the “efficiency” of the fluid pressure in counteracting the total applied stress. Its value depends on the pore geometry and the physical properties of the solid.

Another similarity is that fluids diffuse through set cement in a manner similar to temperature. Assuming
that the set cement is incompressible and the pore fluid is slightly compressible, the diffusion equation is
\[
\frac{\partial^2 p_{\text{pore}}}{\partial x^2} + \frac{\partial^2 p_{\text{pore}}}{\partial y^2} + \frac{\partial^2 p_{\text{pore}}}{\partial z^2} = \frac{\phi \mu c}{k} \cdot \frac{\partial p_{\text{pore}}}{\partial t}, \quad (8-21)
\]

with \(p_{\text{pore}}\) the pore pressure, \(\phi\) the porosity, \(\mu\) the viscosity of the fluid, \(k\) the permeability, and \(c\) the fluid compressibility.

Permeability measurements use this diffusion equation (Appendix B). In this case one assumes that the fluid is incompressible.

\[
q = \frac{kA(\Delta p)_{\text{pore}}}{\mu L}, \quad (8-22)
\]

where \(q\) is the flow rate, \(A\) the sample cross section, and \(L\) the sample length.

In reality, however, solid materials are compressible. This compressibility, which changes the porosity of the solid when stress and/or pore pressure is applied, means that any stress change induces a pore-pressure change. One cannot dissociate the pore-pressure changes from the rock deformation. Two basic mechanisms highlight this coupled behavior (Detournay and Cheng, 1993).

- An increase of pore pressure induces cement dilation.
- A compression of the cement produces a pore pressure increase if the fluid is prevented from escaping the porous network.

When the fluid is free to move, pore-pressure diffusion introduces a time-dependent character to the mechanical response of the set cement. The set cement will react differently according to the loading rate and the ability of the cement matrix to accommodate the resulting pore-pressure fluctuation.

Hence, two limiting behaviors must be introduced: drained and undrained responses. One limiting case is realized when a load is instantaneously applied to a porous cement. In this case the excess fluid pressure has no time to diffuse; the medium will react as if it were undrained. Undrained values of Young's modulus and Poisson's ratio must be used in this situation. To determine undrained values, one performs a compression test as shown in Fig. 8-9a, in which the pore fluid is not allowed to escape from the sample. On the other extreme, if the pressurization rate is sufficiently slow and the diffusion has ample time to drain excess pressure areas, the cement will be less stiff, or more compliant. The stiffening effect during undrained deformation is greater if the pore is filled with a relatively incompressible liquid, rather than a relatively compressible gas.

To determine drained elastic values (which are the intrinsic elastic properties of the sample), one performs a compression test as shown on Fig. 8-9b, in which the pore fluid is allowed to escape from the sample and the loading rate is low enough to prevent the generation of excess pore pressure in the sample.
8-3.5 Plastic behavior

Most set cements exhibit nonreversible deformations after unloading, or at least a nonunique relationship between stress and strain. This means that set cements are not perfectly elastic materials, and a number of theories have been developed to model such behavior. They include the theories of plasticity, damage mechanics, and time-dependent analysis (creep). As an example, the theory of elastoplasticity will be briefly described.

Fig. 8-10 shows the stress-strain relationship of an ideal cylindrical elastoplastic sample. From O to A, the relation between stress and strain is linear, and the slope of the curve is the Young’s modulus, $E$. The stress-strain relationship does not change if the sample is unloaded in this region. This is the region in which the theory of elasticity applies. Beyond Point A, the slope of the curve decreases. Moreover, if one unloads the sample in this region, say at Point B, the unloading portion does not follow the same path as the loading portion but is perfectly linear with a slope $E$. At zero stress, part of the deformation has not been recovered. This unrecovered deformation represents the plastic-strain component in the theory of elastoplasticity. The Point A is actually the initial yield stress of the cement. During reloading, the sample behaves as a perfectly elastic solid up to the Point B, which is the new yield stress. The increase of the yield stress with the increase of plastic strain is called strain hardening; a decreasing yield stress with plastic strain is also possible, and is called strain softening. A perfectly plastic material is a material with no strain hardening or softening. As shown in this example, the yield stress is a function of the loading history.

In elastoplasticity, part of the strain is predicted by the theory of elasticity. Any strain increment that is associated with a stress increment is the sum of an elastic component and a nonelastic component:

$$\delta \varepsilon = \delta \varepsilon_{el} + \delta \varepsilon_{pl},$$

(8-23)

where $\delta \varepsilon$ is the total-strain increment, $\delta \varepsilon_{el}$ is the elastic-strain increment, and $\delta \varepsilon_{pl}$ is the plastic-strain increment. Unlike the elastic-strain component, the plastic-strain component cannot be recovered during unloading. To predict the plastic-strain increment one needs a yield criterion that indicates whether plastic deformation occurs, a flow rule that describes how the plastic strain develops, and a hardening law.

The yield criterion is a relationship between the stresses that is used to define the conditions under which plastic deformation occurs. In three dimensions, this is represented by a yield function that is a function of the state of stress and a hardening parameter:

$$f(\sigma_1, \sigma_2, \sigma_3, M) = 0.$$

(8-24)

The hardening parameter, $M$, determines the evolution of the yield curve with the amount of plastic deformation of the material. For further details on elastoplasticity, the reader is referred to Hill (1951) and Chen and Han (1988).

8-3.6 Creep of cement

Creep is a general term that covers the time-dependent deformations of the set-cement matrix (not to be confused with the time-dependent deformation caused by pore fluid flow or temperature diffusion). All set cements present some creep behavior. Creep has been thoroughly studied for concrete to prevent the failure of a concrete structure after a given amount of time, but has been poorly studied in oilwell cements even at ambient conditions.

As with plasticity, deformation caused by creep can be added to the instantaneous elastic deformation

$$\varepsilon = \varepsilon_{el} + \varepsilon_c(t),$$

(8-25)

where $\varepsilon_c(t)$ is the time-dependent deformation. This deformation can be permanent (e.g., viscous deformation) or reversible (time-dependent elasticity). Generally speaking, at low loads the deformation will be time-dependent elastic, while at higher loads, viscous deformation will dominate.

In general, the material creeps to reduce high shear stresses. This process can be unstable, leading to material failure. A typical example is the flow of salt zones. To avoid high shear stresses at the wellbore wall, they tend to fill in and close the wellbore. Once the wellbore is closed, the flow will stop.
8-3.7 Set-cement strength and set-cement failure

Set-cement failure occurs when cracks or discontinuities appear in the matrix. To achieve set-cement failure, the cracks must be large enough to cause the separation of fragments. The failure can be brittle or ductile (Fig. 8-11). A brittle failure means that failure occurs in the elastic section of the stress-strain deformation curve. Cracks initiate and propagate very quickly. Brittle failure is often unstable because the elastic energy released by the cracking process is higher than the surface energy consumed when cracks are created. In a crushing test, this is characterized by shattering of the set cement and fragments flying away. Set cements are brittle in tension, under impact loading, and during a compressive strength test at low confining pressure. Ductile failure means that failure occurs in the plastic regime, when permanent deformation is created. Set cements exhibit a ductile failure under confining pressure. Ductile failure is more advantageous for cement–sheath integrity in a tectonic environment, because the set cement will deform significantly before being damaged. In some cases the cement will be able to flow without cracking. This is especially common with porous or flexible cements at high confining pressure.

To estimate the initiation of cement failure, one uses a failure criterion. A failure criterion is usually a relationship between the principal effective stresses, representing a limit beyond which instability or failure occurs. The Terzaghi effective stress is used in the failure criterion

\[ \sigma' = \sigma + p_{\text{pore}}. \] (8-26)

Several criteria have been proposed in the literature for various applications. The more popular criteria include the following.

- The maximum tensile stress criterion states that failure initiates as soon as the maximum effective principal stress reaches the tensile strength, \( S_{\text{tens}} \), of the material:

\[ \sigma_1' = S_{\text{tens}}. \] (8-27)

- The Tresca criterion states that failure occurs when the maximum shear stress, \( (\sigma_1 - \sigma_3)/2 \), reaches a characteristic cohesion value, \( Y_{co} \):

\[ \sigma_1 - \sigma_3 = 2Y_{co}. \] (8-28)

- The Mohr-Coulomb criterion states that, for compressive failure, the shear stress tending to cause failure is opposed by the cohesion of the material and by a factor analogous to the coefficient of friction multiplied by the effective normal stress acting across the failure plane.

\[ |\tau| = Y_{co} - \tan(\Phi)\sigma_n'. \] (8-29)

where \( \Phi \) is the angle of internal friction and \( Y_{co} \) is the cohesion. The Mohr-Coulomb failure criterion can be rewritten in terms of principal stresses to give \( \sigma_3 \) at failure in terms of \( \sigma_1 \) (recall that tensions are positive, and under this convention, \( \sigma_1 \) is the confining stress):

\[ \sigma_3' = -\sigma_c + \tan^2\left(\frac{\pi}{4} + \frac{\Phi}{2}\right)\left(\sigma_1'\right) \] (8-30)

where \( \sigma_c \) is the compressive strength.

This criterion shows an increase of compressive strength with an increase of confining pressure. As shown above, the Tresca and Mohr-Coulomb criteria do not include the influence of the intermediate stress, \( \sigma_2 \). Experimental evidence shows that, in many cases, it is a good approximation. However, other criteria include the effect of \( \sigma_2 \).
8-3.8 Influence of confining pressure on set-cement behavior and failure

In a downhole situation, especially when the rock is creeping or when large tectonic stresses are present, the cement will be subjected to confining pressure. Increased confining pressure leads to increased cement strength, as predicted by the Mohr-Coulomb failure criterion and also by the transition from a brittle to a ductile material. Fig. 8-12 shows an example of the influence of the confining pressure on a cement sample. The tests were carried out as shown in Fig. 8-4, but each test was performed at a different confining-pressure value, $p_{\text{con}}$. The set-cement strength does indeed increase with confining pressure, but in reality this increase is not the linear one predicted by the Mohr-Coulomb criterion. An empirical law relating the cement strength to the confining pressure might be preferred.

One key feature of set cements under confining pressure is that they quickly become fully plastic with strain hardening, and thus failure is no longer observed. Another characteristic is that, because cements are highly porous, they will compact quickly under confining pressure (if the sample is drained). During compaction, the set-cement porosity decreases. This is the main cause of strain hardening, as the cement becomes stronger with decreased porosity (unless the porosity is so high that the matrix collapses).

8-3.9 Postfailure behavior of set cement

There are cases when the set cement will be subjected to excessive loads and vibration (e.g., during window drilling), leading to failure. In such cases, to ensure that the damaged set cement does not fall apart, it is important to control the postfailure behavior. As mentioned above, conventional set cements are brittle materials at low confining pressures. When cracks are initiated they can propagate very quickly. Unstable failure occurs because the elastic energy released by the cracking process is higher than the surface energy consumed by the creation of cracks. To control the failure, one must unload the cement sufficiently to release the elastic energy. In a controlled experiment, the area below the stress-strain curve is exactly the energy per unit volume consumed to propagate the crack. In a bending test (Fig. 8-13) or a direct-tension test, this energy per unit volume is called toughness. Models have been developed to describe tensile-crack propagation based on this type of relationship (Bosma et al., 1999).

However, in difficult cases in which conventional set cements are so brittle that uncontrolled failure is inevitable, high-toughness cements are required. High-toughness cements are designed so that the surface area below the stress-strain curve is sufficiently great to ensure that, when cracks propagate, they do so in a stable manner. Ideally the cracks do not extend or coalesce; instead, small microcracks form.
The most efficient way to promote high cement toughness involves the addition of fibers or microribbons to the cement matrix (Chapter 7). Fibers resist breakage when traversed by a microcrack and, up to a certain load, remain bonded to the cement matrix. This also improves the tensile strength of the set cement. But the most dramatic effect is that the fibers hold the broken cement fragments together and prevent the generation of larger cracks (Xenakis et al., 1997). The toughness of set cements containing fibers can be significantly higher than that of conventional cement systems, even at low fiber concentrations; however, its efficiency depends on the chemical nature of the reinforcement (Park et al., 1999; Nataraja et al., 2000). High-toughness cements based on metallic microribbons have been used as shock-resistant kickoff plugs (Babasheikh et al.; 2003) (Chapter 14).

8-3.10 Shrinkage and expansion
Cement shrinkage and expansion are discussed in Chapters 2 and 9; however, in the context of the present discussion, it is necessary to revisit the subject. A review of the terminology surrounding this subject is useful to prevent confusion.

The fundamental mechanism responsible for cement shrinkage is the total chemical shrinkage (following the terminology of Justnes et al., 1994). As discussed in Chapter 2, the volume of the reaction products of cement hydration is less than that of the reactants. The total chemical shrinkage is the volume reduction that occurs as a consequence of cement hydration.

At 100% hydration, the total chemical shrinkage of Portland cement is about 6.25 cm³/100 g of cement (Powers, 1958). The total chemical shrinkage can be measured by placing cement paste in a container, surrounding it with water, and monitoring the water level versus time. This technique tends to underestimate the total chemical shrinkage because it assumes that the water has full access to the pores. This is not necessarily the case, as the permeability of the matrix decreases with time. Justnes et al. (1995) measured the total chemical shrinkage of various Portland cement compositions at ambient conditions (68°F [20°C] and atmospheric pressure). After 48 hr the total chemical shrinkage was found to be independent of the water-to-cement ratio—about 2.17 cm³/100 g of cement for neat Class G slurries (or 2.8 vol% for a water-to-cement ratio of 44 wt%). This difference between the results of Justnes and those of Powers indicates that at 48 hr the degree of hydration is only 2.17/6.25 = 0.35.

Once the cement begins to develop compressive strength, the total chemical shrinkage can occur as bulk shrinkage. Bulk shrinkage is the external volume reduction that can occur during the hydration of Portland cement. It is a mechanical response to the stresses and pore-pressure changes generated by chemical shrinkage.

Bulk shrinkage can create a microannulus between the formation and the cement, preventing the cement from fulfilling its role as a sealing material (Justnes et al., 1994; Justnes et al., 1995). When the set cement shrinks, it moves toward the casing. Formation of a microannulus can lead to gas leaks at the surface (even when production has ceased: Dusseault et al., 2000), or incorrect leakoff-pressure estimation (Zhou and Wojtanowicz, 1999).

Bulk shrinkage can be measured by placing cement paste in a flexible membrane, sealing the membrane, and monitoring the volume variations of the membrane. At the beginning of the experiment, the bulk shrinkage curve matches that of the total chemical shrinkage. Then the bulk-shrinkage curve flattens out as a rigid structure starts to form, preventing the total collapse of the material (Fig. 8-14). Total chemical shrinkage continues to occur, because cement hydration does not stop after the cement sets.

Using similar techniques in which the cement paste is isolated from the surrounding medium, several authors (Parcevaux and Sault, 1984; Chenevert and Shrestha, 1991; Bensted, 1991; Sabins and Sutton, 1991; Justnes et al., 1994; De Rozières and Sabins, 1995; Justnes et al., 1995; Justnes et al., 1996; Backe et al., 1997) have reported bulk shrinkage values of 0.5 to 5.0% by volume. Although these results were obtained under
a variety of temperature and pressure conditions, such a
wide range of results is probably caused by the formation
of free water during the experiments (Justnes et al.,
1996) and the failure to control the boundary conditions.
If bulk-volume variations are measured when the
cement has access to additional water during the test
e.g., by measuring the dimensional variation of an
annular ring mold or cylindrical sleeve filled with the
cement paste and placed in water), a bulk expansion
as high as 0.3% by volume is observed after the cement sets
de Rozières and Sabins, 1995). Uncontrolled bulk
expansion can be as harmful as bulk shrinkage, because
it can disrupt the casing/cement interface (Beirute
et al., 1988; Baumgarte et al., 1999). To avoid this prob-
lem, one must ensure that the cement has a lower
Young’s modulus value than the surrounding rock
(Baumgarte et al., 1999, Le Roy-Delage et al., 2000).

In the context of the mechanical properties of well
cements, the initial phase of shrinkage is not relevant
Setter and Roy, 1978). During this phase, the cement is
still a liquid slurry. During primary cementing, before
the cement slurry begins to set, the top of the cement
column moves downward to compensate for the volume
reduction (Chenevert and Shrestha, 1991). The bulk
shrinkage that occurs after a rigid network of hydration
products has formed and compressive strength begins to
develop is relevant to the mechanical properties.

Previous studies of cement shrinkage have shown two
key behaviors that can be easily linked to porous elasto-
plastic solid behavior controlled by effective stress
(Thiercelin et al., 1998). When cement has free access
to additional water, the external water flows into the
cement pore space to compensate for the total chemical
shrinkage, and almost no bulk shrinkage is observed. In
some formulations, an expansion might even be observed.
For this to occur, the cement permeability must be high
enough to allow the external fluid to invade the pore
structure (Appleby and Wilson, 1996). Restated in solid
mechanics terms, the pressure and saturation of the
fluid in the cement pores must remain constant during
cement hydration to avoid bulk shrinkage.

When cement has no free access to water (e.g.,
because of the presence of an impermeable membrane),
total chemical shrinkage leads to pore-pressure reduc-
tion and eventual pore collapse. Restated in solid
mechanics terms, the cement compacts if the external
total stress remains constant and the internal pore
pressure decreases during cement hydration, leading
to an increase of effective mean stress. Note that the
chemical shrinkage can be so high that pore saturation
falls below 100%, and, because of capillary effects, a
negative pore pressure is observed.

8-4 Mechanical behavior of a cement
cased wellbore
8-4.1 State of stress in the cement sheath
To determine whether a cement sheath will fail or debond
in the annulus, one must calculate the state of stress.
The calculated stress is then entered into an expression
to determine whether failure is attained. To calculate
the state of stress, one must assume a deformation
behavior (e.g., elasticity) and consider the various
applied loads at specific boundaries such as the
casing/cement and cement/formation interfaces. In some
cases, the influence of temperature and pore pressure
must also be considered.

In recent years, various models have been devel-
oped to analyze the state of stress in the cement
(Thiercelin et al., 1997; Bosma et al., 1999; Gino di
Lullo and Rae, 2000; Fleckenstein et al., 2000;
Philippacopoulos and Berndt, 2002; Pattillo and
Christansen, 2002). They are based on analytical solu-
tions, numerical solutions, or a combination of both.

8-4.2 Modeling the cement sheath using
thermoelasticity
In this section the modeling of stresses in a cased
wellbore containing a finite number of concentric
casings is briefly described. A cross section of the well-
bore is shown in Fig. 8-15. The stresses in the cement
are calculated assuming that casing, cement, and rock
are thermoelastic materials. The casing/cement and
cement/rock interfaces are also assumed to be either
fully bonded or unbonded. Finally, it is assumed that the
cement is under no internal “effective” stress after
setting. This final assumption is obviously a strong

![Fig. 8-14. Chemical shrinkage (green line) and bulk shrinkage (red
line) as a function of time for a cement with a water/cement ratio
by weight of 0.4 (after Justnes et al., 1995). Reprinted with permis-
sion from Thomas Telford Limited.](image-url)
simplification. It is known that, after placement, the cement slurry unloads as its gel strength develops (Chapter 9). Field observations (Cooke et al., 1983; Morgan, 1989) tend to confirm that the total stress in the cement drops to at least the hydrostatic pressure given by the saturating formation fluid (mainly water), justifying the zero-effective stress assumption. However, in some cases the pore pressure can drop below the hydrostatic pressure, especially in a casing-to-casing configuration. One can imagine a variety of situations, depending on the cement properties, cementing procedure, formation permeability, and nature of the saturating fluid. Nevertheless, in the absence of better information, this simplification is appropriate. Consequently, to study the cement behavior, only the variations of pressure, stress, or temperature that occur after the cement sets are considered.

The geometry of the problem is axisymmetric, with the axis of symmetry being the wellbore axis, allowing the use of cylindrical coordinates $r$, $\theta$, and $z$. The simplest situation is when the boundary and initial conditions (wellbore and far-field states of stress and temperature) are independent of $\theta$. The variables of interest are then the radial displacement; radial stress, $\sigma_r$; tangential stress, $\sigma_\theta$; axial stress, $\sigma_z$; the shear stress, $\tau_{rz}$; and the temperature, $T$ (which in practice is the temperature difference from a reference state). The tangential stress is a principal stress. The radial and tangential stresses are shown in Fig. 8-16. The sign convention is that tensile stresses are positive. Thermoelasticity provides a linear relationship between the strains $\varepsilon_r$, $\varepsilon_\theta$, $\varepsilon_z$, and $\gamma_{rz}$, stresses, and temperature, $T$.

\[
\varepsilon_r - \beta T = \frac{\sigma_r}{E} - \frac{\nu}{E} (\sigma_\theta + \sigma_z)
\]

\[
\varepsilon_\theta - \beta T = \frac{\sigma_\theta}{E} - \frac{\nu}{E} (\sigma_r + \sigma_z)
\]

\[
\varepsilon_z - \beta T = \frac{\sigma_z}{E} - \frac{\nu}{E} (\sigma_r + \sigma_\theta)
\]

\[
\gamma_{rz} = \frac{1}{G} \tau_{rz},
\]

where $E$, $\nu$, and $G$ are respectively the Young’s modulus, Poisson’s ratio, and shear modulus, and $\beta$ is the coefficient of linear thermal expansion.

The temperature distribution as a function of time is obtained from the heat diffusion equation, which is expressed under the assumption that the initial and boundary conditions do not depend on $\theta$, as

\[
\frac{\partial^2 T}{\partial r^2} + \frac{1}{r} \frac{\partial T}{\partial r} + \frac{\partial^2 T}{\partial z^2} = \frac{\rho C}{\lambda} \frac{\partial T}{\partial t},
\]

where $\lambda$ is the thermal conductivity, $\rho$ the density, and $C$ the specific heat.

Plane strain is also assumed, meaning that there is no axial movement. This is usually a good assumption, although axial movement could develop when casing sections are being heated and axial casing deformation is not prevented at the surface.

The stress model uses analytical solutions that have been presented in Thiercelin et al. (1997). The solution is constructed with the conditions that the radial displacements and radial stress are continuous across the interface between two materials and the radial stress is compressive. If the radial stress is tensile (or
above a small value that can be considered as cement adhesion at the interface), debonding occurs, radial displacement is discontinuous, and the radial stress is set to zero. The inner surface of the inner casing has an imposed radial stress condition, given by the variation of wellbore pressure on its inner surface.

Heat transport takes place by conduction, as described above. To calculate the evolution of temperature with time, it is often more convenient to use a numerical technique such as the finite-difference technique or the finite-element technique. The influence of temperature on the state of stress is a function of thermal expansion of the various materials. Time is introduced by the heat-diffusion process.

8-4.3 Influence of wellbore pressure increase

The most damaging wellbore pressure increases often occur during a pressure test of the casing. It is indeed unfortunate that, by checking the casing integrity, one can damage the cement sheath. An increase of mud weight, a hydraulic fracturing treatment, or a perforation test can also generate large wellbore pressure increases. A wellbore pressure increase induces a radial elastic expansion of the casing, which in turn loads the cement.

The effect of a pressure increase on the state of stress in the cement sheath is shown in Figs. 8-17 and 8-18, in which the radial and tangential stresses in the cement are shown as a function of the distance from the wellbore axis. In this case, the Young’s moduli of the steel, cement, and rock are $29.0 \times 10^6$ psi [200 GPa], $0.725 \times 10^6$ psi [5 GPa], and $1.45 \times 10^6$ psi [10 GPa], respectively. The Poisson’s ratios are 0.27, 0.15, and 0.2, respectively. The wellbore pressure increase is 2,900 psi [20 MPa]. The openhole diameter is 7 in. [178 mm], the casing outside diameter (OD) is 5 in. [127 mm], and the casing weight is 23.20 lbm/ft [34.53 kg/m]. Because we are using linear elasticity with a single loading condition, the stress values are a linear function of wellbore pressure. Thus, doubling the wellbore pressure results in doubling the value of the stresses in the cement.

These figures show that, in this case, the radial stress is compressive and the tangential stress is tensile. The tangential stress is about half the absolute value of the radial stress. Because cements are about 10 times weaker in tension than in compression, the cement failure will occur in tension. Tensile failure appears when the tensile stress is greater than or equal to the tensile strength. The highest value of the tangential stress is at the steel/cement interface; therefore, this is where failure should first occur. In this case, cement failure will correspond to the initiation and propagation of tensile radial cracks, because tensile cracks propagate perpendicular to the direction of the maximum tensile stress. If the wellbore pressure increases by 2,900 psi [20 MPa], the value of the tangential stress at the steel/cement interface can be used to calculate the tensile strength the cement must have to avoid failure.

The cement Young’s modulus has a strong influence on the cement sheath response. This is demonstrated in Fig. 8-19, which shows the tangential stress as a function of distance from the wellbore axis. In this case the Young’s modulus of the cement is $0.725 \times 10^6$ psi [500 MPa]. This time the tangential stress in the cement is less tensile, even compressive, near the cement/rock interface. This is because of the mechanical support pro-
vided by the rock. In fact, the resistance of the cement sheath is increased, as this effect usually compensates for the decrease of cement strength often associated with a decrease of Young's modulus. The mechanical support is actually related to the ratio of the set cement's Young's modulus to the rock's Young's modulus, so a rock with a higher Young's modulus will show similar behavior in reducing the tensile stress in the cement. This also happens when the set cement's Poisson's ratio is higher. Obviously other issues, such as casing protection and casing support, must be considered.

These results demonstrate that, to determine whether the cement will fail owing to a wellbore pressure increase, one must know the tensile strength of the cement and the elastic properties of the cement and the rock. The geometry of the cased wellbore is also an important parameter. For example, increasing the casing thickness will decrease the tensile strength requirement.

A field example was described by Le Roy-Delage et al. (2000). A cemented cased section of a well, in which the slurry was displaced with a low-density mud, was to be subjected at a later stage to a pressure increase of 6,500 psi [44.8 MPa]. This pressure increase was the consequence of a mud-density increase, required to drill through a salt zone located at a deeper location. The openhole diameter was 12 in. with a 9%-in., 53.5-lbm/ft casing. The Young's modulus and Poisson's ratio of the rock were 3.6 \times 10^6 psi [24,800 MPa] and 0.25, respectively. The mechanical properties of the cement formulations used for this application are shown in Table 8-2. The slurry-density requirement was 16 lbm/gal [1,920 kg/m^3]. Table 8-2 shows that the tangential stress imposed on the conventional cement (Formulation A) largely exceeds the cement's tensile strength, and that cement failure in tension is expected. A less stiff cement containing flexible particles, which gains support from the rock, is more appropriate (Formulation B). In this case, the tangential stress does not exceed the tensile strength of the cement, even though the actual tensile strength is less than that of the conventional cement.

### 8-4.4 Influence of wellbore temperature increase

The calculation of stresses on set cement caused by a temperature increase involves additional parameters such as the density, specific heat, thermal conductivity, and the coefficients of thermal expansion of the various materials. For simplification one can assume that the coefficients of thermal expansion of the steel, cement, and rock are the same: $1.3 \times 10^{-5}$ K$^{-1}$. The complete set of thermoelastic properties is given in Table 8-3. Other material parameters are the same as in the example in Section 8-4.3, except for the stiffness of the cement, which, in this example, is higher than that of the rock.

The radial and tangential stresses in the cement show the same pattern as that during a wellbore pressure increase, with the generation of high tensile tangential stress in the set cement. The stresses are first generated by the rapid thermal dilation of the casing. Then, as heat diffuses through the set cement and eventually into

### Table 8-2. Cement Failure as a Function of Cement Properties During a Wellbore Pressure Increase

<table>
<thead>
<tr>
<th>Formulation</th>
<th>A (Conventional)</th>
<th>B (Elastic)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tensile strength (psi [MPa])</td>
<td>566 [3.9]</td>
<td>305 [2.1]</td>
</tr>
<tr>
<td>Young's modulus (psi [MPa])</td>
<td>1,311,000 [9,041]</td>
<td>376,000 [2,594]</td>
</tr>
<tr>
<td>Poisson’s ratio</td>
<td>0.15</td>
<td>0.22</td>
</tr>
<tr>
<td>Tangential stress at wellbore (psi [MPa])</td>
<td>998 [6.88]</td>
<td>138 [0.95]</td>
</tr>
<tr>
<td>Failure</td>
<td>Yes</td>
<td>No</td>
</tr>
</tbody>
</table>

### Table 8-3. Assumed Thermal Properties of Steel, Cement, and Rock

<table>
<thead>
<tr>
<th>Property</th>
<th>Steel</th>
<th>Cement</th>
<th>Rock</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solid density (kg/m$^3$)</td>
<td>8,000</td>
<td>1,900</td>
<td>2,100</td>
</tr>
<tr>
<td>Specific heat (J/kg-K)</td>
<td>500</td>
<td>2,100</td>
<td>1,900</td>
</tr>
<tr>
<td>Thermal expansion coefficient (K$^{-1}$)</td>
<td>$1.3 \times 10^{-5}$</td>
<td>$1.3 \times 10^{-5}$</td>
<td>$1.3 \times 10^{-5}$</td>
</tr>
<tr>
<td>Thermal conductivity (W/m-K)</td>
<td>15</td>
<td>1.0</td>
<td>1.0</td>
</tr>
</tbody>
</table>
the rock, stresses are generated by the thermal dilation of the cement. Fig. 8-20 shows the tangential stress in the cement, 1 min after a 360°F [200°C] temperature increase in the well. The tangential stress is compressive near the steel/cement interface and tensile near the cement/rock interface. This behavior is caused by the nonuniform thermal expansions of the materials. The temperature in the region near the well is higher than that further away. Compressive tangential stress is generated in this region because the thermal expansion is confined by the cooler materials in the surrounding region. Similarly, tensile stress is generated in the surrounding region that is being pressurized by the near-wellbore region. As temperature diffuses through the cement, the stress pattern will evolve. The cement achieves a more uniform temperature and is therefore under less stress.

![Stress vs. Distance](image)

**Fig. 8-20.** Tangential stress as a function of wellbore radius after 1 min.

This process is similar to a pressure increase, but is more complex owing to the influence of the temperature diffusion in the set cement and in the rock and the existence of a temperature gradient resulting in the nonuniform thermal dilation of a given material. A detailed analysis as a function of time is therefore required.

A second field case addresses one of the most severe conditions a cement sheath would ever experience in a well: steam injection (Le Roy-Delage et al., 2000). For this well, the temperature was increased to 400°F [204°C] from 120°F [49°C]. The openhole diameter as measured by the caliper was 13 in. [330 mm]. The casing was 9½ in. [244 mm] OD and 40 lbm/ft [59.53 kg/m], and the Young's modulus and Poisson's ratio of the rock were 580,000 psi [4,000 MPa] and 0.15, respectively. The cement density varied from 12 lbm/gal [1,440 kg/m³] to 14 lbm/gal [1,680 kg/m³]. The operator required a low-permeability cement with a final compressive strength of at least 1,500 psi [10 MPa]. As shown in Table 8-4, a conventional 14-lbm/gal [1,680 kg/m³] cement (Formulation C) would not support the stress generated by such a temperature increase. The thermal expansion of the casing imposes a tensile tangential stress well above the tensile strength of the cement sheath. Moreover, because the well was shallow, the formation (sandstone) had a low Young's modulus and would not prevent large deformations of the cement sheath. The model shows when and where the tensile stress reaches the most critical value in the cement sheath. In this case, the most critical location is 5.2 in. [132 mm] from the wellbore axis. Various formulations were tested. Formulation D, containing flexible particles, was able to provide very low stiffness while retaining sufficient compressive strength and low permeability. Table 8-4 demonstrates that this cement will not crack under the thermal loading, because the tangential stress at the critical location is always below the value of the cement's tensile strength.

<table>
<thead>
<tr>
<th>Formulation</th>
<th>C</th>
<th>D</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tensile strength (psi [MPa])</td>
<td>334 [2.3]</td>
<td>218 [1.5]</td>
</tr>
<tr>
<td>Young's modulus (psi [MPa])</td>
<td>545,000 [3,759]</td>
<td>177,000 [1,221]</td>
</tr>
<tr>
<td>Poisson's ratio</td>
<td>0.16</td>
<td>0.24</td>
</tr>
<tr>
<td>Maximum value of tangential stress (psi [MPa])</td>
<td>799 [5.51]</td>
<td>149 [1.03]</td>
</tr>
</tbody>
</table>

**Table 8-4. Cement Failure as a Function of Cement Properties During a Wellbore Temperature Increase**

- **8-4.5 Influence of wellbore pressure and temperature decrease**

A decrease of wellbore temperature and pressure creates tensile stress at the cement/rock and cement/casing interfaces, if the cement is assumed to be fully bonded to the rock and casing. The radial and tangential stresses are then exactly the same as in Fig. 8-17 and Fig. 8-18, but with a sign change (again a consequence of elastic behavior). Radial stress is now tensile and, because the adhesion forces are often very small, debonding will occur. Whether debonding will occur at the rock/cement or cement/casing interface depends on numerous parameters, such as the presence of...
of a thick mud cake at the cement/rock interface. As demonstrated by bond logs, debonding often occurs at the casing/cement interface, and a microannulus is created.

The following field case is an example of the problem, although more severe cases have been encountered. An intermediate section of a gas well is analyzed. The open-hole diameter is 12 1/4 in. [311.1 mm], with a 9 5/8-in. [244-mm], 66.8-lbm/ft [99.41-kg/m] casing. During completion the heavy mud used to drill the deeper section was replaced by a completion fluid with a density close to water. This resulted in a 3,290-psi [23-MPa] pressure drop in front of the casing. However, during production, the temperature of the completion fluid increased by 36°F [20°C]. The combined effect of the pressure decrease and temperature increase is shown in Fig. 8-21. First, a 58-μm microannulus was created. However, as the casing was being heated, it dilated and reduced the size of the microannulus to 28 μm, which is still sufficient to create a gas leak. The only solution would be to use an expanding cement (Seidel and Greene, 1985; Moran et al., 1991; Baumgarte et al., 1999, Le Roy-Delage et al., 2000; Chapter 7). However, as mentioned earlier, the cement must be more flexible than the surrounding rock (Baumgarte et al., 1999, Le Roy-Delage et al., 2000) to ensure good bonding.

8-4.6 Casing support, perforation and fracturing

The compressive strength required to support casing and survive perforation and hydraulic fracturing treatments has been a subject of debate for many years. Traditionally it was believed that the higher the compressive strength of the cement, the better the result would be. Recent developments allow a clarification of the subject.

The situation concerning casing support is straightforward. Casing support means that the set cement bonded to the casing has sufficient strength to support the weight of the casing plus the weight of the drillstring during shoe drilling or other events. The strength of interest is the shear bond strength, often empirically associated with the tensile strength of the cement.

Casing support is usually calculated using the following equation.

\[ F = 0.969 S \times d \times h, \]

where \( F \) is the load to break the cement bond in lbf, \( S \) is the compressive strength in pounds per square inch (assuming it is 10 times the shear-bond strength), \( d \) is the outer diameter of the casing string in inches, and \( h \) is the height of the cement column in feet.

Assuming that only 5% of the cement is supporting the load (which can be viewed as a very strong safety factor), it can be shown (di Lullo and Rae, 2000) that, even with the heaviest casings, the required compressive strength is around 143 psi [1 MPa]. This is well below the accepted 500-psi [3.5045-MPa] standard. In practice, with normal casings, 50-psi [0.35-MPa] compressive strength would be sufficient, especially if one considers that the confining pressure might even increase the strength.

For perforating and fracturing, a required compressive strength of around 1,000–1,400 psi [7–10 MPa] is often mentioned. The earlier discussion shows that this is not necessary, because the pressures generated during perforating and hydraulic fracturing result in a wellbore-pressure increase. In many cases, a compliant or highly flexible cement with low compressive strength will provide better support than a strong stiff cement. The cement does not need to have high compressive strength to fulfill its role in casing support or zonal isolation.

Field observations support this statement (Deeg et al., 1999). However, the flexible cement must be of good quality and proven resistant to shock. For example, highly permeable cements saturated with water might suffer excessive shock because of the generation of excessive pore pressure in the cement matrix.

8-4.7 Tectonics, subsidence, and formation creep

Tectonic stresses, subsidence, and formation creep can lead to loading of the cement by the formation and eventually the collapse of the casing. The loads involved are often so large (except in the case of formation creep) that it is practically impossible to prevent failure altogether. However, by using a careful completion design, one can at least retard the collapse.

When rock deformation or rock loading occurs, the cement can be strongly confined and compressed. Plastic flow of the cement leading to shear ductile failure would be the main deformation and failure mechanisms.
For these situations, it is necessary to know the cement behavior as a function of the confining pressure.

The influence of rock stresses or rock deformation on cement and casing failures can be grouped in three main loadings.

1. The first includes a more or less continuous loading of the cement bond and casing. It can be very isotropic if rock creep is involved, or strongly directional if tectonic stresses are involved (Fig. 8-22). The most remarkable example is the influence of tectonic stresses on cased wellbores in the foothills of Colombia, South America (Last et al., 2002), which leads to the ovalization of the casing string. Field data show that the presence of the cement sheath improves the stability of the casing owing to better load distribution on the casing, and that a ductile cement that deforms before failure also helps. Their analysis is supported by a numerical study based on the finite element method, in which casing and cement elastoplastic behavior are taken into account. Overall, the main recommendation is to use a dual cemented string. The cement between the two strings has the goal to strengthen and stiffen the dual string, so it must be as strong and stiff as possible.

2. The second loading is linked to the activation of natural faults (Fig. 8-23) or the creation of new ones. This is typical of the overburden response to strong compaction and leads to severe shearing of the casing. Recommendations (Dusseault et al., 1998) are essentially based on either a strengthening of the casing (dual cemented string or thicker casing) or an increase of system compliance such as the underreaming of the zone, the use of ductile cements, and even the avoidance of cementing. Pattillo and Kristiansen (2002) used the finite element method to analyze the stress field in the casing and cement and showed that ductile cement aids stability by avoiding extreme casing deformation.

3. The last loading is axial compression of the casing linked with the compaction of the formation adjacent to it. This leads to casing buckling (Fig. 8-24), essentially in poorly cemented zones. Heating of the casing will have the same consequences because of thermal vertical expansion. Experimental studies (Veeken et al., 1994) again show that the presence of the cement is essential to provide casing support and avoid buckling.
The overall recommendation to maintain wellbore stability as long as possible is to strengthen the casing as much as possible and to ensure that the annulus is fully cemented. The cement must have good plastic/ductile behavior and flow easily under stress to avoid casing pitching and to provide casing support.

Poor cement or microannulus formation can also lead to a gas or oil leak between the reservoir and the overburden. In overpressured reservoirs, such fluid leaks can lead to the pressurization of natural faults, which in turn become unstable. Shear reactivation and shear collapse of the casing can therefore be either promoted or induced by these leaks. Good bonding must be ensured.

8-5 Guidelines for cement design

To design a cement system that resists the downhole conditions, the following methodology is proposed.

- It is first essential to have a database of cements or alternate sealants with the desired mechanical properties (elastic parameters, compressive strength, tensile strength, shrinkage/expansion) at various temperatures and confining pressures. For example, having a variety of cement systems with low, medium, and high Young's moduli is recommended. The database allows us to know what can be achieved under various constraints such as slurry density, slurry rheology, and cost. Rock properties are also needed and can be obtained from sonic logs.

- The second step is to properly understand and describe the downhole situation to identify the cause of potential problems. This requires a review of all the events that may occur after the cement sets, such as a change of wellbore fluid, change of temperature, formation creep, subsidence, or other tectonic event. In situations in which the casing can be damaged by the external loading, determination of the casing failure mode (Section 8-4.7) from downhole information is necessary.

  Example: A casing has been cemented with a 0.821-psi/ft or 15.8-lbm/gal [1,900-kg/m³] cement displaced with a 0.509-psi/ft or 9.8-lbm/gal [1,174-kg/m³] mud. The reference pressure is the pressure applied inside the casing by the mud during cement setting, not the pressure applied by the cement in the annulus. The drilling of the next section, in which overpressured shales are encountered, requires a mud-weight increase to 0.914 psi/ft or 17.6 lbm/gal [2,109 kg/m³]. The maximum pressure increase is at the shoe, located at 3,000 ft [914.4 m]. The pressure increase is

\[
\frac{(2.109 - 1.174) \times 914.4 \times 9.81}{1,000} = 8.39 \text{ MPa}
\]

or

\[
(0.914 - 0.509) \times 3,000 = 1,215 \text{ psi}
\]

- The required cement mechanical properties to survive such a change of downhole conditions are then determined using a stress model of the cemented cased wellbore. The input data to the model include the well geometry; steel, cement, and rock properties; and the expected variation of downhole conditions. The cement properties are obtained from the database mentioned above.

- Cement selection using such a model is performed with an iterative process, though one can imagine that, in the future, the model will be able to determine the best configuration automatically. The best solution is the most cost-effective cement that does not fail under the input loading condition. The model can be used to provide recommendations on cement design by tuning the properties of the cement to minimize the expected problem. Unfortunately, in complex situations, such as in tectonically active areas, the modeling can be very involved.

- The model must also be able to predict whether the loading can induce the formation of a microannulus, and in that case it is necessary to select the cement accordingly (for example expanding cement with a Young's modulus lower than the rock properties).

- Finally, the integrity of the cement sheath should be monitored over time to validate the selection.

To help the field engineers design cements based on mechanical considerations, software tools that follow the above guidelines have been developed. An application of such software tools for the cementation of steam-assisted gravity drainage wells is given in Stiles and Hollies (2002). This stress analysis model software contains databases on cement, rock, and steel mechanical properties; a calculator to determine downhole stress conditions; a stress model to predict whether the cement will fail (as described in Section 8-4); and a tool to help in designing the cement.

This software tool greatly facilitates the design of special cement for long-term zonal isolation, and this type of software tool is recommended to design critical cases.
8-6 Conclusion

The determination of optimal long-term mechanical properties that cements must have to ensure zonal isolation is a relatively new approach in the oil and gas industry. It is therefore an area in which new development occurs at a high pace. The determination of cement mechanical properties under downhole conditions and the modeling of cased wellbore deformations are current topics of research. Numerous aspects are still poorly known, such as the influence of the slurry-to-solid transition on the initial state of stress, the role of cement pore pressure, and the modeling of cement expansion or shrinkage in a downhole environment. Nevertheless it is clear that cement strength is not the only key mechanical property, and that the cement's elastic properties play a significant role in maintaining the integrity of the cased wellbore. In most configurations, especially when the casing expands because of pressure increase or temperature increase, soft elastic cements are the best solution. Expanding cements must also have low Young's moduli to be properly confined by the rock and to play their role in preventing microannulus formation. Other configurations require high-strength, high-stiffness cements, such as the cement used in a double-string casing and in kickoff plugs. In a high-stress environment, it seems that the main requirement is that the cement must ensure isolation and keep the rock away from the casing as much as possible. To achieve its goal, it must be able to flow without cracking. Soft cements might help reduce the load to the casing when shear fault reactivation is a problem, in cases in which the slip of the fault is limited.

Cements and alternate sealants are being developed with properties that are more appropriate for downhole conditions than conventional oilwell cements. There is no doubt that new products with enhanced properties will continue to appear in the coming years.

8-7 Acronym list

OD  Outside diameter
UCA  Ultrasonic cement analyzer
9-1 Introduction

Annular fluid migration during drilling or well-completion procedures has long been recognized as one of the most troublesome problems of the petroleum industry. It is defined as the invasion of formation fluids into the annulus owing to a pressure imbalance at the formation face. The fluids may migrate to a lower pressure zone or possibly to the surface (Fig. 9-1). Gas migration is the most common form of annular fluid migration and no doubt the most dangerous (Carter and Slagle, 1970; Sutton and Faul, 1984). Gas migration is the primary focus of this chapter; however, most of the concepts presented here also apply to other formation fluids, such as shallow water (Stiles, 1997; Watters and Beirute, 1998).

Gas migration—also called gas communication or gas leakage (Carter and Slagle, 1970), annular gas flow (Garcia and Clark, 1976), gas channeling (Parcevaux et al., 1983), flow after cementing (Webster and Eikerts, 1979), or gas invasion (Bannister et al., 1983)—is a problem for both gas-producing and gas-storage wells. The severity of the problem ranges from the most hazardous (e.g., a blowout situation arising from a severe pressure imbalance during drilling or cementing) to the most marginal (e.g., a residual gas pressure of a few psi at the wellhead). In addition to surface-related difficulties, communication between two or more subsurface zones can occur. Such problems are more difficult to detect.

This chapter concentrates on gas migration after primary cementing. However, many of the elements of gas migration are similar to well control during drilling (Moore, 1974). Although drilling is beyond the scope of this chapter, some similarities between gas migration during cementing and gas migration during drilling are highlighted.

9-2 Practical consequences of gas migration

The potential consequences of gas migration following primary cementing are numerous, but not always immediately detectable. At the extreme, those that manifest themselves at the surface, e.g., sustained casing pressure or gas flow at the wellhead, may dictate well abandonment. More frequently, remedial cementing is performed until gas flow is stopped and gas pressure is reduced to a level compatible with the operator’s safety policy and local regulations. However, the efficiency of squeeze cementing in such circumstances is very poor for three essential reasons: (1) gas channels are difficult to locate, especially if they are less than 1 mm in size; (2) gas channels may be too small to be effectively filled by cement; and (3) the pressure exerted during the squeeze job is sometimes sufficient to break cement bonds or even to initiate formation fracturing, further worsening downhole communication problems. Furthermore, cement repair operations are expensive, especially offshore or at remote locations (Cooke et al., 1982). Therefore, preventing a gas migration problem is definitely preferable to attempts to repair it. A thorough discussion of remedial cementing appears in Chapter 14.
Gas migration between two or more subsurface zones, with no surface manifestations, is very difficult to detect (Fig. 9-1). In such cases, gas production may be impaired, gas may be diverted to an upper depleted zone (possibly followed by gas migration to the surface through another well), or the efficiency of stimulation treatments may be reduced (Cooke et al., 1982). Such downhole channeling can sometimes be evaluated by special methods such as noise logs (Garcia and Clark, 1976) or acoustic logs (Catala et al., 1984; Rang, 1987) (Chapter 15). Hydraulic communication testing is not recommended. If not properly designed and controlled, these tests may induce communication across properly cemented zones or aggravate minor cement-job defects. A complete discussion of cement-job evaluation is presented in Chapter 15.

### 9-3 Physical process of gas migration

Gas migration is a complex process that is influenced by many factors: fluid density control, mud removal, cement-slurry properties, cement hydration, and interactions between the cement, casing, and formation. The cementing industry first recognized gas migration in the early 1960s, when major gas-communication problems occurred in gas storage wells in the United States (Stone and Christian, 1974). Since then, the industry has worked diligently to understand the problem and find solutions.

Extensive research has been performed to understand the fundamentals of the physical process, and a vast quantity of literature describes various aspects of gas migration.

- Field case study analyses and experiments for making practical recommendations (Vidovskii et al., 1971; Stone and Christian, 1974; Garcia and Clark, 1976; Cooke et al., 1982; Lukkien, 1982; Al-Buraik et al., 1998)
- Laboratory investigations to improve the understanding of gas-migration fundamentals (Guyvoronsky and Farukshin, 1963; Carter and Slagle, 1970; Carter et al., 1973; Webster and Eikerts, 1979; Sabins et al., 1982; Bannister et al., 1983; Parcevaux, 1984b; Beirute and Cheung, 1990; Moroni et al., 1997; Calloni et al., 1999; Barlet-Gouédard et al., 2001)
- Development of technical solutions (Levine et al., 1979; Tinsley et al., 1979; Cheung and Beirute, 1982; Parcevaux et al., 1983; Stewart and Schouten, 1986; Sykes and Logan, 1987; Dean and Brennen, 1992)
- Applications of new products and techniques in the field (Kucyn et al., 1977; Watters and Sabins, 1980; Cheung and Myrick, 1983; Seidel and Greene, 1985; Sepos and Cart, 1985; Matthews and Copeland, 1986)
- Empirical qualitative prediction techniques (Sutton et al., 1984; Rae et al., 1989).

Successful numerical simulations of the process or scaled laboratory experiments that could allow a generalized and quantitative prediction of gas migration have not been reported.

### 9-3.1 Root causes for gas migration

Annular gas migration has three distinct root causes (Fig. 9-2).

1. The hydrostatic pressure in the annulus falls to a level that is less than or equal to the pore pressure of a gas-bearing zone.
2. Space in the annulus allows gas entry.
3. A path is present in the annulus through which the gas can migrate.

All three root causes must be satisfied for annular gas migration to take place. The root causes involve various factors inherent to the cementing process. These factors are described in this chapter.

![Fig. 9-2. Root causes of annular gas migration.](image-url)
hole) evolves with time. The physical state of the cement progresses from a liquid slurry during placement to a permeable gel during a limited static period, to a permeable, weak solid when setting, and finally to an impermeable solid after hardening. Thus, the physical process of gas migration is convenient to categorize according to when it occurs during the cementing operation (Fig. 9-3). Three major categories can be defined:

1. immediate gas migration (during placement)
2. short-term gas migration (postplacement)
3. long-term gas migration (postsetting).

### 9.3.2.1 Immediate gas migration

Immediate gas migration, also referred to as gas migration during placement, occurs between the start of the cementing operation and the end of cement placement, which is normally marked when the top wiper plug lands.

During this time period, gas migration results from the loss of hydrostatic-pressure overbalance against gas-bearing formations. Preventing gas migration during this stage is a relatively straightforward well-control matter, similar to that practiced during drilling. One of the first approaches to solving immediate gas migration was to simply increase the density of the fluid in the annulus. Such an approach can be dangerous, because the resulting increase in hydrostatic pressure can lead to lost circulation or formation fracturing. In 1970, Carter and Slagle recommended circulating the well before cementing to help remove any trapped gas bubbles that, if not removed before cement placement, would reduce the hydrostatic head of the fluid column.

The principal difference between well control during drilling and that during cementing is the free-fall or U-tubing phenomenon that occurs during the cement job (Chapter 12). Because of the density differences between the mud, preflushes, spacer, and cement slurry (or slurries), the hydrostatic pressure exerted at the formation face is not constant during the job (Beirute, 1984; Smith et al., 1987). If the hydrostatic pressure in the annulus falls below the formation gas pressure at any time, a gas release may occur that, by further relieving the hydrostatic pressure, may lead to an irreversible gas-entry process. Consequently, the cement-job design should be performed with a free-fall computer simulator to ensure that the hydrostatic pressure against critical zones is maintained between the pore and the fracturing pressure at all times during the cement job. An example is shown in Fig. 9-4 (Drecq and Parcevaux, 1988).

It should also be noted that casing reciprocation may cause the hydrostatic pressure in the annulus to fall because of a swabbing effect. This is especially probable...
during periods when the fluids in the wellbore are in a static state owing to free fall. As long as the hydrostatic pressure in the annulus remains greater than the formation gas pressure, no gas migration (other than that which occurs through dissolution and diffusion processes at the molecular level) should occur during the placement operation.

One final point should be made concerning density control during the cementing operation. Many large cement jobs are performed on a continuous-mix basis (i.e., “on the fly”). Density fluctuations may occur during the course of the job, resulting in the placement of a nonuniform column of cement in the annulus (Granberry et al., 1989). Such a condition may cause solids settling, free-water development, or premature bridging in some parts of the annulus. When the potential for annular gas migration exists, either batch mixing or process-controlled continuous mixing is recommended to ensure a homogeneous cement column.

9-3.2.2 Short-term gas migration
Short-term gas migration, also called postplacement gas migration, occurs between the end of the primary cementing operation (normally marked by the landing of the top wiper plug) and the setting of the cement. Short-term gas migration may occur anytime between a few minutes to a few days after the end of the cementing operation. Gas migration that occurs during this time period is perhaps the most complex to understand, difficult to predict, and problematic to prevent. For this reason, most industry work concerning gas migration has focused on this category.

The primary driver for the occurrence of gas migration during this stage is believed to be the decay of the annular pressure. This pressure decay can be attributed to a combination of several factors, including fluid loss, gel strength development, and chemical shrinkage of the cement during hydration. It can also result from the formation of annular bridges or the setting of mechanical devices such as packers that isolate hydrostatic-pressure transmission. Space for gas to enter the annulus during this stage can be created by fluid loss, free fluid, chemical shrinkage, and the inherent porosity of the slurry. The gas-migration path during the short-term stage is first through the cement-filtercake permeability and then through the permeability of the cement matrix.

9-3.2.3 Long-term gas migration
Long-term gas migration occurs after the cement has set, which may occur within a few hours after the end of the cement job. However, days, months, or even years are the usual time frame. Industry interest in understanding, predicting, and preventing long-term gas migration has increased in recent years because of environmental concerns about abandoned gas wells leaking gas into the atmosphere.

The primary driver for gas to migrate in the long term is the formation of a pathway for the gas to travel after the cement has set. After setting, a normal-density cement system becomes a solid with microporosity permeability. As a result, gas cannot migrate at any detectable rate within the partially water-saturated pores of the cement matrix. It should be noted that low-density cement systems with high water-to-cement ratios might exhibit fairly high permeabilities (0.5 to 5.0 mD). Therefore, it is possible for gas to flow, albeit at low rates, within the matrix of such cements and to eventually reach the surface. Such events may take weeks or months to appear as measurable phenomena at the surface, where they usually appear as slow pressure buildups in the shut-in annulus.

The path for long-term gas migration is more likely to be through a microannulus, a mud channel, a channel of bypassed lead cement slurry, a free-water channel, a dehydrated filtercake, or any mechanical failure of the cement sheath caused by imposed stresses. Space for entry can come from chemical shrinkage of the cement, bulk shrinkage of the cement, and dehydration of mud channels, free-fluid channels, and filtercakes. Because the cement has already set during this phase, it is no longer transmitting hydrostatic pressure across the gas zone.

9-3.3 Factors affecting gas migration
Numerous factors, many of which have been mentioned previously, may contribute to gas migration. A synopsis of these factors and how they relate to both the root causes and the categories of gas migration is presented in Table 9-1. It is important to note that one single factor does not cause gas migration, but rather a combination of several factors, depending upon the unique conditions in each well.

9-3.3.1 Fluid loss
Fluid loss from the cement slurry into the formation directly affects all three of the root causes of gas migration and therefore must be considered one of the main contributing factors. First, it may be responsible for a decrease in annular pressure owing to

- annular bridging
- increased slurry gelation effects caused by a reduced water content in the slurry
- a decrease in the height of the hydrostatic column owing to a slurry-volume decrease
- friction-pressure losses during the compaction resulting from a slurry volume decrease.
Second, owing to a volume decrease, fluid loss may create space within the cement matrix that gas can occupy. Finally, fluid loss may be responsible for controlling the filtercake permeability, which ultimately influences the migration path. Fluid-loss additives may also act indirectly to reduce the permeability of the cement slurry (Chapter 6).

The importance of fluid loss as a contributing factor to gas migration was first recognized by Carter and Slagle (1970). At that time, the respective influences of fluid-loss control and cement-slurry gelation were not fully understood. It was, however, pointed out that bridging or gelation owing to fluid loss could restrict the transmission of hydrostatic pressure. In 1975, Christian et al. derived a method for calculating the fluid-loss control required to prevent bridging of the cement across permeable formations during and after cement placement. In 1975, Christian et al. concluded that reducing the American Petroleum Institute (API) fluid-loss rate to less than 50 mL/30 min would reduce gas invasion and lessen cement permeability. In 1977, Cook and Cunningham described a procedure to analyze the gas leakage potential based on a similar fluid-loss-rate computation. However, Webster and Eikerts (1979) pointed out that, because earlier work was not based upon flow equations, the relative importance of fluid loss may have been overemphasized. The positive influences of the drilling mud filtercake and mud-particle invasion into the formation had been neglected. Baret (1988) confirmed the critical importance of fluid loss by more precise direct computations based on Darcy flow. He determined that, even in the presence of drilling mud filtercake, API fluid-loss rates as low as 10 mL/30 min would sometimes be required to prevent annular bridging.

It is important to mention that poor fluid-loss control across permeable formations further up the hole can also impair full transmission of the hydrostatic pressure to a gas zone. In 1976, Garcia and Clark observed gas migration when fluid loss occurred high in the hole, and hydrostatic pressure was no longer transmitted from the column above the bridging point to the bottom of the hole.

Parcevaux (1987) discussed how fluid loss causes a pore-pressure decline and the formation of a void space in the cement. The interstitial water in cement slurry is mobile; therefore, some degree of fluid loss always occurs when the annular hydrostatic pressure exceeds that of the formation. The process slows when a low-permeability filtercake forms against the formation wall and can stop altogether when the annular and formation pressures equilibrate. Once pressure equilibrium is attained, any volume change within the cement will provoke a sharp pore-pressure decline; consequently, because of the low cement compressibility, a void space forms within the cement matrix, potentially inducing gas influx into the cement.

<table>
<thead>
<tr>
<th>Table 9-1. Factors Responsible for Gas Migration</th>
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<tbody>
<tr>
<td><strong>Annular Pressure ≤ Pore Pressure</strong></td>
</tr>
<tr>
<td>Immediate</td>
</tr>
<tr>
<td>Short term</td>
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<tr>
<td>Gel strength development</td>
</tr>
<tr>
<td>Chemical shrinkage of cement</td>
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<tr>
<td>Annular bridging</td>
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<td>Annular packers</td>
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<tr>
<td>Long term</td>
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<tr>
<td>Gel strength development</td>
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<tr>
<td>Chemical shrinkage of cement</td>
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<tr>
<td>Annular bridging</td>
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<tr>
<td>Annular packers</td>
</tr>
<tr>
<td>Strength development of cement</td>
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<tr>
<td>Bulk shrinkage of cement</td>
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</tbody>
</table>
In 2002, Nishikawa and Wojtanowicz discounted the validity of previously published pressure-decline theories because the correlation with field data was poor. They proposed a different model with the following assumptions. Once the cement is in place in the annulus, fluid is initially lost by filtration driven by a hydrostatic overbalance. The resulting volume change causes pressure reduction owing to the compressibility of the system. As the volume reduction continues, the cement slurry moves downward in plug flow, causing friction drag at the wellbore walls and an annular pressure decrease. This pressure transient effect is transmitted upwards from the zone of fluid loss to the surface as a function of depth and time. A mathematical model was derived for the pressure unloading.

\[ p(h, t) = 0.052 \rho_{eq} h + 2 \sum_{n=1}^{\infty} \frac{0.052}{D_{boc}} (\rho_{s} - \rho_{eq}) \left\{ \frac{(-1)^{n+1}}{\alpha^{n}} \sin(\alpha h)e^{\alpha^{2}t} \right\}, \]  

(9-1)

where

- \( c \) = compressibility (psi\(^{-1}\))
- \( D_{boc} \) = Depth at bottom of cement
- \( h \) = depth (cm)
- \( t \) = time after pumping slurry (min)
- \( \alpha \) = constant defined as

\[ \alpha = \left( n\pi - \frac{\pi}{2} \right) \frac{1}{D_{boc}} \]

\( \rho_{eq} \) = equivalent density of normal formation
\( \rho_{s} \) = density of the cement slurry (lmb/gal).

This model was validated in the field when six pressure gauges were distributed throughout the interval of interest in the annulus of a well. The bottomhole pressures calculated from the model closely matched the pressure reduction in the well (Fig. 9-5).

As shown in Chapter 6, cement filtercakes generally have very low permeability. Bannister et al. (1983) concluded that low-permeability cement filtercake deposition at the point of gas invasion could hinder gas flow. It is important to note that API fluid-loss tests are performed at a fixed differential pressure across a permeable medium. Thus, according to Darcy’s law, the same fluid-loss rate could be measured for two very different slurries: one with a relatively thin, low-permeability filtercake, and another with a relatively thick, high-permeability filtercake. From the preceding discussion, it is clear that low-fluid-loss cement systems that form thin, low-permeability filtercakes are more effective at controlling gas migration.

9.3.3.2 Gel strength development

As early as 1970, Carter and Slagle noticed that thixotropy or gelation of wellbore fluids was relevant to the reduction of hydrostatic pressure but provided no explanation. Experiments to quantify the effect of gelation on hydrostatic pressure transmission gave inconclusive results (Carter et al., 1973). Some pressure restriction was observed at low curing pressures, but experiments at greater pressures (500 to 1,000 psi or 3.5 to 7 MPa) indicated no pressure change. This was probably related to deficiencies in the experimental design.

It is interesting to note that, much earlier, hydrostatic pressure reduction during cement hydration had been demonstrated in the laboratory and confirmed by field measurements (Guyvoronsky and Farukshin, 1963; Vidovskii et al., 1971) in the former Soviet Union. Similar field measurements were performed later by Cooke et al. (1982), in which the use of external casing sensors permitted the observation of downhole temperature and pressure fluctuations as well as the transmission of applied surface pressure (Fig. 9-6). From this information, it was possible to derive the extent of vertical fluid movement into the wellbore, locate the top of the cement column, and measure the cement setting time at different depths.
In 1982, Sabins et al. related the kinetics of hydrostatic pressure reduction to the cement-slurry gel strength development, fluid-loss volume, volume reduction owing to hydration, and slurry compressibility factor. This work resulted in an empirical method to predict gas migration, and the following equation was derived.

$$\Delta p = \left( \frac{4 \times S_{\text{gel}} \times L}{d_{\text{hole}} - d_{\text{pipe}}} \right) \text{ or } \left( \frac{\Delta V_{f} + \Delta V_{\text{hyd}}}{f_{c}} \right),$$  \hspace{1cm} (9-2)

where

- $d_{\text{hole}}$ = hole diameter (m)
- $d_{\text{pipe}}$ = pipe diameter (m)
- $f_{c}$ = slurry compressibility factor (dimensionless)
- $L$ = cement column length (m)
- $\Delta p$ = hydrostatic pressure change (kPa)
- $S_{\text{gel}}$ = static gel strength (Pa)
- $\Delta V_{f}$ = fluid-loss volume reduction (L)
- $\Delta V_{\text{hyd}}$ = hydration volume reduction (L).

In 1979, Tinsley et al. introduced the concept of transition state, an intermediate period during which the cement behaves neither as a fluid nor as a solid and the slurry loses its ability to transmit hydrostatic pressure. The concept of transition state was quantified by a transition time, beginning with the first measurable gel strength (about 21 lbf/100 ft² [10 Pa]), and ending when gas could no longer percolate within the gelled cement. They showed that a gel strength range from 250 to 500 lbf/100 ft² [120 to 240 Pa] was sufficient to prohibit gas percolation. Gas percolation can be considered a particular type of gas migration in which gas in the form of macroscopic bubbles invades the slurry and rises owing to buoyancy effects in accordance with Stokes law. Cement slurries behave as non-Newtonian fluids; therefore, this process involves the breakage of the slurry’s gel strength. However, gas may also flow at the microscopic level within the pores of the gelled cement structure (Section 9-3.3.4) or directly along the cement/pipe and cement/formation interfaces (Section 9-3.3.7). Any or all of these processes may contribute to the overall phenomenon of gas migration, and this limits the applicability of Eq. 9-2.

Grachyov and Leonov (1969), Parcevaux (1987), and Drecq and Parcevaux (1988) further formalized the pressure-reduction process by taking advantage of the similarities between a gelling cement column and a layer of soil undergoing consolidation. Using the theory of soil mechanics and assuming that the cement slurry behaves as a virgin sedimentary soil before significant hydration occurs, the state of stress in the slurry can be described by Terzaghi’s law (Vyalov, 1986). Either U.S. or SI units may be used in the following two equations, as long as the unit system is consistent.

$$\sigma = \sigma' + p,$$  \hspace{1cm} (9-3)

where

- $p$ = interstitial (pore) or hydrostatic pressure
- $\sigma$ = total stress exerted at a given linear depth, $z$
- $\sigma'$ = intergranular or effective stress related to gel-strength development.

$\sigma$ is constant and equal to the full overburden pressure exerted by the fluid column.

$$\sigma = g \int_{0}^{D} \rho_{\text{slurry}}(z) \cos \theta(z) dx,$$  \hspace{1cm} (9-4)

where

- $D$ = total linear depth
- $g$ = gravitational coefficient
- $\theta$ = angular deviation
- $\rho_{\text{slurry}}$ = specific gravity of the slurry at depth $z$.

The effective shear stress, $\sigma'$, is related to the static gel strength determined in the laboratory, using the method described by Sabins et al. (1982) or by Hannant and Keating (1985), which incorporates the classic shear-stress equation.

$$\sigma' = \frac{4 \times L \times S_{\text{gel}}}{d_{\text{hole}} - d_{\text{pipe}}},$$  \hspace{1cm} (9-5)

where

- $d_{\text{hole}} - d_{\text{pipe}}$ = width of the annular gap (m)
- $L$ = length (m)
- $S_{\text{gel}}$ = static gel strength (Pa)
- $\sigma'$ = shear stress (Pa).
Equations 9-4 and 9-5 can thus be combined to obtain

\[ p = \sigma - \sigma' = \rho_{\text{slurry}} g D \cos \theta - \frac{4 \times L \times S_{\text{gel}}}{d_{\text{hole}} - d_{\text{pipe}}}. \]  

(9-6)

The hydrostatic pressure, \( p \), exerted by the slurry in front of the formation varies as a function of the static gel strength, \( \sigma' \). However, the exact value of \( p \) at time \( t \) may be different from that given by Eq. 9-6 because of kinetic effects.

When gelation occurs during the induction or dormant period, there is no significant hydration of the cement grains but essentially a buildup of intergranular forces owing to interparticle electrostatic forces and the precipitation of hydrates (Chapter 2). In a first approximation, the total stress, \( \sigma \), remains the same, but a transfer from \( p \) to \( \sigma' \) occurs. Eventually, \( \sigma' \) increases to a point at which the cement becomes self-supporting. At this time, the interstitial pressure drops to that of a column of water, as shown by Eqs. 9-7 and 9-8.

\[ p = \rho_{\text{slurry}} g D \cos \theta \]  

(9-7)

\[ \sigma' = (\rho_{\text{slurry}} - \rho_{w}) g D \cos \theta \]  

(9-8)

where

\[ \rho_{w} = \text{the specific gravity of the interstitial water.} \]

### 9.3.3.3 Cement shrinkage

Cement shrinkage contributes to gas migration by causing an annular-pressure reduction and by providing space for gas to enter the wellbore. When cement enters the setting period and hydration accelerates, intergranular stresses increase above the value given in Eq. 9-8 because of the intergrowth of calcium silicate hydrates. Were no volume change to occur at this stage, the pore pressure would remain at the level given by Eqs. 9-7 and 9-8, and the cement would behave as a porous formation. However, this is not the case. Cement hydration is responsible for an absolute volume reduction of the cement matrix, also called cement chemical contraction, which was first identified by LeChâtelier in 1887 (Chapter 2; Appendix B). He showed, for normal Portland cement, a volumetric shrinkage of 4.6%. This shrinkage is well documented in the civil engineering literature (Setter and Roy, 1978) and occurs because the volume of the hydrated phases is less than that of the initial reactants.

Powers studied the shrinkage of pure cement phases as early as 1935 and found it to increase along the series \( \text{C}_2\text{S}-\text{C}_3\text{S}-\text{C}_4\text{AF}-\text{C}_3\text{A} \) from 1% for \( \text{C}_2\text{S} \) up to 16% for \( \text{C}_3\text{A} \). He found that the absolute shrinkage of Portland cement pastes varies between 2.3% and 5.1%, according to the following equation.

\[ \Delta V_{\text{ab}} = K_{\text{hyd}1} [\text{C}_3\text{S}] + K_{\text{hyd}2} [\text{C}_2\text{S}] + K_{\text{hyd}3} [\text{C}_3\text{A}] + K_{\text{hyd}4} [\text{C}_4\text{AF}] \]  

(9-9)

Powers assumed that, for each type of cement, the shrinkage is a linear function of the percentages of the four major clinker phases. The values \( K_{\text{hyd}1}, K_{\text{hyd}2}, K_{\text{hyd}3}, \) and \( K_{\text{hyd}4} \) are coefficients with values varying with the age (degree of hydration) of the specimen.

In 1982, Geiker and Knudsen found the rate and magnitude of the chemical shrinkage to increase slightly with the water-to-cement ratio but the ultimate degree of shrinkage to decrease with increasing curing temperature. The total chemical contraction is split between a bulk or external volumetric shrinkage, less than 1%, and a matrix internal contraction representing from 4% to 6% by volume of cement slurry, depending upon the cement composition (Parcevaux and Sault, 1984). Thus, when considering cement shrinkage, a distinction should always be made between the two types. In most cases, data reported in the literature refer to total chemical contraction.

Shrinkage values of less than 4% were reported by Chenevert and Shreshtha (1987); however, their experimental design suggests that the phenomenon measured was not the total chemical contraction, but a combination of bulk shrinkage and reabsorption of cement free water. Chemical contraction is a time-dependent phenomenon (Fig. 9-7) that begins during the initial setting and levels off after the final set (Stewart and Schouten, 1986).

In 1979, Levine et al. made a significant contribution by relating shrinkage to pressure reduction. They measured the hydrostatic pressure transmission of cement slurries in a 47-ft long cell with no external pressure source (Fig. 9-8). They demonstrated that the hydrostatic pressure gradient gradually decreases to that of the mix water. Later, when the cement slurry begins to set, the hydrostatic pressure quickly approaches zero (Fig. 9-9). The hydrostatic pressure reduction is the result of shrinkage within the cement matrix caused by hydration and fluid loss; at this point, the fluid column above cannot reestablish the pore pressure.
Fig. 9-7. Typical contraction and shrinkage (from Parcevaux, 1987). Temperature is 10°C.

Fig. 9-8. Schematic diagram of apparatus to measure hydrostatic pressure transmission of cement slurries (from Levine et al., 1979). Reprinted with permission of SPE.

Fig. 9-9. Annular gas flow test results (from Levine et al., 1979). Reprinted with permission of SPE.
Chemical contraction is also responsible for a secondary porosity, mainly composed of free and conductive pores (Parcevaux, 1984b). At the same time, interstitial water is trapped within the pores through physicochemical and capillary forces and can no longer move when submitted only to its own hydrostatic pressure gradient. The combination of chemical shrinkage and secondary porosity is responsible for the sharp cement pore-pressure decrease from the water gradient to the formation pressure, or even to less than the atmospheric pressure if the system is isolated. This was observed by Levine et al. (1979) and described by Stewart and Schouten (1986).

Contrary to earlier work, Nishikawa and Wojtanowicz (2002) reasoned that chemical shrinkage was not responsible for annular pressure reduction. Their conclusion was based on experiments involving a solid steel rod suspended in a cylindrical container filled with cement. The weight of the rod was continuously measured as the cement was setting. The theory behind the experiment was that cement shrinkage would instigate a downward movement of the cement column while gelation would increase the friction at the surface of the rod. Therefore, if gelation and shrinkage occurred concurrently, the rod would be pulled down by friction, causing the measured weight of the rod to increase over time. In the experiments, they did observe a drop in the level of the cement column; however, they recorded no weight change, leading them to the conclusion that chemical shrinkage does not contribute to annular pressure decline. This experiment did not take into account the reduction in pore pressure that would have occurred in the cement slurry, which would have had an offsetting effect on the frictional forces. The experimental setup may also not have had sufficient hydrostatic overburden to cause a significant degree of compaction.

9-3.3.4 Permeability

The concept of gas migration through the pore structure of a very permeable gelled or set cement, as well as the potential gas percolation within the gelling slurry that can occur beforehand, was first introduced by Guyvoronsky and Farukshin (1963). During the period of hydrostatic pressure reduction, the cement matrix permeability was measured to be as high as 300 mD. In 1982, Cheung and Beirute proposed a gas migration mechanism, based on laboratory experiments, by which the gas first invades cement pore spaces and eventually permeates the entire cement matrix; consequently, the hydration process is prevented from closing the pore spaces. Parcevaux (1984b) further refined this mechanism by studying the pore-size distribution of cement slurries during thickening and setting. He demonstrated the existence of free porosity composed of well-connected pores that begin to appear upon the initiation of the setting period. The same author went on to confirm that gas migration is driven by an unsteady permeability effect through the cement pores. After an initial enlargement of the cement pores, a pseudo-steady state is achieved when communication has been established throughout the cement column and gas channels have reached a stable size.

In 1986, Stewart and Schouten confirmed and expanded upon the earlier results of Levine et al. (1979). They concluded that, when a stable cement slurry (i.e., featuring negligible particle settling) enters the transition state, it begins to gel, and the hydrostatic pressure decreases ultimately to that of its water phase. When initial setting commences, this pressure (now a pore pressure) decreases further. In the same paper, Stewart and Schouten questioned the validity of chemical shrinkage for describing the potential pressure restriction in Eq. 9-1, arguing that this equation assumes the slurry acts as a coherent “one-phase body.” Such an assumption is valid for pumping applications but not for cases in which the slurry is depressurized internally by fluid loss or hydration.

9-3.3.5 Free fluid (free water)

The effect of cement-free-water separation was studied and discussed by Tinsley et al. (1979) and Webster and Eikerts (1979). The former concluded through pilot-scale experiments that, although undesirable, free water is not an influential factor with respect to annular gas flow. The latter group studied the problem by constructing a 9-ft long acrylic model, inclined up to 70° and connected to a gas entry source and several pressure sensors (Fig. 9-10). They observed that, in deviated holes, the free water could coalesce to form a continuous channel on the upper side of the hole, forming a privileged path by which the gas may migrate. Thus, they recommended cement slurries that develop essentially no free water.

Despite their observations in the laboratory-scale model, Webster and Eikerts were unable to establish a clear relationship between the angle of deviation and the importance of the water channel. The nomenclature for this laboratory test was changed from free water to free fluid in the 1997 edition of API Recommended Practice (RP) 10B, Recommended Practice for Testing Well Cements (Appendix B). The new procedure prescribes cement-slurry conditioning in a pressurized consistometer at bottomhole circulating temperature before placement in a tube tilted at the same angle as the hole. Webster and Eikerts (1979) and Bergeron and Grant (1989) recommended that testing be performed at a 45° angle, the most severe test condition.
9-3.3.6 Mud removal

Early work attributed gas migration problems to poor mud removal, poor cement/casing or cement/formation bonding, or both (Carter and Evans, 1964; Carter and Slagle, 1970). While several other important contributing factors have since been identified, effective mud removal is still recognized as imperative for controlling annular gas migration. The importance of effective mud removal in controlling gas migration cannot be underestimated because, regardless of the properties of the cement placed in the annulus, a continuous mud channel between two permeable zones will favor fluid migration. A detailed discussion on the fundamentals of mud displacement mechanics and guidelines can be found in Chapter 5.

9-3.3.7 Microannulus

Another path for gas to migrate is through a microannulus—a gap that may form between the cement sheath and the casing or the formation after the cement has set. A microannulus is a common occurrence that can result from any number of events during the life of a well. It has long been known that a pressure decrease inside the wellbore after the cement has set will result in a casing-diameter reduction, leading to the formation of a microannulus. This commonly occurs when the density of fluid inside of the casing is reduced after the cement job. A wellbore-temperature decrease will also reduce the casing diameter.

An example of a situation in which both pressure and temperature reduction can occur is when the casing is closed in at the end of the cement job. The exotherm generated by cement hydration will cause thermal expansion of the steel casing. In addition, fluids trapped inside the casing will heat up, causing further thermal expansion of the casing. Later, when the casing is opened after the cement has set, the pressure inside the casing will drop. The heat generated by cement hydration will also eventually dissipate. Consequently, the casing diameter will return to its original size.

Finally, a bulk volume reduction of the cement sheath owing to chemical shrinkage may result in a microannulus. However, laboratory measurements have shown this to be negligible under conditions normally encountered in a cemented annulus (Baumgarte et al., 1999).

9-3.3.8 Cement sheath mechanical failure

Cracking of the cement sheath caused by imposed tensile stresses, compressional stresses, or both (Fig. 9-11) can form a gas migration path in the annulus. Wellbore stresses that may be responsible for cement sheath failure can result from changes in wellbore temperature and pressure, tectonic stresses, subsidence, and formation creep. The relative strength of the formation behind the cement sheath is known to have an impact on determining whether a given cement sheath will fail when exposed to wellbore stresses. Formations that are hard, as characterized by a high Young's modulus, will confine the cement sheath and make it less susceptible to cracking. Formations that are relatively soft, as characterized by a low Young's modulus, will not provide sufficient confinement to prevent cracking. A more detailed discussion on cement sheath mechanical failure is presented in Chapter 8.

9-4 Predicting short-term gas migration

Gas migration is a complex physical phenomenon that comprises many facets; as a result, physical modeling of this phenomenon is a formidable problem. It is a non-steady-state process involving changing pressure fields and fluid saturations, and an evolving matrix structure.
Heterogeneities within the cement slurry, or boundary effects at the casing or formation, can induce singular events (such as nonuniform gas breakthrough) that are, by definition, unpredictable. Therefore, it is impossible to predict the occurrence of gas migration, nor its definitive solution, on an absolute basis. Various prediction approaches have been developed, but none is universally applicable. The most common approach to prediction is a systematic well analysis, resulting in a purely qualitative risk assignment.

9-4.1 Gas flow potential

Sutton et al. (1984) described one of the first systematic approaches to gas migration prediction by calculating a relative gas flow potential (GFP). The GFP is the ratio of the maximum pressure restriction (MPR) to the hydrostatic overbalance pressure of the well.

\[ K_{gfp} = \frac{K_{mpr}}{p_{ob}} \]  

(9-10)

MPR is further defined as

\[ K_{mpr} = 1.67 \left( \frac{L}{d_{hole} - d_{pipe}} \right) \]  

(9-11)

where

- \( d_{hole} \) = diameter of the open hole (in.)
- \( d_{pipe} \) = diameter of the pipe (in.)
- \( K_{gfp} \) = gas flow potential
- \( K_{mpr} \) = maximum pressure restriction
- \( L \) = cement column length (ft)
- \( p_{ob} \) = overbalance pressure (psi).

The GFP is a dimensionless number that can vary between 0 and infinity, and the severity of the potential gas migration problem is rated according to Table 9-2.

<table>
<thead>
<tr>
<th>GFP</th>
<th>Severity Rating</th>
</tr>
</thead>
<tbody>
<tr>
<td>&lt;4</td>
<td>Minor</td>
</tr>
<tr>
<td>4–8</td>
<td>Moderate</td>
</tr>
<tr>
<td>&gt;8</td>
<td>Severe</td>
</tr>
</tbody>
</table>

9-4.2 Expanding the factors for gas flow potential

Later, a more detailed method developed by Rae et al. (1989) focused on four factors whose components are considered fundamental to the occurrence of gas migration.

1. Formation
2. Hydrostatic pressures in the wellbore
3. Mud removal efficiency
4. Slurry performance

The calculations are based on reservoir deliverability, annular geometry, gas-zone pore pressure, hydrostatic pressure, mud removal efficiency, cement hydration kinetics, and fluid-loss control.

The Rae et al. (1989) method was not based on a single experimental investigation or on numerical simulations; instead, it was a pragmatic compilation of the state of the art at the time it was developed. A statistical analysis of data from a wide variety of gas wells in the United States, Canada, Latin America, Europe, Africa, the Middle East, and the Far East allowed the calculation of semiempirical relationships between the four factors. Rae et al. claimed that the wide range of field conditions covered by their method justified its use in most real cases.

9-4.2.1 Formation factor

The first factor, the formation factor, is a dimensionless ratio of the reservoir’s productive capacity, \( kh \), to the critical volume, \( V_{crit} \) (Eq. 9-12). The critical volume is the additional cement porosity that is created during setting by chemical shrinkage between the top of the gas zone and the pressure balance point. A slurry porosity of 2% is assumed at this stage of hydration, and gas is assumed to permeate the annulus in a uniform fashion over the defined length. Assuming all other factors remain constant, as the value of the formation factor increases, the risk of gas migration increases.

\[ f_{form} = \frac{kh}{V_{crit}} = \frac{467.7kh\rho_{slurry}}{p_{ob}\left[(d_{hole})^2 - (d_{pipe})^2\right]^2} \]  

(9-12)

where

- \( d_{hole} \) = hole diameter (in.)
- \( d_{pipe} \) = pipe diameter (in.)
- \( h \) = zone height (ft)
- \( k \) = zone permeability (mD)
- \( p_{ob} \) = overbalance pressure (psi)
- \( \rho_{slurry} \) = cement-slurry density (lbm/gal).
9-4.2.2 Hydrostatic factor

The hydrostatic factor (HF) stems from the work of Levine et al. (1979), who observed that the hydrostatic pressure exerted by cement slurries decreases, approaching that of the interstitial water as gel strength increases. They assumed that further pressure decay occurs only after the cement has set. In theory, when cementing to the surface, gas zones with pore pressures greater than the hydrostatic pressure of water can flow as soon as the cement gels. When a mud column remains above the cement, this must be taken into account as an additional hydrostatic pressure source that is summed with that of the cement interstitial water. Thus, the hydrostatic factor is represented by the ratio of the gas-zone pore pressure to that of the annular pressure at the commencement of the initial set (Eq. 9-13). Again, greater values of the hydrostatic factor indicate a increased risk of gas migration in a given well situation.

\[
f_{\text{hyd}} = 19.281 \frac{p_{\text{gas}}}{\left( \rho_{\text{mud}} \times h_{\text{mud}} \right) + \left( \rho_{\text{sp}} \times h_{\text{sp}} \right) + \left( 8.32 \times h_{\text{cem}} \right)},
\]

where

- \( f_{\text{hyd}} \) = hydrostatic factor
- \( h_{\text{cem}} \) = height of cement in the annulus (ft)
- \( h_{\text{mud}} \) = height of mud in the annulus (ft)
- \( h_{\text{sp}} \) = height of spacer in the annulus (ft)
- \( p_{\text{gas}} \) = gas zone pressure (psi)
- \( \rho_{\text{mud}} \) = mud density (lbm/gal)
- \( \rho_{\text{sp}} \) = spacer density (lbm/gal).

9-4.2.3 Mud removal factor

The mud removal factor (MRF) described by Rae et al. (1989) was a subjective scale from 1 to 10, based upon how closely a defined set of industry standards for mud removal (Table 9-3) were followed. More quantifiable means of predicting mud removal have since been developed (Chapter 5) that supersede these qualitative standards. Consequently, the MRF has been largely superseded by more sophisticated methods that are described later.

9-4.2.4 Slurry performance number

The final factor considered by Rae et al. (1989) was the slurry performance number (SPN), which was developed to rank cement systems according to their hydration kinetics and fluid-loss control. It is based on an approximation of the interstitial water lost as the cement undergoes the initial hydration process, which is calculated from the results of standard API laboratory fluid-loss and thickening time tests.

\[
N_{sp} = q_{API} \left( \sqrt{t_{100Bc}} - \sqrt{t_{30Bc}} \right),
\]

where

- \( N_{sp} \) = slurry performance number
- \( q_{API} \) = API fluid-loss value of slurry (mL/30 min)
- \( t_{30Bc} \) = time to 30 Bearden units of consistency (min)
- \( t_{100Bc} \) = time to 100 Bearden units of consistency (min).

The term

\[
\sqrt{t_{100Bc}} - \sqrt{t_{30Bc}}
\]

is known as the transition time. It must be emphasized that this equation does not represent the actual performance of the slurries under static downhole conditions in which the mud filtercake influences the leakoff. Instead, the SPN provides a method of comparing slurry performance on a relative basis and provides a useful tool in both the design and evaluation of cement programs for gas wells. Slurries with high SPNs are very poor candidates for gas migration control. Those with low API fluid-loss rates and short critical hydration periods offer a much greater probability of success.

**Table 9.3. Mud Removal Guidelines**

<table>
<thead>
<tr>
<th>Excellent</th>
<th>Moderate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hole in excellent condition before cementing</td>
<td>Hole in excellent condition before cementing</td>
</tr>
<tr>
<td>Circulate one hole volume</td>
<td>Circulate one hole volume</td>
</tr>
<tr>
<td>No gas</td>
<td>Condition mud</td>
</tr>
<tr>
<td>Condition mud</td>
<td></td>
</tr>
<tr>
<td>Greater than 67% standoff</td>
<td>Greater than 50% standoff</td>
</tr>
<tr>
<td>Minimal U-tubing</td>
<td>Minimal U-tubing</td>
</tr>
<tr>
<td>Compatible fluids</td>
<td>Compatible fluids</td>
</tr>
<tr>
<td>Use of washes/spacers</td>
<td>Use of washes/spacers</td>
</tr>
<tr>
<td>Engineered displacement</td>
<td>Engineered displacement</td>
</tr>
<tr>
<td>10-min spacer contact time</td>
<td>10-min spacer contact time</td>
</tr>
<tr>
<td>Use of two bottom plugs</td>
<td>Rotation and reciprocation of pipe</td>
</tr>
<tr>
<td>Rotation and reciprocation of pipe</td>
<td></td>
</tr>
</tbody>
</table>

Chapter 9 Annular Formation Fluid Migration
9-4.3 Recent developments in gas migration prediction

More recently, improvements have been made to the Rae et al. (1989) gas migration prediction approach. These changes involve a more detailed definition of the formation parameter (FP), a more quantitative determination of the mud removal parameter (MRP), and the calculation of a pressure decay limit parameter (PDLP), which replaces the previous HF. Additionally, the new approach does not use an SPN as part of the risk assessment process. Instead, it recommends slurry types that have been qualified through laboratory testing based upon the predicted level of risk from the other three parameters (N. Quisel, unpublished results).

9-4.3.1 Formation parameter

The revised FP is based upon the reservoir’s ability to deliver gas. To estimate the produced gas volume, \( V_{gas} \), across a unit section, the basic steady-state relation for gases is used.

\[
V_{gas} = \frac{\pi kht \left( p_{pore} - p_{ann} \right)^2}{\mu_{gas} \times p_{ann} \ln \frac{r_{res}}{r_{hole}} + s}, \]  

(9-15)

where

- \( h \) = gas zone length (m)
- \( k \) = formation permeability (m²)
- \( p_{ann} \) = annular hydrostatic pressure at top of gas zone (Pa)
- \( p_{pore} \) = pore pressure at top of gas zone (Pa)
- \( r_{hole} \) = hole radius (m)
- \( r_{res} \) = reservoir radius (m)
- \( s \) = dimensionless skin factor (s = 0 by default).
- \( t \) = production time estimated from setting time (sec)
- \( V_{gas} \) = gas volume, downhole conditions (m³)
- \( \mu_{gas} \) = gas viscosity (Pa-s).

The skin factor is highly dependent upon the base fluid of the drilling mud (oil or water). A typical skin value is equal to 20.

The gas viscosity, \( \mu_{gas} \), depends on pressure and temperature conditions. It is given by Eq. 9-16. This particular equation is for methane.

\[
\mu_{gas} = (9.76 \times 10^{-6}) + \left( 0.0126 \times 10^{-6} T \right) + \\
\left \{ p \left[ (3.22 \times 10^{-9}) - (4.84 \times 10^{-12} T) \right] \right \}, \]  

(9-16)

where

- \( p \) = pressure (psi)
- \( T \) = temperature (°F).

One can assume that there is a critical volume of space available for the gas to occupy in the annulus before the gas migration problem becomes serious. This is called the critical annular volume. As previously discussed, this space is created by fluid-loss, shrinkage, and slurry permeability. A conservative assumption is that the available space for gas to occupy is 5% of the total slurry volume above the gas zone. Therefore, the critical annular volume is calculated as 5% of the total slurry volume from the top of the gas-bearing zone to the top of the caprock for that zone.

\[
V_{crit} = \frac{0.05 \pi \left( d_{hole}^2 - d_{pipe}^2 \right) L}{4}, \]  

(9-17)

where

- \( d_{hole} \) = hole diameter (m)
- \( d_{pipe} \) = pipe diameter (m)
- \( L \) = length from top of gas zone to top of caprock (m)
- \( V_{crit} \) = critical annular volume
- 0.05 = the coefficient for space available gas in the slurry.

The FP can then be calculated from the ratio of the produced gas volume to this critical annular volume by combining Eq. 9-15 and Eq. 9-17.

\[
K_{fp} = \frac{V_{gas}}{V_{crit}} \]  

\[
= \frac{80kht \left( p_{pore} - p_{ann} \right)^2}{\left( d_{hole}^2 - d_{pipe}^2 \right) L \mu_{gas} \times p_{ann} \ln \frac{r_{res}}{r_{hole}} + s}, \]  

(9-18)

where

- \( K_{fp} \) = formation parameter.

Various levels of severity may then be empirically assigned to the value of the FP (Table 9-4).
9-4.3.2 Mud removal parameter

The second parameter is the MRP. With the advent of improved two-dimensional mathematical simulators for fluid displacement (Chapter 5), the ability to quantify the effectiveness of mud removal has advanced significantly in recent years. As shown in Fig. 9-12, such a mathematical simulator can be used to calculate cement concentration on a mesh grid representing a wellbore. Perfect displacement would be predicted if a cement concentration value of 100% were indicated across the entire length.

Using industry-accepted practices that have been developed from field experience, positive zonal isolation will usually be achieved with 500 ft of cement coverage above the top of the gas-bearing zone. An MRP can thus be calculated over this zone.

\[ K_{mrp} = \frac{1}{h} \int_{D_{bg}}^{D_{bg}+500\text{ft}} (Y_{cc}) \, dz, \tag{9-19} \]

where

- \( D_{bg} \) = Depth to bottom of gas zone
- \( D_{bg} \) = Depth to top of gas zone
- \( h \) = length from bottom of gas zone to 500 ft above top of gas zone
- \( K_{mrp} \) = mud removal parameter
- \( Y_{cc} \) = cement concentration value (calculated by mathematical simulator).

Although the MRP is a useful design tool, one should not forget the importance of the good cementing practices outlined in Chapter 5.

9-4.3.3 Pressure decay limit parameter

The third parameter is the PDLP, which is based upon the concept of critical wall shear stress described by Stiles (1997). When a fluid is placed inside a pipe or annulus, a shear stress may be created along the wall, causing the annular pressure to drop below the hydrostatic pressure. However, the fluid column has lower pressure limits at all depths along the wellbore:

- pressure applied at the top of the annulus (normally atmospheric pressure)
- pore pressure in front of permeable zones
- vapor pressure of water in front of impermeable zones (including casing-in-casing annuli).

The pressure cannot drop below these limits at any depth. Gas migration can occur only when the annular pressure at a given depth drops to a value equal to or less than the pore pressure of a gas-bearing zone at that depth. The shear stress at the wellbore wall that causes the pressure to reach this critical value for gas entry is the PDLP. The following equation uses oilfield units.

\[ K_{pdlp} = P_{ob} \left( \frac{d_{kole} - d_{pipe}}{4L} \right), \tag{9-20} \]

where

- \( K_{pdlp} \) = pressure decay limit parameter
- \( L \) = the length of the cement column above the gas-bearing formation
- \( p_{ob} \) = overbalance pressure at the end of cement placement, further defined as
  \[ p_{ob} = p_{mud} + p_{sp} + p_{cem} + p_{back} - p_{pore}, \tag{9-21} \]
  where
  - \( p_{back} \) = backpressure (i.e., atmospheric pressure + any applied backpressure)
  - \( p_{cem} \) = hydrostatic pressure from the cement column
  - \( p_{mud} \) = hydrostatic pressure from the mud column

Table 9-4. Severity Ratings Versus FP

<table>
<thead>
<tr>
<th>FP</th>
<th>Severity Rating</th>
</tr>
</thead>
<tbody>
<tr>
<td>&gt;1</td>
<td>Very critical</td>
</tr>
<tr>
<td>&gt;0.75 to 1</td>
<td>Critical</td>
</tr>
<tr>
<td>&gt;0.5 to 0.75</td>
<td>High</td>
</tr>
<tr>
<td>&gt;0.25 to 0.5</td>
<td>Moderate</td>
</tr>
<tr>
<td>0 to 0.25</td>
<td>Low</td>
</tr>
</tbody>
</table>

Fig. 9-12. Mathematical simulator for the MRP determination.
$p_{pore}$ = pore pressure of the gas-bearing formation

$p_{sp}$ = hydrostatic pressure from the spacer/wash column.

Various levels of severity may be empirically assigned to the value of the PDLP (Table 9-5).

It is very important to note that, by definition, the PDLP is a function of density only. Other slurry properties do not apply. The PDLP is entirely defined by the size of the annular gap, the hydrostatic contributions of the fluids in the well, the length of the fluid column, and the relevant pressure boundaries. Therefore, the only change in slurry design that will affect the PDLP is density.

<table>
<thead>
<tr>
<th>PDLP</th>
<th>Severity Rating</th>
</tr>
</thead>
<tbody>
<tr>
<td>0–25 Pa (0–50 lbf/100 ft²)</td>
<td>Very critical</td>
</tr>
<tr>
<td>25–75 Pa (50–150 lbf/100 ft²)</td>
<td>Critical</td>
</tr>
<tr>
<td>75–150 Pa (150–300 lbf/100 ft²)</td>
<td>High</td>
</tr>
<tr>
<td>150–250 Pa (300–500 lbf/100 ft²)</td>
<td>Moderate</td>
</tr>
<tr>
<td>&gt;250 Pa (&gt;500 lbf/100 ft²)</td>
<td>Low</td>
</tr>
</tbody>
</table>

9-5 Theoretical strategies for combating short-term gas migration

Theoretically, the root causes for gas migration (described in Section 9-3.1) can be combated by managing the annular pressure decline, reducing the space for entry, and minimizing the path for migration. For short-term gas migration, these strategies must be addressed during the postplacement period.

One concept for evaluating the postplacement period is to plot the evolution of gel strength over time (Stiles, 1997). Because gel strength development tends to be logarithmic, the log of gel strength can be plotted as a straight line versus time (Fig. 9-13). The PDLP can be calculated from Eq. 9-20 and plotted on the gel strength graph so that the intersection of this value with the gel strength curve will define a critical time, $t_c$, when gas can first enter the annulus. An upper time boundary, $t_f$, represents the time beyond which the gel strength is too high to allow gas migration. This occurs after the cement begins to set and become an impermeable matrix. $t_f$ is plotted in the same manner as $t_c$, by drawing a vertical line from the x-axis to the gel strength–development/impermeable-matrix gel strength intersection. The time between $t_c$ and $t_f$ is the critical hydration period (CHP).

Stiles recognized three distinct strategies for shortening the CHP and thus reducing the risk of gas migration.

- Reduce the matrix permeability of the cement.
- Increase the rate of gel strength development.
- Increase the PDLP.

Decreasing the upper boundary limit can be achieved by reducing the matrix permeability of the cement (Fig. 9-14). This is accomplished by altering the cement-slurry design, for example by adding small-particle constituents. However, because the y-axis is logarithmic, it is apparent that a relatively large decrease in matrix permeability will result in a relatively small decrease in the CHP.

Increasing the slope of the gel strength–development curve has a major effect on the CHP (Fig. 9-15). This can also be accomplished by modifying the cement-slurry design.
Finally, the CHP can be shortened significantly by increasing the PDLP (Fig. 9-16). By reviewing Eq. 9-20, which defines the PDLP, it can be seen that, unlike the previous strategies, the PDLP cannot be affected by modifying any of the cement-slurry properties (with the exception of the density). Instead, the size of the annular gap, the hydrostatic contributions of the fluids in the well, the length of the fluid column, and the relevant pressure boundaries control this parameter. Increasing the size of the annular gap by decreasing the pipe size or increasing the openhole diameter is one way to increase the PDLP. Incidentally, this would also result in a reduction of the FP (Eq. 9-18), further reducing the potential for gas migration. In most cases, however, neither decreasing the casing diameter nor increasing the openhole diameter would be considered economically viable options for managing gas migration.

Increasing the overbalance pressure (Eq. 9-21) would also increase the PDLP. This could be achieved by increasing the density of any of the wellbore fluids or by increasing the length of a relatively higher-density fluid in the annulus. The overbalance pressure is also increased if backpressure is applied. It is important to remember that setting an annular packer will have the opposite effect. The packer will reduce the overbalance pressure and drastically reduce the PDLP. The final way to improve the PDLP is to decrease the length of the cement column; however, this would not be desirable because the effective length of the annular seal above the gas zone would be shorter.

9-6 Practical solutions for combating gas migration

Practical strategies for combating gas migration can be classified according to the factors previously outlined in Table 9-1. Table 9-6 presents the strategies as a function of the three critical root causes and the three time-based categories for gas migration.

9-6.1 Physical techniques

It has long been known that a number of physical techniques can, under certain circumstances, help control gas migration. These include applying annular backpressure or small pressure pulses to the annulus, using external casing packers (ECPs) and liner-top packers, and reducing the cement column height (including multistage cementing). Such techniques are certainly valid under a variety of conditions, but well conditions often limit their application.

Application of annular backpressure after the cement is in place increases the overbalance pressure exerted on gas zones, thus delaying the time when gas can enter the annulus. However, the presence of weak zones may restrict this technique because of the risk of inducing lost circulation (Levine et al., 1979).

Another technique for delaying gas entry, first described by Haberman and Wolhart in 1997, involves applying pressure pulses to the annulus after the cement is in place. The pressure pulses are applied with compressed air or water at approximately 100 psi at a frequency of 30 to 60 sec/pulse. The concept behind this technique is that the pressure pulses will disrupt gel strength development in the cement and therefore maintain a hydrostatic overbalance for a longer period of time.
Table 9-6. Solutions for Prevention of Gas Migration

<table>
<thead>
<tr>
<th>Root Causes of Gas Migration</th>
<th>Annular Pressure ≤ Pore Pressure</th>
<th>Space for Path for Migration</th>
</tr>
</thead>
<tbody>
<tr>
<td>Immediate</td>
<td>Fluid density na† na</td>
<td>na</td>
</tr>
<tr>
<td>Short term</td>
<td>Right-angle-set cements Low-porosity cements</td>
<td>Packers</td>
</tr>
<tr>
<td>Sandwich squeeze</td>
<td>Low-porosity cements Sandwich squeeze</td>
<td></td>
</tr>
<tr>
<td>Compressible cement</td>
<td>Compressible cement Low-permeability cements</td>
<td></td>
</tr>
<tr>
<td>Fluid density</td>
<td>Compressible cement Surfactants</td>
<td></td>
</tr>
<tr>
<td>Thixotropic cements</td>
<td>Low-fluid-loss cements Thixotropic cements</td>
<td></td>
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<tr>
<td>Low-fluid-loss cements</td>
<td>Low-fluid-loss cements Thixotropic cements</td>
<td></td>
</tr>
<tr>
<td>Back pressure</td>
<td>Zero-free-water cements Low-permeability filtercake</td>
<td></td>
</tr>
<tr>
<td>Annular pressure pulses</td>
<td>Zero-free-water cements Low-permeability filtercake</td>
<td></td>
</tr>
<tr>
<td>Long Term</td>
<td>na na Packers</td>
<td></td>
</tr>
<tr>
<td>na</td>
<td>na Compressible cements</td>
<td></td>
</tr>
<tr>
<td>na</td>
<td>na Expansive cements</td>
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</tr>
<tr>
<td>na</td>
<td>na Flexible cements</td>
<td></td>
</tr>
<tr>
<td>na</td>
<td>na Mud removal</td>
<td></td>
</tr>
</tbody>
</table>

† na = not applicable

ECPs (Fig. 9-17), inflated by mud or cement slurry, control gas migration by forming a positive barrier in the annulus (Suman, 1984). However, ECPs require a competent formation to seal against, and they complicate the job execution. Because of the small clearance between the uninflated ECP element and the borehole, such tools have been known to suffer mechanical damage while casing is being run or during circulation at high rates. Also, it is not uncommon for the packers to set prematurely because of unexpected pressure fluctuations during the course of the job. Parcevaux (1984a) pointed out that ECPs can exacerbate some problems, because they effectively isolate the lower portion of the annulus shortly after cement placement, thus reducing the hydrostatic overbalance across gas zones below the ECP. Slurry volume reduction below the packer, from fluid loss or chemical contraction, can then result in gas invasion of the cement in this interval at an even earlier time. This could permit undesirable crossflow between zones located below the packer.

The technique of reducing the cement column height stems originally from the work of Levine et al. (1979). Viewing the mix-water hydrostatic-pressure gradient as a natural step in the pressure reduction, they proposed minimizing the cement column height above the gas zone using a very simple graphical method (Fig. 9-18). The job would be designed such that the pressure sum of an equivalent height of water plus the hydrostatic pressure above the cement would always exceed the formation pressure. There is little doubt that this approach can help the design process in a gross sense; e.g., severe risks of underbalance may be avoided. It has indeed been applied with success across some depleted sands,
but it is clearly not robust enough. As noted in the same paper, as cement changes from liquid to solid, the hydrostatic pressure falls to values far below that of water because of fluid loss and chemical contraction.

An elastomeric seal ring, described by Bol et al. (1986), presents an additional line of defense for interfacial migration. The success rate may be improved in wells in which downhole stresses, such as density changes or thermal cycling, induce casing deformation. However, it is important to note that this device cannot solve the problem of gas flow through the cement matrix; thus, it should be used in concert with other techniques.

9-6.2 Compressible cements

Compressible cement slurries have been developed to maintain the cement pore pressure above the formation gas pressure. In theory, this should prevent any movement of gas from the formation into the cemented annulus. Compressible cements fall into two main categories: foamed cements and in situ gas generators. It is important to draw a clear distinction between the two.

Foamed cements (Chapter 7) become nearly incompressible at high pressures because of the relative incompressibility of gases under such conditions (Fig. 9-19). Therefore, their ability to compensate for volume reduction during the transition state is probably more effective in situations close to the surface, where gas expansion is more significant. In most cases it is important to maintain the foam quality, or volume of gas contained, below about 30%; otherwise, the permeability of the set cement may be sufficiently high to allow gas migration.

The in situ gas generators are designed to maintain cement pore pressure by virtue of chemical reactions that produce gas downhole. The produced gases may be hydrogen (Bulatov, 1970; Sutton, 1982) or nitrogen (Richardson, 1982; Burkhalter et al., 1984). To the author’s knowledge, the field application of nitrogen to control gas migration has not been reported. Hydrogen-generating agents such as aluminum powder have been used in the former Soviet Union (Kucyn et al., 1977) and elsewhere (Tinsley et al., 1979; Watters and Sabins, 1980). It is important to note that the gas-generating agents alone cannot prevent gas migration. Fluid-loss control agents and dispersants are necessary to minimize interstitial water leakoff.

The principal drawback of these systems, other than the potential safety hazard from those that generate hydrogen, is the inability of a gas at typical downhole pressures to achieve the 4% to 6% volumetric expansion necessary to maintain pore pressure. Strictly applying Boyle’s law, the volume of gas required to offset just the chemical contraction would be excessive at high pressure. Gas-generating systems must also be carefully stabilized; otherwise, gas bubbles may coalesce and create channels for formation gas to follow. These limitations notwithstanding, it is clear that this technology has been used with success.

Fig. 9-18. Comparison of cement column height adjustments (from Levine et al., 1979). Reprinted with permission of SPE.

Fig. 9-19. Compression of foamed cement slurries. $f_{gas}$ is the volumetric fraction of gas in the slurry at surface conditions.
9-6.3 Low-permeability cement slurries

Reducing the matrix permeability of a cement system during the critical liquid-to-solid transition time described earlier can prevent gas migration. Several methods have been developed.

The first approach involved the use of water-soluble polymers to viscosify the interstitial water of the cement slurry. Because at least a part of gas migration involves the displacement of cement pore water, viscosification of the water tends to limit gas mobility. This approach is also appropriate for fluid-loss control; unfortunately, viscosification of the cement slurry is a major side effect of this technique, with resultant mixing difficulties, greater displacement pressures, and increased risk to weak formations.

Cheung and Beirute (1982) described the use of low-permeability cement that operates by immobilizing the fluids within the pore spaces of the cement. Because the cement mix water cannot be displaced, gas cannot move within the pore spaces of the cement slurry. According to Williams et al. (1983), the system is composed of a combination of bridging agents and polymers. Such systems have been applied throughout the 140°F to 350°F [60°C to 180°C] bottomhole static temperature range (Cheung and Myrick, 1983).

Latex additives to prevent gas migration were first described in a 1982 patent application by Parcevaux et al. (issued 1985). Subsequent refinements of this technology (Bannister et al., 1983; Parcevaux and Sault, 1984) have extended its applicability to a wide range of well conditions, and its field application is well established (Evans, 1984; Peralta, 1984; Matthews and Copeland, 1986; Rae, 1987; Drecq and Parcevaux, 1988).

Latex additives are aqueous dispersions of solid polymer particles, including surfactants and protective colloids, which impart stability to the dispersion. Most latexes have film-forming capabilities; thus, when contacted by a gas, or when the particle concentration exceeds a given threshold value, latex particles coalesce to form an impermeable polymer barrier. In a wellbore, the gas first invades the portion of the cemented annulus across the gas zone and contacts the dispersed latex particles in the slurry. As shown in Fig. 9-20, the latex coalesces within the pore spaces, blocking further progress up the annulus.

Blomberg et al. (1986) described another technique that uses fine mineral particulates to prepare low-density, low-permeability cements. The preferred particulate in this application is silica fume (also called microsilica), a byproduct of the production of silicon and ferrosilicon. The average particle size of this material is 1 μm; consequently, it is able to fill pore spaces and plug pore throats. Field success has been reported (Grinrod et al., 1988) for shallow, low-pressure gas.

In the late 1990s (Al-Buraik et al., 1998; Moulin, 2001), new polymeric microgels were developed to control gas migration at temperatures less than 160°F [71°C], at which latexes were not totally effective. The gas migration control is primarily attributed to the ability of the microgels to rapidly plug pore throats in the cement filtercake, forming an impermeable barrier across the gas zone. Gas migration control is also attributed to the fact that the microgels are smaller and less dense than cement particles, and they help to reduce pore-throat continuity (and therefore permeability) in the cement matrix. As a solid structure develops in the setting cement, the smaller pore throats reduce the size of the gas bubbles that can enter the cement, slowing their subsequent migration.

Designing cement systems with a multimodal particle-size distribution can result in cement slurries with considerably less porosity and permeability than a conventional system. The concept, first described by Moulin et al. (1997), is based upon maximizing the particle volume fraction in the dry blend by using three or more distinct particle sizes. This leads to an increased solids content in the cement slurry and thus a reduced porosity and permeability. More information on cements with an engineered particle size distribution can be found in Chapter 7.
9-6.4 Fluid loss and free-fluid control
Fluid loss and free fluid, discussed previously in Sections 9-3.3.1 and 9-3.3.5, promote the occurrence of gas migration. To minimize the effect of these parameters, both must be reduced to fairly low levels. Fluid-loss rates of 50 mL/30 min or less, and free-water values of 0.25% or less, have been reported in the literature as requirements for slurries used in gas migration situations (Baret, 1988; Webster and Elkers, 1979).

Latexes, anionic synthetic polymers, and some cellulosic derivaties (at low temperature) are able to provide low fluid-loss rates without inducing free-water separation. However, many of them may affect other cement-slurry properties, including gel strength development and thickening time, in a deleterious fashion. Defossé (1985) described a series of metallic salts that depress free-water development, yet are not antagonistic to other aspects of slurry performance. A detailed discussion of fluid-loss additives is presented in Chapter 7.

9-6.5 Thixotropic cement slurries
Carter and Slagle (1970) identified slurry gelation as a major potential cause of gas migration. However, the work of Sabins et al. (1982) indicated that high gel strength may help resist gas percolation; for this reason, they proposed thixotropic and high-gel strength cements. (1982) indicated that high gel strength may help resist gas percolation; for this reason, they proposed thixotropic and high-gel strength cements. Carter and Slagle (1970) identified slurry gelation as a major potential cause of gas migration. However, the work of Sabins et al. (1982) indicated that high gel strength may help resist gas percolation; for this reason, they proposed thixotropic and high-gel strength cements. (1982) indicated that high gel strength may help resist gas percolation; for this reason, they proposed thixotropic and high-gel strength cements. As discussed in Chapter 7, thixotropic cements may be prepared by a number of methods, including the addition of bentonite, certain sulfate salts, or crosslinkable polymers to a Portland cement slurry. In all cases, the transmitted hydrostatic pressure of a thixotropic system should revert to that of its interstitial water and remain as such until the setting period begins. Therefore, thixotropic systems are unlikely to be effective in situations in which the gas-zone pressure exceeds the water gradient, unless additional backpressure is held on the annulus.

The high gel strength of thixotropic cements can offer considerable resistance to physical deformation and percolation by a large gas bubble. However, as discussed earlier, the bubbles may often be smaller than the pore spaces in the setting cement. Under such circumstances, gas migration may occur without slurry deformation, and gel strength is no longer an effective barrier.

Thixotropic cement slurries tend to have high fluid-loss rates; therefore, the risk of dehydration and bridging must be considered. Sykes and Logan (1987) found the influence of fluid loss to be preponderant to that of gel strength immediately after placement, and they recommended designing the slurry to be well dispersed until after the bulk of fluid-loss volume reduction has occurred. The fluid-loss problem has been reduced somewhat by the development of improved fluid-loss additives (Chapter 7). Some degree of fluid-loss control for thixotropic slurries can also be obtained by the use of low-fluid-loss spacer fluids (Bannister, 1978).

Successful field results have been obtained in shallow, low-temperature applications (Sepos and Cart, 1985). Stehle et al. (1985) reported good results at greater temperatures (250° to 280°F [120° to 140°C]) when cementing liners and long strings.

9-6.6 Surfactants
The use of surfactants in cement slurries and preflushes was first described by Marrast et al. (1975). Surfactants may, under the right circumstances, entrain invading gas downhole to create stable foam. This foam presents significant resistance to flow of discrete gas bubbles, thereby limiting their upward migration through the cement column. Stewart and Schouten (1986) reported the technique to be effective, particularly when combined with the use of elastomeric seal rings, described earlier.

9-6.7 Right-angle-set cements
Right-angle set (RAS) cement slurries can be defined as well-dispersed systems that show no progressive gelation tendency yet set almost instantaneously because of rapid hydration systems (Kieffer and Rae, 1987). Unlike high-gel strength systems, RAS systems undergo a true set involving the deposition and recrystallization of mineral hydrates. RAS slurries are sometimes characterized as such by standard high-pressure, high-temperature (HPHT) thickening time tests, as shown by Drecq and Parcevaux (1988). A RAS slurry maintains a low consistency until setting, when the slurry viscosity increases to more than 100 Bc within a few minutes. The increase in consistency is accompanied by a temperature increase resulting from the exothermic cement hydration reactions taking place (Fig. 9-21).

It is difficult to design RAS systems for temperatures below 250°F [120°C] because of the slower cement hydration kinetics at lower temperatures. It must also be noted that the shear imparted to the slurry during the API thickening time test varies significantly from that which occurs downhole during a cementing operation, making the set profile on a thickening time test merely a qualitative measure.
9-6.8 Expanding cements

Cements that exhibit bulk expansion have been advocated in places in which a microannulus is the gas migration pathway, and successful field results have been reported (Seidel and Greene, 1985). As discussed in Chapter 7, there are two principal techniques for inducing bulk expansion in Portland cement: crystal growth and gas generation. The latter operates on the same principle as the compressible cements mentioned above, with the exception that the concentration of gas-generating material (typically aluminum) is reduced (Sutton and Prather, 1986). The former relies upon the nucleation and growth of certain mineral species within the set-cement matrix. The bulk volumetric expansion that can be attained through crystal growth is usually controlled to be less than 1% (Griffin et al., 1997). The bulk expansion provided by either of these mechanisms does not eliminate internal chemical shrinkage that has previously been discussed as a cause for gas migration. It only acts to increase the bulk or dimensional volume of the cement.

Experimental work performed by Beirute et al. (1992) found that expanding cements are not effective at sealing microannuli along the casing/cement interface if the adjacent formation does not impose an adequate confining stress. Their laboratory studies indicated that the cement sheath can actually expand away from the casing when confined by soft formations. Further experimental work by Baumgarte et al. (1999) and Le Roy-Delage et al. (2000) confirmed this phenomenon, leading to recommendations to use expanding cements only across relatively hard formations that can resist the expansion and impose stresses in the cement sheath that force it to expand towards the casing.

9-6.9 Flexible cements

Cements with improved flexibility have been shown to reduce the potential for stress-induced cement-sheath cracking that may lead to long-term gas migration. Thiercelin et al. (1997) showed that the risk of failure is related to the ratio of the cement tensile strength to the Young's modulus. The larger this ratio (i.e., cement with relatively high tensile strength and low Young's modulus), the more resistant the cement is to failure.

Onan et al. (1993) reported the use of elastomeric polymers to improve set-cement flexibility. Le Roy-Delage et al. (2000) incorporated flexible particles such as rubber, thermoplastics, or latexes in cement systems as a method for improving flexibility. Foamed cement has also been shown to improve flexibility (Deeg et al., 1999). More detailed information about these methods can be found in Chapter 7.

9-7 Laboratory testing

At this writing, neither API nor the International Organization for Standardization have published a standard method or procedure for testing gas migration control in cement slurries; therefore, there is no recognized standard laboratory procedure to characterize the ability of a cement system to prevent or reduce gas migration.

A significant number of nonstandard laboratory tests for gas migration has been developed by the industry. A wide variety of experimental prototypes that attempt to simulate the gas migration process are described in the literature. Two main types of experimental simulators exist: large-scale pilot devices, which attempt to reproduce the process as it occurs in the wellbore, and small-scale, benchtop models, which can be used to derive the fundamental laws of a particular physical process under investigation. To date, none of the simulators described in the literature permits the derivation of a physical model that quantitatively describes gas migration over a wide range of conditions. Recently, many investigators have begun to rely upon measuring individual slurry properties such as gel strength development and shrinkage. These data are then used either as input into mathematical simulators or for comparing the performance differences between various slurries.
9-7.1 Large-scale testing

Typically, large-scale models have been constructed in an effort to better understand gas migration phenomena and are not practical for conducting routine experiments for individual well designs. The earliest large-scale simulation was performed by Carter and Slagle (1970) and later upgraded by Carter et al. (1973). In 1976, Garcia and Clark constructed a large-scale device specifically to study the influence of uneven cement setting. Levine et al. (1979) described a simulator for studying hydrostatic pressure profiles within a cement column at rest (Fig. 9-8). The apparatus built by Tinsley et al. (1979) investigated the influence of fluid loss and compared different cement systems (Fig. 9-22). Finally, the equipment described by Bannister et al. (1983) evaluated the influence of filtercake formation from cement fluid loss and the conductivity to gas of setting cement (Fig. 9-23).

9-7.2 Small-scale gas migration testers

Various bench-scale or benchtop devices for characterizing gas migration have been described in the literature. The first, described by Cheung and Beirute (1982), used a modified API fluid-loss cell to investigate the hydrostatic pressure decrease and subsequent gas migration in a setting cement column (Fig. 9-24). Adaptations of this model have recently been made commercially available and are known as gas migration analyzers or gas flow analyzers (Fig. 9-25). The test cell is a modified API HPHT fluid-loss cell with a hollow hydraulic piston at the top of the cell. The piston is pressurized with mineral oil to simulate the hydrostatic overbalance. Fluid loss can occur at both the top and the bottom of the cell, either through standard 325-mesh fluid-loss screens or through actual formation cores. Once the cement slurry has developed a predetermined gel strength, gas is injected into the bottom of the cell at an appropriate differential pressure. Gas flowmeters and pressure transducers measure any gas migration through the slurry. A separate gel strength–development test (described in Section 9-7.3) must be performed on the slurry before performing this gas migration test.
While this device has been adapted for routine use, it is important to note that, at the scale of this test, three factors can unduly affect the gas migration process. Fluid loss could result in the formation of an impenetrable filtercake at the gas inlet or outlet. Free-water development could artificially delay the pore pressure decrease by reabsorption during hydration. Finally, in view of the length of the cement column versus the external applied pressure, such an experiment can only consider gas migration across a short interval.

Stewart and Schouten (1986) investigated gas migration in set and hard cement using a U-tube apparatus like that shown in Fig. 9-26 (Richardson, 1982).

Parcevaux (1984a) and Drecq and Parcevaux (1988) described a small-scale simulator that eliminated some of the limitations of earlier devices. As illustrated in Fig. 9-27, the artificial effects of fluid loss and free water were eliminated, and the external curing pressure was computer-controlled to maintain a differential pressure close to zero between the top and bottom of the cell.

**Figure 9-24.** Gas flow simulator (from Cheung and Beirute, 1982). Reprinted with permission of SPE.

**Fig. 9-25.** Gas flow apparatus (photo courtesy Chandler Engineering LLC).
Another bench-scale device called the cement hydration analyzer (CHA) was first described in a 1997 API Technical Report (TR) 10TR2, *Technical Report on Shrinkage and Expansion in Oilwell Cements*. This device was developed to measure the evolution of critical parameters during cement hydration and to better understand the mechanisms of gas entry downhole. Under fixed-pressure conditions, the CHA measures hydration rate, shrinkage (with regard to chemical contraction or development of porosity as the slurry hydrates), and mechanical properties.

The gas migration cell is an 8-in. long, 2-in. diameter disposable cylinder (Fig. 9-28). The top of the cell is closed and contains a pressure transducer and a temperature probe. At the bottom of the cell, a sliding piston (or diaphragm), connected to a gas source, is used to pressurize the slurry. The rate of the gas entering the cell and the rate of the water pushing the piston as shrinkage develops are carefully monitored. The cell is placed in a thermostatic oven until thermal equilibrium is reached. As long as the cement slurry remains liquid, the pressure measured at the top of the cell stays constant. The upward movement of the piston compensates for any slurry shrinkage. As the slurry hydrates, the temperature in the cell increases and shrinkage continues. The piston movement is eventually stopped by the increasing wall shear stress of the slurry, and the pressure at the top of the cell decreases. When the pressure at the top of the cell falls to a predetermined value, the gas valve connected to the piston is opened. The gas is allowed to enter the cell, driven by the pressure decrease and the continuing shrinkage of the cement.

The permeability of the slurry to gas can be determined by analyzing the pressure and gas flow rate (Fig. 9-29). If the cement is permeable to gas, the pressure in the cell will reach equilibrium with the gas-inlet pressure once the gas valve is opened, and gas flow can be measured by the gas flowmeter. The amount of gas that enters the cell gives a good indication of the amount of shrinkage. A visual observation of the cement after the test can indicate the manner by which gas migrated (bubbles, micropercolation, or fracture). If the cement is impermeable to gas, the pressure in the cell will continue to decrease and no gas flow will be observed.

![Fig. 9-26. U-tube gas migration tester (from Richardson, 1982).](image1)

![Fig. 9-27. Dynamic permeability apparatus (from Parcevaux, 1984a). Reprinted with permission from Elsevier.](image2)
Fig. 9-29. Output from the CHA. Cement that is permeable to gas (top) will exhibit a stable pressure in the cell equal to the gas-inlet pressure, and gas flow will be measured with the gas flowmeter, while cement that is impermeable to gas (bottom) will exhibit a continued pressure decrease caused by shrinkage and no gas flow will be measured.
9-7.3 Gel strength testing

Numerous methods for measuring the static gel strength (SGS) of cement slurries have been developed. Today there are four common methods: using pressure-drop tubes, using vane rheometers, using rotating-paddle devices, and employing acoustic techniques. It is important to note that comparative testing between these devices has shown significant variations in the measured SGS. As noted by Prohaska et al. (1993), gel strength development can be significantly impacted by the amount of shear that is applied to the slurry before commencing measurement and the pressure and temperature that the slurry encounters. These factors, along with the inherent differences in the devices, account for the variability in results between the various methods.

9-7.3.1 Pressure drop tubes

One of the simplest means of measuring SGS is by measuring the pressure drop across a length of tubing (Fig. 9-30). Cement slurry is placed in a small-diameter tube and pressurized with water. A sensitive pressure transducer measures the pressure drop in the cement column as it undergoes gelation. Equation 9-20 can then be used to calculate the SGS. One limitation of this test is that it is not able to differentiate between pressure drop caused by gelation and pressure drop caused by chemical shrinkage.

A similar modification of this method is known as the shearometer tube. This device consists of a thin-walled tube that is placed in a sample of cement slurry and allowed to rest statically for a given period of time. Weights are then applied to the top of the tube until it begins to move, and the SGS is calculated based upon the force imparted by the weights and the surface area of the tube. This test can only be carried out at atmospheric pressure.

9-7.3.2 Vane rheometers

Early SGS testing was attempted using standard rotational viscometers by measuring the maximum deflection of the bob while rotating at 3 rpm after the slurry had been static for a designated period of time (normally 1 min or 10 min) (Appendix B). Slippage at the interface between the bob and the cement slurry, coupled with the relatively high minimum shear rates (5.1 sec⁻¹), gave unreliable results. Furthermore, this test could only be carried out under ambient conditions. In an effort to reduce interfacial slippage, Haimoni and Hannant (1988) replaced the cylindrical bob with a vane. In the late 1990s, the vane geometry was further advanced. The improved device allowed testing at elevated temperature and pressure. In addition, the device allowed one to impart stress into the static slurry without shearing it and disturbing the evolving gel structure (Fig. 9-31).

9-7.3.3 Rotating-paddle devices

Sabins et al. (1980) developed a device designed specifically to test SGS at elevated temperature and pressure. The device, similar to a HPHT consistometer, used a specially designed paddle placed inside a pressurized slurry container. The slurry could be stirred with a low-friction magnetic drive to simulate placement. After stirring, a cord-and-weight bucket was attached to the magnetic drive, and the weight required to rotate the paddle 10° was measured at specific time intervals (normally 5 to 15 min). The SGS could then be calculated from the geometry of the paddle and the weight required to move it. Further improvements to this device, which included direct torque measurement, were patented by Moon et al. (Fig. 9-32) (1986).
9-7.3.4 Acoustic devices

As a cement sample develops SGS, the amplitude of an acoustic signal passing through the sample increases. Correlations can be developed between the change in amplitude of the acoustic signal and the SGS of the slurry. Using this concept, Sabins and Maki (1999) produced a device similar to the ultrasonic cement analyzer (Appendix B) that could measure the SGS (Fig. 9-33).

An apparent advantage of this method is that the slurry is not mechanically sheared; therefore, the SGS is measured at zero shear rate. However, it is important to note that, similar to that of the ultrasonic cement analyzer, the gel strength is not a direct measurement, but only a correlation that has been established by comparison of acoustic signal attenuation and testing with pressure-drop tubes and shearometers.

9-8 Conclusions

Gas migration is a complex phenomenon involving fluid-density control, mud removal, cement-slurry properties, cement hydration, and interactions between the cement, casing, and formation. It has been the subject of a substantial amount of research over the past 50 years, yet it remains one of the most serious cementing problems the industry faces. Uncontrolled, gas migration can lead to loss of production, environmental and regulatory problems, and ultimately risk to equipment and personnel. The cost of remediating a gas migration problem can far exceed the costs of active prevention.

Gas migration can be categorized according to when it occurs in relationship to the cement job. Gas migration that occurs during cementing can be referred to as immediate gas migration; gas migration that occurs after...
the cement is in place but before it has set is referred to as short-term gas migration; and gas migration that occurs after the cement has set is referred to as long-term gas migration. Regardless of when it occurs, there are three distinct root causes that must occur for annular gas to migrate.

1. The pressure in the annulus must fall to a value that is less than or equal to the pore pressure of a gas-bearing zone.
2. Space must be available in the annulus for gas to occupy in order for it to enter the annular column.
3. A path must be present in the annulus through which the gas can migrate.

Successful strategies, both theoretical and practical, for controlling gas migration rely on minimizing the impact of one or more of these root causes. Particular factors that should be addressed include fluid loss, gel strength development, cement shrinkage, cement permeability, free fluid, cement hydration kinetics, mechanical properties of the set cement, and last, but not least, proper mud removal.

Because the factors surrounding gas migration are so complex, it must be understood that there is no single solution for all cases. Numerous predictive models designed to understand and assess the risk of gas migration for a given set of conditions have been developed. These models, coupled with the appropriate laboratory techniques, aid the engineering and design of cementing programs that will significantly minimize the likelihood of annular gas migration.

9-9 Acronym list

<table>
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<tr>
<th>Acronym</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>API</td>
<td>American Petroleum Institute</td>
</tr>
<tr>
<td>CHA</td>
<td>Cement hydration analyzer</td>
</tr>
<tr>
<td>CHP</td>
<td>Critical hydration period</td>
</tr>
<tr>
<td>ECP</td>
<td>External casing packer</td>
</tr>
<tr>
<td>FP</td>
<td>Formation parameter</td>
</tr>
<tr>
<td>GFP</td>
<td>Gas flow potential</td>
</tr>
<tr>
<td>HF</td>
<td>Hydrostatic factor</td>
</tr>
<tr>
<td>HPHT</td>
<td>High pressure, high temperature</td>
</tr>
<tr>
<td>MRF</td>
<td>Mud removal factor</td>
</tr>
<tr>
<td>MPR</td>
<td>Maximum pressure restriction</td>
</tr>
<tr>
<td>MRP</td>
<td>Mud removal parameter</td>
</tr>
<tr>
<td>PDLP</td>
<td>Pressure decay limit parameter</td>
</tr>
<tr>
<td>RAS</td>
<td>Right-angle set</td>
</tr>
<tr>
<td>RP</td>
<td>Recommended practice</td>
</tr>
<tr>
<td>SGS</td>
<td>Static gel strength</td>
</tr>
<tr>
<td>SPN</td>
<td>Slurry performance number</td>
</tr>
<tr>
<td>TR</td>
<td>Technical report</td>
</tr>
</tbody>
</table>
10-1 Introduction

High-temperature wells present special cement system design challenges. The physical and chemical behavior of well cements changes significantly at elevated temperatures and pressures. One must also pay close attention to the chemical and physical properties of the formations in contact with the cement. Corrosive water zones and very weak formations are not uncommon in thermal wells. Without careful slurry design, the integrity of the set cement may deteriorate, potentially resulting in the loss of zonal isolation.

Thermal cementing encompasses three principal types of wells: deep oil and gas wells, geothermal wells, and thermal recovery wells. In this chapter, each scenario is discussed separately, because the cement system design parameters can differ significantly.

During the last 50 years the most commonly used cements to complete thermal wells have been Portland cement, silica-lime systems, and high-alumina cement. More recently, other cement systems have been developed specifically for thermal-well environments. Before discussing the cement system design for the various types of thermal wells, the hydrothermal chemistry of cements used to complete thermal wells is presented. In this chapter, the special chemical notation for cement compounds is used. The reader is referred to Chapter 2 for an explanation of the customary abbreviations.

10-2 High-temperature chemistry of Portland cement

As discussed in Chapter 2, Portland cement is essentially a calcium silicate material, the most abundant components being tricalcium silicate (C₃S) and dicalcium silicate (C₂S). Upon addition of water, both hydrate to form a gelatinous calcium silicate hydrate called “C-S-H phase,” which is responsible for the strength and dimensional stability of the set cement at ordinary temperatures. The reaction also liberates a substantial amount of calcium hydroxide (CH).

C-S-H phase is the early hydration product even at elevated temperatures and pressures, and it is an excellent binding material at well temperatures less than 230°F [110°C]. At higher temperatures, C-S-H phase is subject to metamorphism, which usually results in decreased compressive strength and increased permeability of the set cement. In the petroleum literature, Swayze (1954) described this phenomenon as “strength retrogression.”

At temperatures above 230°F [110°C], C-S-H phase often converts to a phase called alpha dicalcium silicate hydrate (α-C₂SH). α-C₂SH is highly crystalline and much more dense than C-S-H phase. As a result, matrix shrinkage occurs that can be deleterious to the set-cement integrity. This effect is illustrated in Fig. 10-1, which depicts the compressive-strength and water-permeability behavior of conventional Portland cement systems.

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**Fig. 10-1.** Compressive strength and water permeability behavior of Portland cement at elevated temperatures (from Nelson and Eilers, 1985).
cured at 446°F [230°C]. Significant loss of compressive strength occurred within 1 month; nevertheless, the levels to which the compressive strength fell are sufficient to support casing in a well (Suman and Ellis, 1977). The real problem lies in the severe permeability increases. To prevent interzonal communication, the permeability of well cements to water should be no more than 0.1 mD. Within 1 month, the water permeabilities of the normal-density Class G systems portrayed in Fig. 10-1 (Curves 1 and 2) were 10 to 100 times higher than the recommended limit. The permeability of the high-density Class H system (Curve 3) was barely acceptable. The deterioration of the lower-density extended cement (Curve 4) was much more severe.

The strength retrogression problem can be prevented by reducing the bulk lime-to-silica ratio (C/S ratio) in the cement (Menzel, 1935; Kalousek, 1952; Carter and Smith, 1958). To accomplish this, the Portland cement is partially replaced by ground quartz, usually as fine silica sand or silica flour. In some regions, special cements are available in which quartz has been ground with Portland cement clinker (Italcementi, 1977). Figure 10-2 depicts the conditions for the formation of various calcium silicate compounds, many of which occur geologically (Taylor, 1964). The C/S ratio is plotted versus the curing temperature. C-S-H phase has a variable C/S ratio, averaging about 1.5. The conversion to α-C2S at 230°F [110°C] can be prevented by the addition of 35% to 40% silica (by weight of cement [BWOC]), reducing the C/S ratio to about 1.0. At this level, a mineral known as tobermorite (C5S6H5) is formed; fortunately, this mineral preserves high compressive strength and low permeability. As the curing temperature increases to about 300°F [150°C], tobermorite normally converts to xonotlite (C6S6H) and a smaller amount of gyrolite (C6S3H2) with minimal deterioration of cement performance. Tobermorite sometimes persists to 480°F [250°C] in Portland cement systems because of aluminum substitution in the lattice structure (Kalousek and Chow, 1976). The improved performance of “silica-stabilized” Portland cements at elevated temperatures is illustrated in Fig. 10-3. Normal-density Class G cements, stabilized with silica sand or silica flour, were cured at 446° and 608°F [230° and 320°C].

Fig. 10-2. Formation conditions for various calcium silicates (from Taylor, 1964). Reprinted with permission from Elsevier.
At 480°F [250°C] the phase truscottite (C₁₇S₁₂H₃) begins to appear. As the curing temperature approaches 750°F [400°C], both xonotlite and truscottite are near their maximum stable temperatures, and dehydration of the residual CH to C occurs. At higher temperatures, the xonotlite and truscottite dehydrate, resulting in the disintegration of the set cement.

In addition to the compounds cited above, other phases such as pectolite (NC₄S₆H), scawtite (C₇S₆C–H₂), reyerite (KC₁₄S₂₄H₅), kilchoanite (C₃S₂H approximately), and calciochondrodite (C₅S₂H approximately) may appear in Portland cement systems cured at elevated temperatures. These phases can affect the performance of the set cement, even when present in small quantities.

Cements containing significant amounts of truscottite are usually characterized by low permeability (Gallus et al., 1978). The formation of pectolite, a sodium calcium silicate hydrate, is accompanied by cement expansion (Nelson and Eilers, 1982); in addition, pectolite appears to render cements more resistant to corrosion by highly saline brines (Nelson and Kalousek, 1977; Nelson et al., 1981). Scawtite has been shown to enhance cement compressive strength when present in minor amounts (Eilers et al., 1983; Bell et al., 1989). In general, set cements that consist predominantly of calcium silicate hydrates with C/S ratios less than or equal to 1.0 tend to have higher compressive strengths and lower water permeabilities.

The discussion so far has been limited to the behavior of the silicate hydration products. To the authors’ knowledge, the hydrothermal behavior of the aluminates and aluminoferrites has not been specifically described in the literature. The common hydrated aluminate and aluminoferrite hydrates (Chapter 2) are not typically observed when Portland cements are cured hydrothermally. Ettringite is not stable in hydrothermal conditions, and is not normally detected. Some of the Al³⁺, Fe³⁺, and SO₄²⁻ ions from ettringite are incorporated into the silicate phases.

The preceding discussion illustrates the complexity of the hydrothermal behavior of calcium silicate hydrates. The performance of the set cement depends not only on the downhole temperature, but also on the presence of subterranean brines and other minerals. As a result, the standard conditions for equilibrium transformations that are reported in the literature are not always observed downhole (Langton et al., 1980). Therefore, the set cement must be considered to be metastable, because its composition can evolve as downhole conditions change.
10-3 High-alumina cement

High-alumina cement is a special material manufactured primarily for applications in which a refractory binder is required (Robson, 1962; Scrivener and Capmas, 2001). In wells, it is used where the in situ combustion process is employed for fireflooding (Section 10-8) and is also useful for cementing across permafrost zones (Chapter 7). The primary cementitious constituent is monocalcium aluminate (CA). As illustrated in Fig. 10-4, three initial metastable calcium aluminate hydrates occur when water is added to CA: CAH₁₀, C₂AH₈, and C₄AH₁₃. They ultimately convert to C₃AH₆ (Quon and Malhotra, 1979). In addition to C₃AH₆, aluminum hydroxide (AH₃) is often present as a binder phase. Unlike Portland cement, set calcium aluminate cement does not contain calcium hydroxide.

C₃AH₆ is probably the only stable hydrated calcium aluminate at temperatures below 437°F [225°C]. At higher temperatures, the water content begins to drop, and at 527°F [275°C], C₃AH₁₅ is found. As the temperature continues to increase, decomposition of C₃AH₁₅ occurs with the liberation of C. Between 1,022°F [550°C] and 1,742°F [950°C], a recrystallization occurs, ultimately resulting in C and C₁₂A₇.

It is important to realize that, in ultrahigh-temperature wells with temperatures up to 930°F [500°C], C₁₂A₇ crystals intergrow and form a tightly bonded ceramic network. In thermal wells, temperatures above 1,830°F [1,000°C] are not generally attained; thus, it is important to ensure that the minimum compressive strength is sufficient for maintenance of well integrity.

The strength and durability of high-alumina cements between 440° and 1,830°F [225° and 1,000°C] are primarily controlled by the initial water-to-cement ratio. Depending upon the application, the amount of added water should be the minimum required to prepare a pumpable slurry. The use of dispersants is particularly helpful for pumpability. A higher proportion of cement relative to aggregate extender is also necessary. For most applications, at least 50% of the solids should be cement.

A variety of materials may be used to extend calcium aluminate cement slurries, provided they have suitable stability at high temperatures and do not decompose or show anomalous thermal expansions or inversions. Silica sand should not be used if temperatures exceeding 572°F [300°C] are anticipated. Because of changes in the crystalline structure, thermal expansion of quartz is relatively high at these temperatures, and thermal cycling could eventually disrupt the cement. The most commonly used extender for high-alumina cements is crushed aluminosilicate firebrick. Other suitable materials include calcined bauxite, certain fly ashes, diatomaceous earth, and perlite.

10-4 Class J cement

Class J cement was developed in the early 1970s for cementing wells with static temperatures exceeding 260°F [126°C] (Maravilla, 1974; Degouy and Martin, 1993; Bensted, 1995). It was recently dropped from the list of American Petroleum Institute (API) cements.
owing to low usage; however, it is still manufactured in the Far East, mainly for geothermal well applications. A similar cement, belite-silica cement (BSC) has been used in the CIS for high-temperature well cementing (Bulatov, 1985). These cements are advantageous from a logistical point of view, because the addition of silica is not required.

Like Portland cement, Class J cement is a calcium silicate material; however, no aluminate phases or C₃S is present. The composition is essentially β-C₂S, α-quartz, and CH. As discussed in Chapter 2, the hydration rate of β-C₂S is relatively slow; consequently, retarders are rarely necessary at circulating temperatures less than 300°F [149°C]. The C/S ratio of Class J cement is adjusted such that tobermorite and xonotlite are obtained upon curing (Sasaki et al., 1986; Kalousek and Nelson, 1978). Scawtite also occurs frequently. In addition, the sulfate resistance of Class J cement is very high owing to the absence of C₃A.

### 10-5 Calcium aluminosilicate systems

In the late 1970s, Roy et al. (1979; 1980) reported work to develop cement systems that resemble the composition of the formation in geothermal wells. Such cements should exhibit better chemical and thermal durability than the conventional calcium-silicate or calcium-aluminate systems. Of particular interest was the CaO • Al₂O₃ • SiO₂ system (Fig. 10-6). In a hydrothermal environment, the stable minerals would be anorthite, grossular, prehnite, epidote, and zeolite, possibly associated with quartz (Frey et al., 1991). Roy et al. experimented with compositions that would lead to the formation of the mineral anorthite. The raw materials were Class J cement, calcium aluminate cement, and β-C₂S. The results were encouraging in terms of strength; however, the preparation of mixable and pumpable slurries, with controllable set times, was a serious problem.

More recently, other approaches to preparing anorthite cements were investigated (Barlet-Gouédard and Goffé, 2002). To promote the formation of anorthite, various alumina-rich materials were evaluated in combination with Class G cement and silica flour. Calcined kaolinite was determined to be an ideal alumina source; however, it must be very finely divided (≈2 μm) to provide sufficient reactivity to readily form anorthite. As a result, similar to the experience of Roy et al., Barlet-Gouédard and Goffé initially encountered difficulties preparing a mixable and pumpable system. Their solution involved controlling the particle sizes of the ingredients and optimizing the packing between them. Such controlled-granulometry techniques are described in detail in Chapter 7. The anorthite system is a trimodal mixture: calcined kaolinite and silica flour (fine particles), Class G cement (medium-size particles), and ceramic microspheres (coarse particles). The microspheres are also useful for lowering slurry density.

![Fig. 10-6. Ternary diagram showing compositions of minerals in the CaO • Al₂O₃ • SiO₂ system.](image-url)
A complete solid-solution series extends from anorthite, Ca(Al₂Si₂O₈), to albite, Na(AlSi₃O₈). As a result, anorthite can accommodate the substitution of various ions into its crystal lattice. This property makes anorthite adaptable to aggressive chemical environments. The typical properties and performance of an anorthite cement exposed to a carbon dioxide-laden synthetic geothermal brine are given in Table 10-1.

### 10-6 Calcium phosphate systems

Calcium phosphate cement systems were originally developed for applications in dentistry. Recently such cements have found application as thermal cements (Sugama and Carciello, 1992; 1993; 1995), particularly for geothermal wells in which high concentrations of carbon dioxide are encountered (Weber et al., 1998; Brothers et al., 2001). Portland cement systems are subject to attack by CO₂, resulting in the loss of cementitious material from the cement matrix (Chapter 7). The consequences of CO₂ attack are loss of compressive strength and an increase of permeability.

Calcium phosphate cements can be synthesized by the acid-base reaction between a soluble phosphate [usually NaH₂PO₄ or (NaPO₃)ₙ] as the acid solution and calcium aluminate cement as the base reactant. The principal cementitious phase is hydroxyapatite [Ca₅OH(PO₄)₃]. Such systems normally set and harden within a few minutes at ambient temperature. Citric acid is an effective set retarder at circulating temperatures up to around 180°F [82°C] (Brothers et al., 1999).

Calcium phosphate cement normally has a density in the range of 15–17 lbm/gal [1,800–2,040 kg/m³]. To reduce the cost or the density of the slurry, extenders are usually added. The most common extenders include ASTM Class F fly ash or nitrogen, which is used to prepare a foamed cement system (Brothers et al., 2001). The composition and compressive-strength performance of foamed calcium phosphate systems are shown in Table 10-2.

The carbon dioxide resistance of calcium phosphate cement, compared to conventional silica-stabilized Portland cement, is shown in Table 10-3. The cement systems were cured in 1-wt% Na₂CO₃ solution at two temperatures: 200° and 500°F [93° and 260°C]. The solution pH was 2.0–2.7. The weight loss of the cement specimens was measured at curing times of up to 32 days. The results clearly show that, within the 32-day test period, the calcium phosphate binder demonstrated excellent resistance to carbonation.

### Table 10–1. Typical Performance of Anorthite Cement Systems

<table>
<thead>
<tr>
<th>Slurry Density (lbm/gal [g/cm³])</th>
<th>Plastic Viscosity (cp)</th>
<th>Yield Point (lbm/100 ft²)</th>
<th>Thickening Time at 300°F [150°C] BHCT†</th>
<th>28-D Compressive Strength in Brine at BHST‡ of 572°F [300°C] (psi [MPa])</th>
<th>Water Permeability at 28 D in Brine at BHST of 572°F [300°C] (mD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>10.9 [1.31]</td>
<td>75</td>
<td>0.6</td>
<td>5:00</td>
<td>1,400 [9.8]</td>
<td>0.2</td>
</tr>
<tr>
<td>12.4 [1.49]</td>
<td>130</td>
<td>6</td>
<td>3:00</td>
<td>2,320 [16.2]</td>
<td>0.05</td>
</tr>
<tr>
<td>13.5 [1.62]</td>
<td>144</td>
<td>6</td>
<td>5:40</td>
<td>2,200 [15.4]</td>
<td>0.03</td>
</tr>
<tr>
<td>14.0 [1.68]</td>
<td>110</td>
<td>4</td>
<td>3:30</td>
<td>2,570 [18.0]</td>
<td>–</td>
</tr>
<tr>
<td>16.2 [1.95]</td>
<td>55</td>
<td>10</td>
<td>7:40</td>
<td>2,290 [16.0]</td>
<td>–</td>
</tr>
</tbody>
</table>

† BHCT = bottomhole circulating temperature
‡ BHST = bottomhole static temperature

### Table 10–2. Composition and Performance of Calcium Phosphate Cement Systems Cured at 600°F†

<table>
<thead>
<tr>
<th>Water (wt%)</th>
<th>Calcium Aluminate (wt%)</th>
<th>Sodium Polyphosphate (wt%)</th>
<th>Fly Ash (wt%)</th>
<th>Foaming Agent (wt%)</th>
<th>Foam Stabilizer (wt%)</th>
<th>Slurry Density (lbm/gal [kg/cm³])</th>
<th>28-Day Compressive Strength at BHST of 572°F [300°C] (psi [MPa])</th>
</tr>
</thead>
<tbody>
<tr>
<td>23.3</td>
<td>17.5</td>
<td>15.6</td>
<td>40.8</td>
<td>1.9</td>
<td>0.9</td>
<td>12.1 [1,450]</td>
<td>570 [4.0]</td>
</tr>
<tr>
<td>22.3</td>
<td>21.0</td>
<td>14.9</td>
<td>39.2</td>
<td>1.8</td>
<td>0.8</td>
<td>15.1 [1,810]</td>
<td>1,060 [7.4]</td>
</tr>
</tbody>
</table>

† from Brothers et al. (1999)
10-7 Deep oil and gas wells

Wells with depths exceeding 15,000 ft [4,570 m], with bottomhole temperatures above 230°F [110°C], are common throughout the world. Since the 1970s, hundreds of wells with depths exceeding 25,000 ft [7,600 m] have been completed (Arnold, 1980; Wooley et al., 1984). Such wells represent a large investment of time and money; therefore, obtaining a successful well completion is of paramount importance.

The procedures for cementing deep wells are basically the same as those for shallower wells; however, because of the severe well conditions and more complex well architecture, such wells are usually considered to be critical (Smith, 1987). Higher temperatures, narrower annuli, overpressured zones, and corrosive fluids are commonly encountered. Consequently, the cement system design can also be complex, involving an elaborate array of retarders, fluid-loss additives, dispersants, silica, and weighting materials. One must be certain that the cement system can be properly placed and will maintain zonal isolation throughout the life of the well. At present, Portland cement is used in virtually all deep oil and gas well completions.

Typical casing programs and cementing procedures for deep wells are given in Chapter 13. Detailed information regarding cement additives is found in Chapter 3. In this section, the design of appropriate cement systems for deep high-temperature wells is presented.

10-7.1 Thickening time and initial compressive strength development

Cement slurries for deep wells are usually designed to have at least 3 to 4 hr of pumping time. However, there are several complicating factors that must be mentioned.

As the length of the casing string or liner increases, the problem of achieving a cement seal becomes more difficult (Suman and Ellis, 1977). In many cases, the static-temperature differential between the top and bottom of the cement column can exceed 100°F [38°C]. Sufficient retarder must be added to the cement slurry to allow adequate placement time at the BHCT; consequently, such a slurry may be over-retarded at the top of the cement column, resulting in a very long waiting-on-cement (WOC) time. If high-pressure gas exists behind the casing string or liner, the risk of gas invasion into the cement is high (Chapter 9). In recent years, advances have been made in retarder chemistry and cement-system design that have helped to mitigate such problems (Chapter 3).

When designing cement slurries for deep, hot wells, it is very important to use accurate static and circulating temperature information. Such data may be obtained from drillstem tests, logs, special temperature recording subs, or circulating temperature probes run during hole conditioning (Jones, 1986). Computer simulators have also been developed to better predict well temperatures (Chapter 12). If fluids are circulated in the well for several hours before cementing, the well temperature may be lowered significantly. In such cases, one must be careful not to overestimate circulating temperature and over-retard the cement slurry.

Table 10–3. Corrosion-Test Results of Thermal Cements in 1% Na₂CO₃ Solution; pH = 2.0–2.7

<table>
<thead>
<tr>
<th>Slurry</th>
<th>Slurry Density (lbm/gal)</th>
<th>Test Temperature (°F)</th>
<th>Percent Weight Loss After:</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>2 D</td>
</tr>
<tr>
<td>Calcium phosphate</td>
<td>15.7</td>
<td>200</td>
<td>0.1</td>
</tr>
<tr>
<td>Class G + 40% silica</td>
<td>16.2</td>
<td>200</td>
<td>1.6</td>
</tr>
<tr>
<td>Calcium phosphate</td>
<td>16.0</td>
<td>500</td>
<td>0</td>
</tr>
<tr>
<td>Class G + 40% silica</td>
<td>16.2</td>
<td>500</td>
<td>9.5</td>
</tr>
</tbody>
</table>

† from Weber et al. (1988).

Chapter 10 Thermal Cements
The cement slurry is exposed to high pressures in deep wells and, as shown in Fig. 10-7, a significant accelerating effect is observed (Bearden, 1959). Earlier compressive strength development and higher ultimate compressive strength are also observed as curing pressure increases (Handin, 1965; Metcalf and Dresher, 1978). Therefore, when designing a proper cement-slurry composition in the laboratory, performing the tests at the anticipated pressure is recommended (Appendix B).

In general, as the circulating temperature increases, the sensitivity of Portland cement systems to subtle chemical and physical differences between the slurry ingredients also increases. Therefore, all laboratory tests should be performed with samples of the water, cement, and additives that will be used during the job.

10-7.2 Cement-slurry rheology

The narrow annuli often associated with deep-well completions increase the difficulty of achieving a good bond between the cement, the pipe, and the formation. The small clearance between the casing and the formation increases the risk of cement contamination by drilling fluid that was not displaced by chemical washes or spacers. Proper casing centralization can be difficult to achieve. As discussed in Chapter 5, the rheology of the fluids in the wellbore should be carefully controlled. In some cases, the cement slurry is designed for turbulent-flow displacement, requiring the use of dispersants. When designing highly dispersed slurries, one must be careful to avoid slurry sedimentation or free-water development. This is especially important when the borehole is highly deviated (Chapter 13).

10-7.3 Cement-slurry density

Deep wells often involve cementing across high-pressure formations. To maintain control of the well, the hydrostatic pressure of the wellbore fluids must meet or exceed the formation pressure at all times. Consequently, cement slurries with densities as high as 27 lbm/gal [3.24 g/cm³] are often placed. When large quantities of weighting materials are present in the slurry, slurry sedimentation can be a major concern. Maximizing the packing volume fraction of the slurry solids, using a multimodal particle size distribution, can mitigate such problems (Chapter 7). Silica can be incorporated in one of the granulometric fractions to provide stabilization.

10-7.4 Fluid-loss control

As discussed in Chapters 3 and 6, fluid-loss control is necessary to preserve the chemical and physical characteristics of the cement slurry and to prevent the development of a cement filtercake that could cause bridging in the annulus. For most primary cementing operations, an API/ISO fluid-loss rate of between 50 and 100 mL/30 min is generally considered to be adequate.

10-7.5 Long-term performance of cements for deep wells

Once the cement system is successfully placed in the annulus, it is important to ensure that it will provide adequate casing support and zonal isolation throughout the life of the well. As discussed earlier in this chapter, the most common thermal cement systems are based on silica-stabilized Portland cement.

A typical slurry composition for a deep, hot well would consist of Class H or Class G cement, 35% to 40% silica (BWOC), a dispersant, a fluid-loss additive, a retarder, and a weighting agent. The long-term performance of such cement systems would be very similar to that shown in Fig. 10-3.

When high-density slurries are unnecessary, or if lower-density slurries are required to prevent lost circulation or formation breakdown, extenders such as fly ash, diatomaceous earth, bentonite, or perlite are commonly used. The long-term performance of typical systems in laboratory tests is illustrated in Figs. 10-8 and 10-9. All systems contained 35% silica flour (BWOC). In Fig. 10-8, the systems have been cured at 450°F [232°C] under saturated steam pressure for up to 2 years, and compressive strength and permeability measurements have been performed at periods ranging from 1 day to 24 months. Figure 10-9 presents data for systems cured at 600°F [315°C]. It is important to note the nonlinear time scale and the logarithmic permeability scale.

![Fig. 10-7. Effect of pressure on pumpability of cement (cement: API Class H with 0.3% retarder; BHCT: 200°F [93°C]) (after Smith, 1976). Reprinted with permission of SPE.](image-url)
System 1 contained Type F fly ash as an extender and was the heaviest of the four. Despite the density advantage and the highest initial compressive strength, the performance of System 1 over a 2-year period was no better than that of lower-density systems at 450°F [232°C], and was the poorest of the four at 600°F [315°C]. This delayed degradation of fly-ash-containing systems was probably the result of alkali contaminants in the fly ash. Such contaminants can slowly react and form substituted calcium silicate hydrates, notably reyerite, with deleterious effects (Eilers and Root, 1974). It is important to mention that cement degradation associated with fly ash has not been observed at curing temperatures below 450°F [232°C].

Systems 2 and 3 were extended with perlite and bentonite. System 2 performed well at both 450°F and 600°F [232°C and 315°C] with regard to compressive strength. The permeability of System 2 varied back and forth across the 0.1-mD line. System 3 was the least dense of the four. The compressive strength performance was adequate at both curing temperatures, but the permeabilities were too high. It is important to point out that perlite is compressible, and its extending effect decreases as the hydrostatic pressure in the well increases (Chapter 3). For this reason, perlite is rarely used today. System 4, containing diatomaceous earth, was a rather poor performer in the strength category, yet had low permeability.
Figure 10-10 shows the typical performance of a normal-density neat Class J system. Its behavior is similar to that observed with normal-density silica-stabilized Portland cement systems.

The behavior of these systems illustrates that high compressive strength and low water permeability are not necessarily linked. Although water permeability is not as convenient to determine as compressive strength (Appendix B), one should do so before the application of a cement system in severe downhole conditions. In addition, the data suggest that conventionally extended Portland cement systems with densities below about 12.5 lbm/gal [1.5 g/cm³] may not be able to perform suitably in high-temperature wells, except perhaps as “filler” systems that are not placed across producing zones.

If competent cement systems with densities less than 12.5 lbm/gal [1.5 g/cm³] are necessary, microsphere-extended, multimodal-particle-size, or foamed cements (Chapters 3 and 7) may be appropriate. However, when contemplating the use of ceramic or glass microspheres, one must be certain that they can withstand the hydrostatic pressure. Ceramic microspheres and most grades of glass microspheres can withstand no more than 3,000 psi [20.7 MPa], which eliminates them from consideration in most deep well completions. However, glass microspheres with hydrostatic crush strengths as high as 10,000 psi [69.0 MPa] are available. Foamed cement, occasionally used in deep high-temperature wells, is more common in geothermal and steamflood wells.

10-8 Geothermal well cementing

Projects to extract geothermal energy exist throughout the world. Virtually any location with thermal anomalies is a potential site for geothermal well drilling. Some of the more notable geothermal projects are located in California, Utah, and New Mexico, United States; Mexico; Central America; The Philippines; Indonesia; New Zealand; Kenya; Iceland; and Italy (Geothermal Education Office, 2001).

Most geothermal plants are configured as shown in Fig. 10-11. Superheated formation water that lies above the geothermal formation is produced to the surface, whereupon it is “flashed” into steam. The steam is used to power turbines that generate electrical power. The spent water is injected back into the reservoir, not for replenishment, but for environmental reasons. The formation waters are often highly saline and corrosive and contain toxic heavy metals. Another plant design, called “hot dry rock,” is employed in regions where no geothermal formation waters exist. Two intersecting wells are drilled into the hot formation. Water from the surface is pumped down one well and becomes superheated. The superheated water is then produced out of the other well and flashed into steam.

Geothermal wells are usually completed in much the same manner as conventional oil and gas wells; however, the environment with which the cements must contend is frequently much more severe. The bottomhole temperature in a geothermal well can be as high as 700°F [370°C]. The failure of wells in several geothermal fields has been directly attributed to cement failure (Radenti and Ghiringelli, 1972; Berra et al., 1998); as a result, research has been conducted to identify cement formulations that perform suitably under such conditions.
10-8.1 Well conditions associated with geothermal wells

With the exception of hot, dry rock completions with circulating temperatures as high as 500°F [260°C] (Carden et al., 1983, Duchane, 1994), most geothermal wells are not cemented under “geothermal” conditions, because the fluids circulated during drilling cool the formation. The maximum circulating temperatures during the cement job seldom exceed 240°F [116°C]; therefore, the design of cement systems with adequate thickening times is usually not a problem. Most geothermal wells are less than 10,000 ft [3,050 m] in depth. Downhole pressures are seldom above the water gradient.

The drilling programs for geothermal wells usually call for setting surface and production casing above the reservoir. In some cases, a slotted liner is hung through the producing zone, but cementing the liner is not considered critical. It is very important to cement the casings to the surface; otherwise, creep or elongation will occur because of thermal expansion when the well is brought into production (Shryock, 1984).

An economical geothermal reservoir requires that large quantities of hot water or steam must be produced from each well. Therefore, the reservoirs are usually naturally fractured and have effective permeabilities that are probably greater than 1 D. The integrity of the formations ranges from poorly consolidated to highly fractured, and the fracture gradients tend to be low. Consequently, lost circulation is the most serious obstacle to successfully cementing geothermal wells (personal communication, Weber, 2003). It is not uncommon to have losses in the casing strings set above the target reservoir; and in many cases total losses occur before the intended setting point for the intermediate string. For these reasons, low-density cement systems are required by most geothermal operators (Nelson et al., 1981).

Lost circulation also hampers the determination of cement placement temperatures. Placement temperature simulation and modeling is essential to formulate the appropriate cement system (Chapter 12).

Fig. 10-11. Geothermal power plant (from Geothermal Education Office, 2001). Drawing courtesy of Geothermal Education Office, Tiburon, California, USA.
The chemistry of the reservoir fluids varies from fresh water to brines with greater than 200,000 mg/L total dissolved solids. The fluids extracted from dry steam fields contain relatively few salts and low concentrations of noncondensible gases, the most noticeable being H₂S. The saline brines often contain significant quantities of carbonate and sulfate.

10-8.2 Performance requirements and design considerations

Geothermal wells arguably present the most severe conditions to which well cements are exposed. As a result, the performance requirements are among the most stringent. Geothermal well cements are usually designed to provide at least 1,000 psi [7.0 MPa] compressive strength, and no more than 0.1-mD water permeability (API Task Group on Cements for Geothermal Wells, 1985). In addition, the set cement often must be resistant to degradation by saline brines.

Silica-stabilized Portland cement compositions are almost exclusively used to complete geothermal wells; however, their dominance is being challenged by systems that offer better resistance to the severe chemical environments. Each is described in this section.

10-8.2.1 Portland cement–based geothermal well cement compositions

When Portland cement–based cement systems are expected to contact highly saline and corrosive geothermal brines, the particle size of the added silica is an important consideration. As explained in Chapter 3, there are two forms of silica commonly used in well cementing: silica sand, with a particle size of approximately 175–200 μm, and silica flour, with an average particle size of approximately 15 μm. Field personnel usually prefer silica sand, because its lower surface area facilitates easier slurry mixing. However, in certain geothermal environments, silica sand cannot be relied upon to provide adequate stabilization.

Eilers and Nelson (1979) investigated the effect of silica particle size on the performance of Class G cement cured in geothermal brine. The salinity of the brine was 25,000 mg/L total dissolved solids. Figure 10-12 shows the relationships between the silica particle size and several parameters—compressive strength, water permeability, and cement phase composition. The slurry density was 15.8 lbm/gal [1.90 g/cm³]. A decrease in compressive strength and an increase in water permeability occurred when the average particle size of the added silica exceeded about 15 μm. Xonotlite was also replaced by kilchoanite as the predominant cement phase.

![Figure 10-12](image.png)

Figure 10-12. Effect of silica particle size on the performance of Class G cement cured in geothermal brine (from Eilers and Nelson, 1979). Reprinted with permission of SPE.

Figure 10-13 shows that the silica particle-size effect is significantly more pronounced with lower-density cement compositions.

High concentrations of sodium chloride depress the rate at which silica enters solution (personal communication, R. Fournier, 1979); as a result, when the silica particle size is large, the rate of dissolution of silica is insufficient to allow the formation of the desired calcium...
silicate hydrates (C/S ratio < 1). The kinetics of dissolution can be affected by the particle size of the solute. Reducing the particle size of the silica increases its surface area; consequently, a sufficient supply of silica is available.

Grabowski and Gillott (1989) and Dillenbeck et al. (1990) studied the effects of silica “fume,” with an average particle size of approximately 0.1 μm (Chapter 3), upon Portland cement systems at elevated temperatures and pressures. With a constant SiO₂ concentration (40% BWOC) and water-to-solids ratio (0.5), samples were prepared containing silica fume, combinations of silica fume and silica flour, and silica flour. Curing was performed at 450°F [232°C] and 400 psi [2.75 MPa] for 7 days, using samples aged under ambient conditions for periods up to 270 days. The systems containing silica fume developed less compressive strength, but lower permeability, than equivalent systems containing only silica flour (Fig. 10-14). The major phase found in all of the samples was xonotlite (scawtite was detected in the samples containing only silica flour); however, the microstructures were different. The samples containing silica flour exhibited short parallel needles of xonotlite. As the quantity of silica fume increased, the texture of the xonotlite was granular. In general, the samples with needle-shaped xonotlite crystals exhibited higher permeabilities.

The presence of carbonate in certain geothermal brines presents a serious difficulty for Portland cement systems (Milestone et al., 1986 and 1987). Calcium silicate hydrates are not stable in such a chemical environment, even at ordinary temperatures (Taylor, 1964). Upon exposure to carbonate solutions, calcium silicate hydrates are eventually converted to a mixture of cal-

---

**Fig. 10-13.** Effect of silica particle size on the performance of a 13.5-lbm/gal Class G-perlite-bentonite system cured in geothermal brine (from Eilers and Nelson, 1979). Reprinted with permission of SPE.

**Fig. 10-14.** Compressive strength and permeability behavior of silica-stabilized Portland cements containing various amounts of silica fume (after Grabowski and Gillot, 1989). Ambient curing for 7 days at 230°C, 100% real-time humidity, and 2.75 MPa compressive strength. Reprinted with permission from Elsevier.
Cement carbonate and amorphous silica. This phenomenon has been observed in well cements by numerous researchers (Onan, 1984; Bruckdorfer, 1986; Shen and Pyle, 1989). High-alumina cements are also known to degrade in the presence of carbonate (Crammond and Currie, 1993). At present there appear to be no published data regarding the behavior of high-alumina cements in a carbonaceous environment at elevated temperatures.

The principal, and generally successful, defense against such degradation has traditionally been the placement of low-C/S-ratio cement systems with very low permeability. However, such systems have been shown to be inadequate for geothermal wells with formations containing very high concentrations of CO₂ (Hedenquest and Stewart, 1985). Milestone et al. (1986 and 1987) demonstrated that tobermorite and xonotlite are among the cement phases least resistant to carbonation, and their deterioration is accelerated when bentonite is present in the cement. Milestone et al. discovered that reducing the silica flour concentration from 35% to 20% (BWOC) improves the cement’s resistance to CO₂. When less silica is present, weaker and more permeable calcium silicate hydrates form; however, a substantial quantity of calcium hydroxide also remains in the system. Upon substantial carbonation, the calcium hydroxide reacts to form a protective layer of calcite, the permeability decreases, and further attack is inhibited.

Because of the presence of weak formations and low fracture gradients, lower-density cements are often required in geothermal wells. Therefore, research has been performed to develop low-density systems that will perform adequately. The typical extenders used to prepare low-density geothermal cements are bentonite and diatomaceous earth. Additional silica flour, up to 100% by weight of cement, is sometimes added in low-density systems to ensure proper stabilization (Gallus et al., 1979).

Ultralow-density foamed cements (Rickard, 1985; Sugama et al., 1986) and microsphere-extended systems have been used to cement geothermal wells. Such systems have been used successfully in thermal recovery wells (Section 10-9.1); however, information is sparse regarding the long-term stability of these systems to corrosive brines. Until sufficient data are available, it would be prudent to restrict the use of ultralow-density systems to applications in which the formations fluids are not aggressive.

Table 10-4 lists the compositions of both normal and low-density systems that are often used as geothermal cements. The compressive strength and water permeability upon long-term exposure to actual geothermal conditions are shown in Figs. 10-15 and 10-16, respectively.

### Table 10-4. Compositions of Typical Geothermal Cement Systems†, ‡

<table>
<thead>
<tr>
<th>Sample Code</th>
<th>Parts by Weight</th>
<th>Components</th>
<th>Slurry Weight</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>100</td>
<td>API Class G cement (64, 2C, 21.5S, 3.9A, 3.8F) [1.81 g/cm³]</td>
<td>15.1 lbm/gal [1.81 g/cm³]</td>
</tr>
<tr>
<td></td>
<td>35</td>
<td>Silica flour</td>
<td>Water</td>
</tr>
<tr>
<td></td>
<td>1</td>
<td>Lignin-sugar</td>
<td></td>
</tr>
<tr>
<td></td>
<td>54</td>
<td>Water</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>100</td>
<td>API Class J cement (37.3C, 54.2S, 1.1A, 1.0F) [1.85 g/cm³]</td>
<td>15.4 lbm/gal [1.85 g/cm³]</td>
</tr>
<tr>
<td></td>
<td>0.4</td>
<td>Lignin-sugar</td>
<td>Water</td>
</tr>
<tr>
<td></td>
<td>44</td>
<td>Water</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>100</td>
<td>API Class F cement (63.9C, 21.1S, 3.1A, 54.F)</td>
<td>15.1 lbm/gal [1.81 g/cm³]</td>
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<td>40</td>
<td>Silica flour</td>
<td>Water</td>
</tr>
<tr>
<td></td>
<td>0.7</td>
<td>Lignin-sugar</td>
<td>Water</td>
</tr>
<tr>
<td></td>
<td>63</td>
<td>Water</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>30</td>
<td>API Class J cement [1.65 g/cm³]</td>
<td>13.7 lbm/gal [1.65 g/cm³]</td>
</tr>
<tr>
<td></td>
<td>40</td>
<td>Pozzolan</td>
<td>Water</td>
</tr>
<tr>
<td></td>
<td>30</td>
<td>Blast furnace slag</td>
<td>Water</td>
</tr>
<tr>
<td></td>
<td>60</td>
<td>Carboxymethylcellulose</td>
<td>Water</td>
</tr>
<tr>
<td>5</td>
<td>100</td>
<td>API Class G cement (64.2C, 21.5S, 3.9A, 3.8F) [1.89 g/cm³]</td>
<td>13.5 lbm/gal [1.89 g/cm³]</td>
</tr>
<tr>
<td></td>
<td>35</td>
<td>Silica flour</td>
<td>Water</td>
</tr>
<tr>
<td></td>
<td>8.5</td>
<td>Perlite</td>
<td>Water</td>
</tr>
<tr>
<td></td>
<td>2</td>
<td>Bentonite</td>
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<td>Lignin-sugar</td>
<td>Water</td>
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<td></td>
<td>116</td>
<td>Water</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>100</td>
<td>API Class G cement (64.2C, 21.5S, 3.9A, 3.8F) [1.86 g/cm³]</td>
<td>14.0 lbm/gal [1.86 g/cm³]</td>
</tr>
<tr>
<td></td>
<td>35</td>
<td>Silica flour</td>
<td>Water</td>
</tr>
<tr>
<td></td>
<td>10</td>
<td>Diatomaceous earth</td>
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<td>1</td>
<td>Lignin-sugar</td>
<td>Water</td>
</tr>
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<td>91</td>
<td>Water</td>
<td></td>
</tr>
<tr>
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<td>15.5 lbm/gal [1.86 g/cm³]</td>
</tr>
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<td></td>
<td>40</td>
<td>Silica flour</td>
<td>Water</td>
</tr>
<tr>
<td></td>
<td>0.8</td>
<td>Dispersant</td>
<td>Water</td>
</tr>
<tr>
<td></td>
<td>0.8</td>
<td>Fluid-loss agent</td>
<td>Water</td>
</tr>
<tr>
<td></td>
<td>0.4</td>
<td>Retarder</td>
<td>Water</td>
</tr>
<tr>
<td></td>
<td>60.3</td>
<td>Water</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>100</td>
<td>API Class G cement [1.63 g/cm³]</td>
<td>13.6 lbm/gal [1.63 g/cm³]</td>
</tr>
<tr>
<td></td>
<td>100</td>
<td>Silica flour</td>
<td>Water</td>
</tr>
<tr>
<td></td>
<td>0.3</td>
<td>Retarder</td>
<td>Water</td>
</tr>
<tr>
<td></td>
<td>85.1</td>
<td>Water</td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>100</td>
<td>API Class G cement (64.2C, 21.5S, 3.9A, 3.8F) [1.85 g/cm³]</td>
<td>15.4 lbm/gal [1.85 g/cm³]</td>
</tr>
<tr>
<td></td>
<td>80</td>
<td>Silica flour</td>
<td>Water</td>
</tr>
<tr>
<td></td>
<td>0.5</td>
<td>Fluid-loss agent</td>
<td>Water</td>
</tr>
<tr>
<td></td>
<td>0.3</td>
<td>Retarder</td>
<td>Water</td>
</tr>
<tr>
<td></td>
<td>76.8</td>
<td>Water</td>
<td></td>
</tr>
<tr>
<td>10</td>
<td>100</td>
<td>API Class G cement (64.2C, 21.5S, 3.9A, 3.8F) [1.89 g/cm³]</td>
<td>15.7 lbm/gal [1.89 g/cm³]</td>
</tr>
<tr>
<td></td>
<td>40</td>
<td>Silica flour</td>
<td>Water</td>
</tr>
<tr>
<td></td>
<td>1</td>
<td>Retarder</td>
<td>Water</td>
</tr>
<tr>
<td></td>
<td>59.2</td>
<td>Water</td>
<td></td>
</tr>
</tbody>
</table>

† from API Task Group on Geothermal Well Cements, 1985. Reprinted with permission from Oil & Gas Journal.
‡ A = Al₂O₃, C = CaO, F = Fe₂O₃, M = MgO, S = SiO₂.
Compressive strength performance of typical geothermal well cements under actual conditions (from API Task Force on Geothermal Well Cements, 1985). Reprinted with permission from Oil & Gas Journal.

**Fig. 10-15.** Compressive strength performance of typical geothermal well cements under actual conditions (from API Task Force on Geothermal Well Cements, 1985). Reprinted with permission from Oil & Gas Journal.

Water permeabilities of cement samples taken from slurry-filled sandstone cup holders after curing 1 day and 3, 6, and 12 months downhole in the Cerro Prieto geothermal field, Mexico. The downhole temperature was 417°F [214°C].

**Fig. 10-16.** Permeability performance of typical geothermal well cements under actual conditions (from API Task Force on Geothermal Well Cements, 1985). Reprinted with permission from Oil & Gas Journal.
10-8.2.2 Alternate geothermal well cement compositions

More recently, calcium phosphate and calcium aluminosilicate systems were developed specifically for use in geothermal wells, and both show superior resistance to CO₂. The chemistries of each system are described earlier in this chapter.

Calcium phosphate systems (Section 10-6) have been used since 1997 to successfully cement geothermal wells in Japan and Indonesia, and service life is estimated to be about 20 years (Weber et al., 1998; Brookhaven National Laboratory, 2000). The cement blends consist of fly ash, calcium aluminate cement, sodium polyphosphate, and water in compositions that vary with the depth at which the cement will be used.

Calcium aluminosilicate systems (Section 10-5) were developed more recently (Barlet-Gouédard and Vidick, 2001; Barlet-Gouédard and Goffé, 2002). At this writing, the performance of these systems in actual wells has not been published.

Placing cements that are chemically inert to corrosive geothermal brines would be an attractive strategy. Such systems, commonly referred to as “synthetic cements,” are used routinely to complete wells for CO₂-flooding projects or chemical waste disposal (Chapter 7). Epoxy-based polymer systems are most commonly used for such applications; unfortunately, they would suffer thermal degradation at the temperatures encountered in geothermal reservoirs. However, epoxy cements are often used near the surface, because they can withstand the temperature cycling associated with geothermal well production.

Polymers that are stable to high temperatures have been examined by various researchers. Zeldin and Kukacka (1980) developed an organosiloxane polymer cement that was proven suitable as a geothermal cement in an API study. A coal-filled furfuryl alcohol-base cement system for geothermal wells was proposed by Pettit (1979) and Eilers (1985). Degouy and Martin (1993) demonstrated that phenolic resins, with fillers such as calcium carbonate and sand, provided acceptable performance at curing temperatures up to 330°F [200°C]. No commercial use of these technologies has been reported.

10-9 Thermal recovery wells

The application of heat to stimulate heavy oil production has been practiced for more than 50 years. Methods such as in situ combustion (fireflood), downhole heaters, hot fluid injection, and steam stimulation have been used. In situ combustion and steam injection are the most common methods practiced today. These techniques have been the salvation of many oil fields with high-viscosity crudes, and essentially involve the trading of heat for viscosity reduction (Kastrop, 1965; Butler, 1991).

As in geothermal wells, the formations associated with steam recovery and fireflood wells are frequently problematic. Weak and unconsolidated zones with low fracture pressures and high permeability are often present; as a result, severe lost circulation and fluid-loss problems are common.

Thermal recovery wells are usually less than 3,000 ft [915 m] in depth and are frequently deviated (30° to horizontal). The circulating temperatures during primary cementing operations are often less than 104°F [40°C], and accelerators such as calcium chloride or sodium chloride are often added to promote early cement strength development.

Thermal recovery wells are always cemented to surface. When heat is initially supplied, the temperature rise should be controlled to prevent undue thermal shock to the casing and cement. Nevertheless, because of thermal expansion, high levels of stress are built up in the pipe and the cement sheath (Carter et al., 1966); therefore, the strongest possible cement-to-pipe and cement-to-formation bonds are necessary. Failure of the bonds could allow interzonal communication and pipe expansion. The ultimate result would be casing failure by buckling or telescoping (Humphrey, 1960). A substantial amount of work has been performed to devise cementing techniques that minimize the effects of thermal expansion. Such methods include the placement of thermal packers (Smith, 1966) and the inclusion of a sliding sleeve in the casing string that can move freely in response to thermal stress (Greer and Shryock, 1967). A third procedure involves holding the casing in tension during the cement job to minimize the expansion when thermal stress is eventually applied (Farouq Ali and Moldau, 1979).

The cement must also be able to withstand the elevated temperature exposure and thermal cycling associated with steamflood and fireflood wells. To maximize the delivery of heat to the pay zones, an insulating cement is desirable in thermal recovery wells; however, the presence of such cements places additional thermal stress on the casing (Leutwyler, 1966). Thermal conductivity is more dependent upon the cement density than cement composition (Nelson, 1986). Typical laboratory data are shown in Fig. 10-17. At equivalent density, the thermal conductivity of foamed cement is only marginally different from that of conventionally extended cement.
10-9.1 Steam recovery wells

Enhanced oil recovery may be accomplished by steamflooding or cyclic steam stimulation (Gates and Holmes, 1967; Curtis et al., 2002). Steamflooding consists of introducing steam into an injection well and sending the steam through the formation to a production well. Cyclic steam stimulation of production wells involves the injection of steam into the production well for a short period of time and returning the well to production (Earlougher, 1968). Steam recovery techniques are practiced extensively throughout the world (Chu, 1983). During the last decade, the steam-assisted gravity drainage (SAGD) method for recovering heavy crudes has been extensively developed (Butler, 1998 and 2001). The process uses twin horizontal wells drilled and extended into the base of a reservoir with the horizontal steam injector placed directly above the horizontal production well (Fig. 10-18). In an ideal SAGD process, a growing steam chamber forms around the horizontal injector, and steam flows continuously to the perimeter of the chamber, where it condenses and heats the surrounding oil. As the viscosity of the oil decreases, it drains to the horizontal production well underneath. Thus, the use of gravity increases the efficiency of oil production.

The most important steamflood fields are located in central and southern California, United States; Alberta and Saskatchewan, Canada; Venezuela; The Netherlands; West Germany; and Indonesia. Reservoir temperatures seldom exceed 600°F [315°C]; therefore, Portland cement is used in virtually all steamflood well completions.

The characteristics of steamflood wells and the associated performance requirements of cementing materials are often at cross-purposes. A strong cement with low permeability is required, and normal- to high-density slurries are best at providing these qualities. Unfortunately, because of the lost circulation and thermal conductivity considerations, such slurries are generally unsuitable. Therefore, much research has been performed to devise low-density slurries with high compressive strength and low permeability.

Conventionally extended Portland cement systems, containing perlite, bentonite, diatomaceous earth, etc., generally perform adequately in steamflood wells, provided the slurry density is above 12.5 lbm/gal [1.5 g/cm³]. Their long-term performance is very similar to that exhibited by such systems in deep wells (Fig. 10-19).

The formations in steamflood wells are often so incompetent that cement systems with densities less than 12.5 lbm/gal [1.5 g/cm³] are required to avoid lost circulation or formation damage. Thus, silica-stabilized foamed cements (Smith, 1983) and microsphere-extended systems (Ripley et al., 1980) are very common in steamflood well completions today. Previously, multi-stage cementing was necessary to successfully complete these wells.
Typical slurries using glass or ceramic microspheres are prepared with a silica-stabilized Portland cement–based slurry. The long-term performance of glass microsphere systems cured at 450° and 600°F [232° and 315°C] is shown in Fig. 10-19. The slurry densities vary from 10.0 to 12.0 lbm/gal [1.20 to 1.45 g/cm³].

The performance of silica-stabilized ceramic microsphere systems at 450° and 600°F [232° and 315°C] is shown in Fig. 10-20. Initially, these systems were generally stronger and less permeable than their glass microsphere counterparts. However, between 1 and 2 years of curing, significant deterioration was noted at both temperatures (unpublished data, Nelson, 1987). X-ray diffraction analysis of the systems revealed the coincident appearance of reyerite and certain aluminosilicate hydrate phases. Ceramic microspheres are derived from fly ashes, and the delayed (reyerite-related) deterioration of normal-density fly ash cement systems has been discussed earlier in this chapter.

Typical foamed cement systems for thermal wells are prepared from a normal-density base slurry of Portland cement, at least 35% silica flour, a surfactant, and a foam stabilizer. The long-term performance at 450° and 600°F [232° and 315°C] of three foamed cement systems is shown in Fig. 10-21.
with densities ranging from 9.0 to 12.0 lbm/gal [1.08 to 1.44 g/cm³] is shown in Fig. 10-21. Comparison of the foamed cement data with those of equal-density microsphere systems reveals the foams to have significantly higher compressive strength. The water permeabilities of the foamed cements are also higher (>0.1 mD), and more variable with curing time.

Foamed cements have also been shown to resist repetitive thermal cycling, which occurs when the cyclic steam stimulation technique is applied (Harms and Febus, 1984). Compressive strength and permeability data for systems cycled between 550°C and 100°F [288°C and 94°C] are shown in Table 10-5. More recently, thermal cements containing additives that impart flexibility (Chapter 7) have been successfully introduced for steamflood applications (Stiles and Hollies, 2002; Stiles, 2006).
In situ combustion recovery, or fireflood, consists of initiating combustion in an injection well and then propagating the combustion front by the injection of air or oxygen through the reservoir to the production wells (Chu, 1981; Petit et al., 1992). In such wells, the cement is exposed to maximum temperatures between 700° and 1,700°F [371° and 926°C] near the burning zone. Such temperatures exceed the stable range of Portland cement; therefore, high-alumina cement is necessary.

Fireflood wells are physically similar to and are usually found in the same locations as steam injection wells. Thus, the formation conditions and cement performance requirements are basically the same. Usually, most of the casing is cemented with Portland cement systems, with calcium aluminate cement placed opposite and about

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**Table 10-5. Effect of Thermal Cycling on Performance of Foamed Cements for Steamflood Conditions**

<table>
<thead>
<tr>
<th>Properties of Foamed Cement</th>
<th>Foamed Cement Density</th>
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</thead>
<tbody>
<tr>
<td></td>
<td>10 lbm/gal</td>
</tr>
<tr>
<td>Compressive strength after 20 days at 550°F</td>
<td>1,210 psi</td>
</tr>
<tr>
<td>Compressive strength after 100 days at 550°F&lt;sup&gt;2&lt;/sup&gt;</td>
<td>1,630 psi</td>
</tr>
<tr>
<td>Compressive strength after 160 days at 550°F&lt;sup&gt;3&lt;/sup&gt;</td>
<td>1,240 psi</td>
</tr>
<tr>
<td>Air permeability after 100 days</td>
<td>2.4 mD</td>
</tr>
</tbody>
</table>

---

<sup>1</sup> Surface slurry: 15.4 lbm/gal Class G, 40% silica flour, 3% lime (from Harms and Febus, 1984). Reprinted with permission of SPE.

<sup>2</sup> Cycled to 100°F twice.

<sup>3</sup> Cycled to 100°F three times.

---

**Fig. 10-21.** Long-term performance of foamed cement systems cured at elevated temperatures.

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**10-9.2 In situ combustion wells**

In situ combustion recovery, or fireflood, consists of initiating combustion in an injection well and then propagating the combustion front by the injection of air or oxygen through the reservoir to the production wells (Chu, 1981; Petit et al., 1992). In such wells, the cement is exposed to maximum temperatures between 700° and 1,700°F [371° and 926°C] near the burning zone. Such temperatures exceed the stable range of Portland cement; therefore, high-alumina cement is necessary.

Fireflood wells are physically similar to and are usually found in the same locations as steam injection wells. Thus, the formation conditions and cement performance requirements are basically the same. Usually, most of the casing is cemented with Portland cement systems, with calcium aluminate cement placed opposite and about
100 ft [31 m] above the pay zone as a tail slurry. However, this practice is not without risk. Calcium aluminate cement is a strong accelerator of Portland cement, and setting can occur within a few minutes after the two slurries commingle in the annulus. For complete safety, calcium aluminate cement should be the only system pumped.

The performance of two normal-density calcium aluminate cement systems is depicted in Fig. 10-22. Data are given for systems cured at 100° and 220°F [38° and 93°C] and heated in a refractory furnace at 600°, 1,000°, and 1,500°F [315°, 538°, and 815°C]. The compressive strengths of the aluminate systems at the lower temperatures are adequate, yet considerably lower than similar-density Portland cement systems. This is primarily because of the previously described conversion of the initial aluminate hydrates to C₃AH₆. The water-permeability values are extremely low as well.

The performance of foamed calcium aluminate cements has also been investigated (Nelson and Eilers, 1985). Figure 10-23 shows the compressive strength and water permeability of three systems cured for 7 and 28 days at 1,250°F [677°C] in a refractory furnace. Two foams, with densities of 11.0 and 9.0 lbm/gal [1.32 and 1.08 g/cm³] were prepared from a neat calcium aluminate cement-based slurry. Another foam, with a density of 11.0 lbm/gal [1.32 g/cm³], contained fly ash. The compressive strength was adequate; however, the water permeabilities were excessive.

![Fig. 10-22. Compressive strength and permeability performance of calcium aluminate cement systems at various temperatures (from Nelson and Eilers, 1985). Reprinted with permission from the Petroleum Society of CIM.](image-url)
10-10 Conclusion

The preceding discussion has demonstrated that thermal cements encompass a wide variety of wellbore conditions and complex chemical processes. Many factors must be considered to determine the optimum cement composition for a particular situation. Nevertheless, there are several basic points that the engineer should remember when contemplating this problem.

- When static temperatures exceed 230°F [110°C], 35% to 40% silica BWOC must be added to Portland cements; otherwise, strength retrogression will occur.
- If saline geothermal brines are present, fine silica flour (less than 15-μm particle size) should be added to Portland cement as a stabilizer. Silica sand does not reliably provide adequate protection.
- If high concentrations of CO₂ are present, using calcium aluminosilicate or calcium phosphate cements is recommended. If Portland cement is used, degradation can be inhibited by reducing the silica concentration to 20% BWOC.
- Most common cement extenders are compatible with thermal cements; however, if the static temperature exceeds 450°F [232°C], fly ash should not be used in Portland or Class J cement systems. Bentonite, perlite, and diatomaceous earth are suitable.
- Microsphere cement systems can be used in thermal wells, provided the base slurry is stabilized to high temperatures, and the collapse pressure (usually 3,000 psi or 20.7 MPa) is not exceeded.
- Foamed cement, made from a stabilized base slurry, can be used with confidence in most thermal wells. In geothermal wells, in which corrosive fluids are produced, the long-term stability of foamed cements has not been proven.
- If the cement will be exposed to temperatures exceeding 750°F [400°C], Portland cement should not be used. High-alumina cement is suitable.
- Silica is deleterious to the stability of high-alumina cements at temperatures exceeding 572°F [300°C]. Crushed aluminosilicate firebrick or fly ash is suitable.
- During laboratory testing, accurate static and circulating temperatures must be used to obtain an optimal thickening time and compressive strength at the wellsite.
High pressure strongly affects the behavior of thermal cement systems; therefore, laboratory testing must be performed at the anticipated bottomhole pressure.

Thermal cements are sensitive to subtle chemical changes; therefore, laboratory testing should always be performed with samples of the cement, additives, and location water that will be used during the job.

The common assumption that high compressive strength is automatically linked with low permeability is false. Permeability should be measured in the laboratory before a cement system is placed in a thermal well.

10-11 Acronym list

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>API</td>
<td>American Petroleum Institute</td>
</tr>
<tr>
<td>ASTM</td>
<td>ASTM International, formerly the American Society for Testing and Materials</td>
</tr>
<tr>
<td>BHCT</td>
<td>Bottomhole circulating temperature</td>
</tr>
<tr>
<td>BHST</td>
<td>Bottomhole static temperature</td>
</tr>
<tr>
<td>BSC</td>
<td>Belite-silicate cement</td>
</tr>
<tr>
<td>BWOC</td>
<td>By weight of cement</td>
</tr>
<tr>
<td>C/S</td>
<td>Bulk lime-to-silica (ratio)</td>
</tr>
<tr>
<td>CA</td>
<td>Monocalcium aluminate</td>
</tr>
<tr>
<td>CH</td>
<td>Calcium hydroxide</td>
</tr>
<tr>
<td>C-S-H</td>
<td>Calcium silicate hydrate</td>
</tr>
<tr>
<td>SAGD</td>
<td>Steam-assisted gravity drainage</td>
</tr>
<tr>
<td>WOC</td>
<td>waiting on cement</td>
</tr>
</tbody>
</table>
11-1 Cementing materials

Before describing the design and function of cementing equipment, one must be familiar with the physical and chemical properties of the various cementing materials. A thorough discussion is presented in Chapters 2 and 3; however, a rapid review of the principal points is useful for this discussion.

11-1.1 Cement

As discussed in Chapter 2, Portland cement is used during almost all well cementing operations. It is a finely divided and highly reactive powder. The vigorous hydration of Portland cement during initial mixing, as well as the changeable slurry properties during placement, complicate the design of cement mixing and pumping equipment.

Portland cement is usually stored in silos at a central storage location. Alternatively, it may be packaged in U.S. (94 lbm) or SI (50 kg) sacks, so-called “big bags” (1 to 1.5 SI tons generally), or larger quantities (truck, railway car, or ship).

11-1.2 Water

Fresh water is normally used for cementing onshore wells and seawater for offshore locations. However, one must be aware that fresh waters are often not very “fresh.” Inorganic salts and organic residues from vegetation are frequently present in significant quantities. Such materials are known to affect the performance of Portland cement systems.

11-1.3 Dry cement additives

Table 11-1 summarizes the relevant properties of dry additives with regard to cementing equipment and logistics.

<table>
<thead>
<tr>
<th>Material</th>
<th>Chemically Inert</th>
<th>Chemically Active</th>
</tr>
</thead>
<tbody>
<tr>
<td>Form</td>
<td>Insoluble powder or finely cut material</td>
<td>Soluble powder or finely cut material</td>
</tr>
<tr>
<td>Examples (function)</td>
<td>Powdered coal (extender)</td>
<td>Lignosulfonate (retarder)</td>
</tr>
<tr>
<td></td>
<td>Hematite (weighting agent)</td>
<td>Sodium silicate (extender)</td>
</tr>
<tr>
<td></td>
<td>Barite (weighting agent)</td>
<td>Calcium chloride (accelerator)</td>
</tr>
<tr>
<td>Maximum concentration (order of magnitude)</td>
<td>100% (BWOC)</td>
<td>10% (BWOC)</td>
</tr>
<tr>
<td>Influence of accuracy in concentration on slurry quality</td>
<td>Concentration acts directly on system density; no unexpected effect.</td>
<td>Materials may have secondary effects.</td>
</tr>
<tr>
<td>Handling</td>
<td>The additives are blended with the dry cement in a special blender at the central storage location up to several days before the pumping job. The blended material is then transported to the wellsite. (If the amount required is small and the material easily scattered in the water, it is treated as a soluble material.)</td>
<td>The additives are normally dry-blended with the cement. They are sometimes added to mix water on location in an open horizontal tank, just prior to the job.</td>
</tr>
</tbody>
</table>
11-1.4 Liquid cement additives

Offshore, liquid additives are usually preferred. Such materials are more compatible logistically, because their mixing requires less space. Because liquid additives are preblended with the mix water, the resultant slurry tends to be more homogeneous than one mixed from a dry-blended powder mixture. Table 11-2 is a summary of the relevant points.

11-2 Basic equipment

Figure 11-1 is a schematic flow diagram of cement-slurry preparation that indicates the steps performed at the central storage location and at the wellsite. Each function in the flow diagram also represents a major piece of equipment. Some functions may be combined into a multipurpose “cementing unit.” In the following discussion, the design and operation of each class of equipment are presented in detail.

11-2.1 Cement and dry additive blending

Figure 11-2 is an overview of the delivery and blending processes that occur at the central storage location. Cement is delivered to the central storage location. Upon delivery in bags, the cement is usually combined. Equipment that may be used in the transfer includes pneumatic loading bottles (Fig. 11-3), mechanical screw elevators, or combined systems (for unloading from ships). These transfer systems may also be used to load dry additives.

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**Table 11-2. Important Properties of Liquid Additives with Respect to Cementing Logistics**

<table>
<thead>
<tr>
<th>Type of material</th>
<th>All liquid additives are chemically active. Frequently, they are water solutions of the corresponding dry additive.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Examples (function)</td>
<td>Lignosulfonate solution (retarder) Naphthalene sulfonate solution (dispersant) Latex (gas migration prevention)</td>
</tr>
<tr>
<td>Concentration (order of magnitude)</td>
<td>Up to 25 L/100 kg cement (3.0 gal/U.S. sack)</td>
</tr>
<tr>
<td>Influence of accuracy in concentration on slurry quality</td>
<td>Materials may have detrimental secondary effects.</td>
</tr>
<tr>
<td>Handling</td>
<td>Additives are blended with the mix water on location in a horizontal open tank, shortly before the job. They also can be blended on the fly during the job. The second method is preferred.</td>
</tr>
<tr>
<td>Localization</td>
<td>Mainly offshore</td>
</tr>
</tbody>
</table>

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Fig. 11-1. Typical cementing process.
The bulk cement is stored in pneumatic or atmospheric silos. Transfer systems are available to move the cement from one silo to another or to a blender, road transport unit, or supply boat. When the transfer system is pneumatic, several silos are connected permanently to save time and labor. In humid climates, an air dryer may be installed in the system.

The cement and dry additives are usually combined in a pneumatic blending tank (10- to 20-ton capacity) at the central bulk material plant (Fig. 11-4). Bulk materials are usually air-blown, and sacked materials are poured into the tank through a hopper located on top. The sacked additives may also be poured into pneumatic additive bottles (1- or 2-ton capacity) and then blown into the blending tank. Pressurized air is supplied by one or more air compressor units.

The bulk materials are loaded into the blending tank first for weighing purposes. A weigh cell is permanently integrated into the tank frame. The sacked additives are loaded last. Air, pressurized to about 35 psi [2.5 bar], is injected through nozzles into the mass of the materials until thorough blending is accomplished. Then the blend is transferred pneumatically to a bulk material transport container for delivery to the wellsite. To obtain the required amount of cementing materials, more than one batch must frequently be prepared.
Although very popular, this method has two drawbacks.

- Some particle segregation (caused by shaking) can take place during transportation to the rig site, especially if the distance is long and the road surface is rough (e.g., corrugated desert track). This problem is magnified if the blended materials have significantly different particle sizes or densities. If small quantities of soluble or easily dispersible additives are needed, mixing the dry additives with water at the rig site is often preferred.

- If the cement job is canceled or postponed for a long period after the blend has been prepared, a storage or reuse problem may arise. Adding liquid additives only during the job prevents such situations because shelf life problems are eliminated.

11-2.2 Transportation of bulk materials or blends to the wellsite

The equipment used to deliver the cementing materials to the wellsite varies according to the location. The various types of transports are discussed below.

**Land rigs:** Trucks or semitrailer transports are generally used for land operations. As shown in Fig. 11-5, truck-mounted vertical tanks or semitrailer-mounted vertical or horizontal tanks are the most common.

**Limited access locations:** Cementing materials in sacks or big bags can be transported to remote locations by truck, cargo plane, barge, ship, or helicopter. The con-
tainers are made of durable, water-resistant materials. Sometimes, the containers are placed in stackable crates for added protection.

**Offshore rigs:** Supply boats or cementing vessels are used for offshore locations. They normally have built-in tanks, pneumatic unloading equipment, and a supply of hoses. Sometimes, mobile skid-mounted tanks with a low center of gravity and mobile unloading equipment are used. It is important to note that the pneumatic equipment must be sufficiently powerful to blow heavy materials such as barite (specific gravity of 4.33) up to the drilling rig tanks, a vertical distance of 130 to 200 ft [40 to 60 m]. The air compressors used for this task typically deliver 250 to 350 ft³/min [7,100 to 9,900 L/min] with a pressure rating of 28 to 44 psi [2 to 3 bar].

### 11-2.3 Wellsite storage of cement or blends

As discussed above, pneumatic bulk trucks or trailers transport neat or preblended dry cement to the wellsite from the central storage and blending plant. Neat cement can also arrive directly from the cement mill. The material is then transferred pneumatically to transportable tanks that are either brought to the rig site for the cement job or are a permanent part of the drilling rig equipment. Such tanks are similar to those used at central storage locations, but their dimensions allow transport on standard or specially designed (with a built-in hydraulic laying/raising system) trailers. When empty, the tanks must not exceed the weight limits specified by various countries. A large variety of storage tanks for road travel exists within two principal categories—atmospheric and pressurized. Both are equipped with a set of skids for proper installation on imperfectly leveled ground and for easy winching onto trailers.

The atmospheric tank is always operated in a vertical position. Air at low pressure (about 3 psi [0.2 bar]) is blown into a gutter fixed to the slanted bottom of the tank. The roof of the gutter is made of a porous material. The air passes through the porous partition and fluidizes the cement blend. The cement blend glides along the slanted bottom to a chute gate and then to the hopper of a slurry mixing system. As illustrated in Fig. 11-6, atmospheric tanks are made in the shape of a parallelepiped.

Pressurized tanks use air at about 44 psi [3 bar] pressure and can operate horizontally or vertically. Figure 11-7 is a schematic diagram of a typical unit. As shown in Fig. 11-8, the vertical tanks are generally cylin-droconical in shape, while horizontal models are more complex. In the first stage, pressure-reduced air is blown from the bottom through the mass of cement for aeration and fluidization. Then air at 44 psi [3 bar] is injected into the tank, and the cement flows out through a discharge line to a surge tank, which feeds the cement mixer. For versatility, some vertical pressurized tanks are also equipped to release the cement directly to a hopper at atmospheric pressure (Fig. 11-9).

The bulk trailers are sometimes used for additional storage. Indeed, they can serve all storage needs on the rig site, provided they are equipped with their own surge tanks, described later.
11-2.4 Metering of water

Contrary to what one might think, the simple method of employing a flowmeter is not used for water metering. A set of twin 10-bbl (or sometimes 20-bbl) tanks is preferred. A “displacement tank” (Fig. 11-10), which is divided equally by a partition, is also used.

Both sides of the partitioned tank are filled with mix water from the rig storage. If the job is offshore, the freshwater or seawater distribution system is used. Each batch of mix water is then used successively to feed the cement mixer.

The additives may be preblended with the water in the storage tanks or may be blended while the water is passing through the displacement tank. In the second case, a liquid-additive metering system (described later) is required.
For precise placement of the slurry in the wellbore, the volume of the displacement fluid must be accurately measured. After the cement slurry has passed through the mixing system, the displacement fluid usually passes through the displacement tanks for volume measurement and is pumped by the cementing unit instead of the rig's mud pumps.

11-2.5 Liquid additive storage and mixing

The simplest method of mixing liquid additives (and dry additives at less than 3% by weight of cement) with water consists of pouring the required amount of each additive into a tank of water. One should measure the additives and water accurately to obtain the correct concentration; the preparation of a slight excess of solution is also advisable. The mixing can be achieved with a paddle mixer, circulation pump, jetting system, or a combination of these.

The premix method has several disadvantages. Premixing requires an extra tank, which must be clean and sufficiently large. Extra tanks are not always available, and sufficient space to accommodate them may not exist on the rig site, especially offshore. If the job is canceled or postponed, the costly solution may have to be thrown away. Also, if a larger-than-expected volume of slurry becomes necessary during the job, the volume of the premixed additive solution may be inadequate. Thus, methods that allow continuous ("on-the-fly") mixing are often preferred. On-the-fly methods employ a semimanual or automatic metering system that delivers the correct amount of additives to each side of the displacement tank.

11-2.5.1 Liquid additive metering system with metering tanks

All liquid-additive metering systems consist of two principal parts—a storage and transfer unit and a metering unit.

The storage/transfer unit generally includes four storage tanks of various capacities (usually between 6.2 and 25 bbl [1,000 and 4,000 L]). The storage and transfer unit allows the independent metering of additives according to the requirements of a particular job. This is convenient because well cement slurries typically contain two or three additives.

Each storage tank is equipped with its own air-operated diaphragm pump and agitation system (recirculation, as illustrated in Fig. 11-11, or air-operated stirrer) to avoid segregation of the additive components. Therefore the operation of the unit requires a source of clean and dry air at 120 to 145 psi [8 to 10 bar]. The configuration of the unit varies depending on whether it is designed for use on land (skid or trailer-mounted) or offshore (containerized).

The metering unit generally consists of a set of three (Fig. 11-11) or four 25-gal or 10-L tanks, with visible level scales. To prepare a batch (10 bbl or 20 bbl [1.6 m³ or 3.18 m³] according to the displacement tank), the proper amounts of the selected additives are introduced into the metering tanks. The additives are then released into one of the two displacement-tank sections that is being filled with water. Finally, the mixture is agitated to obtain a homogeneous solution. The same operation is repeated for the following batch in the other half of the displacement tank and so on. The repetitions of the operation may be automatically or semiautomatically controlled.
11-2.5.2 Liquid-additive metering system without metering tanks

The liquid-additive-system metering rack (Fig. 11-12) is used to provide accurate (±2%) delivery of up to four additives into displacement tanks. The operator depresses a button to initiate the delivery. The metering rack behaves as four “smart valves,” installed between the additive pumps and the displacement tanks. The valves are controlled by a microcomputer using data from electromagnetic flowmeters.

11-2.6 Surge tanks

For smooth cement mixer operation, the supply of cement (or blend) should be steady, and the pressure at the mixer bowl should remain constant. The bulk cement is moved from the storage tank toward the cement mixer, driven by the differential pressure created between the tank and the end of the line. If the line is longer than approximately 23 ft [7 m], the cement tends to separate from the conveying air into slugs, creating pulsating flow. To smooth the flow and allow for operational requirements, such as changing from one storage tank to another, a surge tank is used.

As shown in Fig. 11-13, the surge tank has a cylindroconical shape. It has a capacity of about 12.5 bbl [2,000 L] and connects the end of the transfer line to the top of the mixer bowl. This device maintains the pressure above the mixer bowl at atmospheric level plus the hydrostatic head of the material. A dust separator is also installed where the conveying air is vented to the atmosphere.

In some cases, the surge tank is maintained at higher than atmospheric pressure. The advantage is a higher delivery rate to the cement mixer, but the drawback is a higher required pressure from the bulk system to feed the surge tank. A pressurized surge tank is also used.
with certain types of recirculating cement mixers to maintain a steady delivery rate. The tank is pressurized by controlling the flow or air in the vent line. This type of surge tank is used almost exclusively offshore, where the bulk system is required to transport the cement long distances.

11-2.7 Cement mixing

The cement mixer is a device in which a flow of pressurized water (possibly containing additives) meets a flow of cement (possibly containing additives), and a cement slurry is formed at a prescribed rate. Several types of mixing systems exist; they are described individually below.

11-2.7.1 Conventional jet mixer

The conventional jet mixer consists of a hopper, a mixing bowl, a discharge gooseneck, and a slurry tub. The maximum slurry-generating capacity of the conventional jet mixer, evaluated in rate of dry material, is slightly higher than 2,200 lbm/min (1 SI ton/min). Figure 11-14 shows a configuration for sacked cement, and a system for pneumatically delivered cement is illustrated in Fig. 11-15.

The cement is delivered to the hopper. The water is injected into the bowl through jets for mixing with the cement and into the gooseneck for adjusting the slurry density. The jets are chosen according to the operating pressure, slurry fabrication rate, and type of dry materials. The movement of cement down through the hopper is assisted by the high-pressure flow of water through the jets. The resulting pressure drop pulls the dry cement into the stream of water. To reinforce this effect, the gooseneck can be given a venturi tube profile. Further along at the gooseneck, turbulent flow mixes the cement particles with the water, and the result is a cement slurry.
The slurry density is adjusted by using the bypass system to change the water-to-cement ratio. As the bypass is opened, the suction effect decreases and reduces the amount of cement drawn out of the hopper. At the same time, the water bypassing the jets enters the slurry. The combined effect is a decrease in slurry density. Conversely, if the bypass is closed, the density increases.

The conventional jet mixer can be operated at low (175 to 200 psi [12 to 14 bar]) or high (880 to 1,180 psi [60 to 80 bar]) water pressure. In the first case, the mixer pump is a centrifugal pump. In the latter case, it is a reciprocating pump, usually identical (except perhaps in plunger size) to the displacement pump. The “double high-pressure pump cementing units,” which are the most widely used throughout the world, are equipped to mix at either low or high pressure. The low-pressure method is preferred for two main reasons. Less horsepower is required and, because both high-pressure pumps are available to displace the slurry, higher mixing and displacement rates are possible. With the high-pressure method, the jets and the bowl-and-gooseneck assembly are less apt to become plugged with dirty mixing water or poor-quality cement.

**11-2.7.2 Recirculation jet mixer**

The maximum capacity of the recirculation jet mixer (Fig. 11-16) is slightly more than 4,400 lbm/min (2 SI ton/min). The recirculation jet mixer differs from the conventional type in several ways.

- A remotely controlled sliding gate is present between the hopper and the bowl.
- The slurry density is adjusted by operating the sliding gate.
- The slurry is removed from the slurry tub by a recirculation jet, fed by a centrifugal pump. The centrifugal pump force feeds the displacement pumps and recirculates some slurry through the mixing system.
- Water is always injected ahead of the recirculation jet.

Recirculation through the mixer heart and the tub improves the homogeneity and rheology of the slurry. Adjustment of the slurry density is also easier.

**11-2.7.3 Recirculation mixer without conventional jets**

Available equipment includes a variety of mixers without conventional jets (Fig. 11-17). The maximum capacity of most mixers, evaluated by rate of dry material, is close to 4,400 lbm/min [2 SI tons/min]. They all consist of the following.

- A sophisticated metering system to mix cement with water and a device to mix the resulting slurry with previously mixed slurry from the mixing tub
- A centrifugal pump or similar device (located at the bottom of the tub) to improve the initial mixing by shearing, ensure recirculation through the mixer, and feed pressurized slurry to the downhole pump
- A mixing tub that can be divided into two sections, each of which can be equipped with a stirrer to improve mixing, allowing a film-like flow over the common partition that assists the release of entrapped air
Depending on the model, the density of the slurry is remotely controlled by metering the cement and/or water. The water rate is usually kept constant, and the slurry density is controlled by altering the rate at which cement is delivered to the mixer. Normally, the cement is transferred directly from a pressurized tank without passing through a surge tank.

Fig. 11-16. Recirculation jet mixer.

Fig. 11-17. Recirculation jet mixer (without jets).
11-2.7.4 Cement mixing units

As discussed above, the batch-blending system and the liquid-additive metering system have been designed to solve the proportioning problems encountered with cementing materials. However, the slurry properties are affected not only by the proportions of cement, water, and additives, but also by the shearing that occurs during mixing.

Proper operation of a mixing unit should help blend the appropriate quantities of the cement blend and the mix water. The correct ratio will provide the expected slurry density and other properties. Continual verification of slurry density is essential; however, some density fluctuations during slurry mixing are unavoidable. The longer the mixing time and the larger the slurry volume, the better the homogeneity of the resulting slurry.

Finally, the slurry should be given the proper amount of shearing, which is a function of mixing energy and mixing time. Because a centrifugal pump is an ideal shearing device, it is advisable to increase the volume of slurry being recirculated so that such a pump can be used.

Recirculating mixers are available in a variety of configurations (skid-, truck-, or trailer-mounted, diesel- or electric-powered, sometimes soundproofed) and sizes. They all have certain common features (Figs. 11-18 and 11-19).

**Fig. 11-18.** Single 6-bbl tank mixing unit (with conventional jet mixer).

**Fig. 11-19.** Twin-tank mixing unit (with recirculation jet mixer).
- A surge tank with a capacity of 9.4 to 25.2 bbl [1,500 to 4,000 L]
- A conventional or recirculation jet mixer
- One or two holding tanks with a capacity ranging from 6.3 bbl [1 x 1,000 L] to 50 bbl [2 x 8,000 L] (size is limited by transportability concerns)
- Two recirculating centrifugal pumps (only one on the smallest units), with a maximum displacement rate of 25 bbl/min [4,000 L/min], to either circulate the slurry in the holding tank(s) to improve shearing and homogeneity or to feed the slurry to the downhole pump
- A pair of paddle stirrers, hydraulically or electrically driven, to maintain homogeneity
- A manifold, sufficiently versatile to be used in a variety of combinations

In particular cases such as very small jobs, or when the proportions of additives and the slurry density are very critical, the total volume of slurry needed to complete the job (including the usual excess) is prepared before pumping downhole. The liquid additives are not metered as described earlier; instead, they are released directly into the tank or added through a jet mixer. No special practice exists regarding dry additives. The volumes or weights of dry additives are usually measured in the conventional manner.

11-2.8 High-pressure pumps
All current cementing pumps are of the reciprocating type, mostly with three plungers (triplex) and spring-loaded suction and discharge valves (Fig. 11-20). The transformation of the rotating motion of the input shaft into the reciprocating motion of the plungers is generally accomplished either by a system of a crankshaft and connecting rods or by a swash plate and connecting rods system. These pumps include an internal fixed-ratio speed reducer. Depending on the make and the model, the plunger stroke varies from 5 to 10 in. [12.5 to 25 cm].

The global efficiency of triplex pumps is 85% to 90%. If adequately pressurized, the volumetric efficiency can reach 98% with water at 80% of the maximum speed. The construction is particularly rugged, allowing the pumps to handle the heaviest and most abrasive slurries.

11-2.8.1 Convertibility
Depending upon the manufacturer, the “size” of a pump can be altered by changing either the fluid-end assembly or the plungers and packing system, using adapters to convert the fluid-end body. Size alteration changes the pressure and flow ratings without modifying the maximum available horsepower. The plungers used in cementing usually have a diameter between 3 and 6 in. [7.6 and 15.2 cm].

11-2.8.2 Hydraulic horsepower
Depending on the make and the model of the pump, the maximum horsepower varies between 200 and 500 hhp [150 kW to 370 kW].

11-2.8.3 Versatility
Heavy-duty triplex pumps, which can handle gravel-laden fluids, can also perform hydraulic fracturing treatments. In the 200-hhp to 500-hhp [150-kW to 370-kW] range, the same pumps are used for cementing and stimulation.
11-2.8.4 Maximum flow rate and pressure
Available makes, models, and sizes offer a large variety of specifications. One should bear in mind that, during most cement jobs, only one pump is used to pump downhole. Usually the maximum rate is 8 bbl/min [1.3 m³/min]. This limitation is based upon the maximum allowable rate for the 2-in. treating line most commonly used for cementing.

The pump pressure usually does not exceed 1,030 psi [70 bar] (cement squeezes excepted). As a matter of fact, if the density of the cement slurry is equal to that of the drilling mud, the pumping pressure is simply a consequence of the friction losses in the surface equipment (steel flow hoses and cement head) and below the surface.

11-2.8.5 Drive
The pumps on mobile units are driven by a diesel engine and may have either automatic or manual transmissions. Those permanently installed on an offshore rig are frequently driven electrically (usually with a directly coupled DC motor).

11-2.9 Controls and instruments
At or before the start of a job, some control devices on the mixer are selected (e.g., chokes on a jet mixer) or set in position (e.g., a mix-water valve on most recirculating mixers) according to the composition and density of the slurry and the desired injection rate. During the job, the final adjustment is made with either the cement (blend) or the mix-water metering valve, depending upon the type of equipment. Adjustment of the downhole pump rate may also be necessary to maintain a constant level in the slurry tank and maintain the pumping pressure within fixed limits (e.g., squeeze jobs).

Cement jobs require the measurement of many parameters. A discussion of the various types of measuring equipment is given below.

**Mix water**: The volumes of water are measured in the displacement tanks.

**Cement (blend) and slurry**: The volumes of mixed slurry and dry cement are calculated from measurements of the mix-water volume and the slurry density.

**Flow rate**: The slurry flow rate is observed at the downhole pump-stroke counter. A flowmeter is used if job parameters are being recorded continuously.

**Pressure**: The pumping pressure is read at a gauge or mechanical recorder. An electronic pressure transducer is used if the various parameters are recorded by a central unit.

**Slurry density**: The slurry density is traditionally measured manually by a pressurized mud balance (Fig. 11-21). More sophisticated systems determine the slurry density with a mass flowmeter that employs the Coriolis effect (Fig. 11-22) or with a radioactive densitometer connected to a central computer-based recording unit (Fig. 11-23).

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**Fig. 11-21.** Pressurized mud balance (photo courtesy of Chandler Engineering, LLC).

**Fig. 11-22.** Coriolis effect mass flowmeter for slurry-density measurement.
Solids fraction: With the advent of engineered particle size cement systems, it has become possible to design high-performance cement systems at slurry densities approaching that of water (Chapter 7). Under these circumstances, the densities of the mix water, the cement blend, and the final slurry are essentially identical. Therefore, the mixing process cannot be monitored or controlled by conventional slurry-density measurements. To overcome this problem, a different quality-control principle based on solids fraction measurement was developed (Vigneaux et al., 2003).

The solids fraction of a slurry is the percentage of solids contained in slurry sample. It can be expressed in terms of volume or mass. Expressed in terms of volume, the solids fraction is 1 minus the inverse of slurry porosity (Chapter 7).

A schematic diagram of equipment to monitor the solids volume fraction is shown in Fig. 11-24.

Three key parameters are monitored: water flow rate, mixing-tub level, and slurry-flow rate. The water- and slurry-flow rates are measured with electromagnetic flowmeters. The mixing-tub level is monitored by an ultrasonic-guided wave sensor. The solids fraction can be calculated by computing the difference between the slurry-flow rate and the water flow rate. The mixing-tub level is important because the volume of slurry in the tub can fluctuate, and the system must be able to instantly compensate for such fluctuations as it calculates the solids volume fraction.

Slurry rheology: Rheology measurements are not routinely performed at the wellsite. However, a couette viscometer (Appendix B) can be used at the wellsite for ambient-temperature rheology measurements.

Compressive strength: This measurement is rarely made at the wellsite because of the long curing times. Slurry samples are normally taken to a central laboratory for postjob tests.

Computer-based central recording units are available to continuously record vital pumping parameters (Fig. 11-25). The recorders significantly improve onsite job monitoring while simultaneously storing data for postjob evaluation. The stored data can be used to produce job-data sheets and enhanced graphics for in-depth analysis. Slurry density, flow rate, and pressure can be monitored for various configurations of pumping equipment. The microprocessor calculates and displays cumulative volumes, and the total volume is printed on the log in increments as short as one second.

One can imagine that the continuous monitoring of key pumping parameters could be used to automatically control slurry mixing. As of this writing, equipment applying such a principle is beginning to appear in the...
field. In the near future, automatic cement mixing will undoubtedly become a routine procedure.

11-2.10 Steel flowhoses and cement head
A “cement head” (Section 11-5.14) is screwed into the top casing collar or landing joint, depending on the type of cement job. The discharge side of the downhole pump and the cement head are connected by a series of articulated or straight sections of high-pressure steel pipe, also known as “treating iron” (Fig. 11-26).
11-3 Cementing units

The various components of cementing units, which fabricate and inject the cement slurry, have been described individually in Section 11-2. Figure 11-27 illustrates the combination of the components to assemble a basic cementing unit. A variety of configurations and compositions exists, tailored to the type of rig to be serviced and the redundancy, versatility, and mobility required.

The various configurations are described below, according to the type of rig to be serviced.

**Skid-mounted units**: Illustrated in Fig. 11-28, skid-mounted units are most applicable to isolated land rigs, offshore rigs, cementing barges (lakes and rivers), and open-sea cementing vessels.

**Truck-mounted units**: Shown in Fig. 11-29, such units are suitable for almost any land rig. However, the chassis must be adapted to the type of surface upon which the unit will travel. The “standard” unit is designed to travel on roads and must conform to local road regulations. The “off-road” unit is built for more difficult terrain. The “desert” unit can be driven over soft surfaces, even sand dunes.

![Typical cementing skid and control console.](Fig. 11-28)

![Basic cementing unit diagram](Fig. 11-27)

**Fig. 11-27.** Mixing and pumping equipment on rig site (typical setup).

- 1. Centrifugal water supply pump
- 2. Water distributor
- 3. Additive distributor
- 4. Displacement tank system
- 5. Mixing water pump (centrifugal—low-pressure mixing; reciprocating—high-pressure mixing)
- 6. Mixing water manifold
- 7. Cement mixer (conventional jet mixer shown)
- 8. Slurry tub
- 9. Centrifugal pressurizing pump
- 10. Reciprocating displacement (downhole) pump(s)
Semitrailer-mounted units: Like the truck-mounted units, semitrailer-mounted units as shown in Fig. 11-30 are appropriate for almost any land rig. They can be drawn by many types of tractors, providing a logistical advantage. A heavy tractor-drawn unit with five axles has a better weight distribution ability than the corresponding truck with only three. The maximum authorized payload is greater than that of the truck, which allows the loading of more equipment on the same chassis.

Helicopter units: Helicopter units are intended for rigs totally inaccessible by land or water. The units, the mixing equipment, and the cement silos are designed to be transported by helicopter. They can be dismantled into smaller components, incorporating lifting frames, and are often made of lighter materials to reduce weight.

Traditionally, a cementing unit contains two of each vital item. This redundancy is necessary because a well can be severely damaged or lost if it becomes impossible to complete a job after it has commenced. The extra equipment serves as an “insurance policy” to protect the operator's investment.

However, single-pump units now exist. One such unit is shown in Fig 11-31. This unit provides a cost-efficient solution for less-critical, lower-pressure well casing jobs. High-pressure treating iron is replaced with a flexible hose for faster wells site rig-up.

For economic reasons, a cementing unit is designed to meet the requirements (including road regulations) of as many locations as possible. In Europe, for example, the required specifications vary from one country to another, and the unit must conform to the most stringent regulations. In addition, soundproofing is more frequently demanded because of the proximity of wells to residential areas (Fig. 11-32).

Cementing-unit designs are developed with special attention to safety and environmental requirements. Environmental release of wastes (liquid or dry chemicals, cement slurries, or pump or engine oil spillages) is prevented by better equipment design and the use of recovery receptacles.
The safety requirements with which the equipment should comply depend upon the location and are especially dependent upon possible sources of flammable or explosive gases. Whenever the unit can be placed more than 98 ft [30 m] away from the well (as on most land rig sites) there are no special requirements. Standard equipment can often be used without modification. This distance condition is often difficult to satisfy on offshore rigs, where every compartment or deck location is classified according to the potential risk of explosion or fire. The classification is made by official regulatory bodies according to standards that may vary slightly from one country to another; however, operators usually adhere to the most stringent regulations.

For example, the following is a summary of the Det Norske Veritas (DNV) requirements for diesel engines to be located in a hazardous area, classified as “Zone 2,” in which an explosive gas mixture may exist for a short time only under abnormal conditions. Diesel engines are banished from Zones 0 and 1, which are more sensitive areas. The DNV is the Norwegian certification body, and its standards serve as a reference in the North Sea.

1. Special water-cooled manifold rated to cool exhaust gas to 200°C (392°F) maximum, and with a surface temperature not exceeding 200°C at any point.
2. Oversized radiator.
3. Inlet air combustion, slam-shut valve.
4. Inlet air flame trap.
5. Exhaust gas spark arrester, DNV type approved.
6. Overspeed valve, which closes the engine blower flapper valve when speed exceeds the normal maximum by 10%.
7. High-water-coolant temperature valve, which shuts down the engine when water temperature exceeds 95°C (204°F). Fuel rack actuated.
8. Low-water-coolant level valve, which shuts down the engine.
9. High-exhaust-gas temperature valve, which shuts down the engine when the gas temperature exceeds 200°C.
10. Special control panel.
Diesel engines must often be adapted further to meet fire-protection standards. The equipment required to adapt an engine is sophisticated, entirely made of high-quality stainless steel, and bulky. It is extremely expensive. Electric motors for Zone 2 areas are typically confined in a closed shelter, which is pressurized with air taken from a safe area. An overpressure is maintained so that no gas from the hazardous area can enter the shelter. When a cementing unit is to be operated offshore in a nonhazardous area, the drilling and service companies often opt for “protected” diesel engines, which provide increased security at a more reasonable cost. Following is a list of the devices that should be installed on a standard diesel engine to ensure this protection.

1. Overspeed valve, which closes the engine blower flapper valve when speed exceeds the normal maximum by 10%.
2. High-water-coolant temperature valve, which shuts down the engine when water temperature exceeds 95°C. Fuel rack actuated.
3. Low-oil-pressure valve, which shuts down the engine when engine oil pressure is below a value to be settled with the manufacturer. Fuel rack actuated.
4. High-oil-temperature valve, which shuts down the engine when oil temperature exceeds 130°C (266°F). Fuel rack actuated.
5. Special control panel.

11-4 Introduction to casing hardware

This section focuses on equipment used on or within the casing string to enhance casing placement and cementing operations. Within the petroleum industry, this equipment is commonly referred to as casing and liner hardware and cementing tools. These tools fall into five basic categories:

- **Float equipment**
- **Centralization and flow enhancement tools**
- **Elastomers—casing or liner wiper tools and inflatables**
- **Stage tools**
- **Torque and drag reduction tools**

An entire textbook could be written about these tools; for this textbook, the discussion will be limited to the most common or basic types, with the emphasis placed on application, principles of operation, and basic design characteristics.

Years ago, most casing hardware was manufactured and sold by the cementing company, and the operator depended upon the service companies to develop new tools. Today, a multitude of engineering groups and manufacturers supports and supplies the cementing companies with most casing hardware.

Some cementing tools are retrievable devices that may require some form of operation from the surface. These tools are usually operated by specialists or tool operators within the cementing companies and are typically associated with remedial cementing operations such as squeeze jobs or pressure testing. Packers, bridge plugs, and retainers are examples of cementing tools that are commonly used for squeeze or plugback cementing.

11-5 Casing hardware

A typical application of casing hardware for a primary cement job of moderate depth is shown in Fig. 11-33. The lower end of the casing is protected by a guide shoe or float shoe. A float collar or autofill collar is placed one or two joints above the shoe to provide a seat to land cement plugs and to halt cement displacement. The short section of casing between the shoe and float collar is called the shoe joint and is provided as a buffer within the casing to contain fluid contamination that may build up ahead of the top wiper plug. The length of the shoe joint may be as few as 1 joint (40 ft [12 m]) or as many as 10 joints, but most operators use 2 joints. The length of the shoe track is sometimes adjusted on the rig to accommodate a lack of confidence in the accuracy of the rig pump efficiency. Rig pumps are often used to displace the cement and plug(s). Plugs act as physical barriers to separate the cement slurry from the drilling mud and displacement fluids.

Centralizers are placed in critical sections to prevent sticking while the casing is lowered into the well. Then they keep the casing in the center of the borehole to aid mud removal and help ensure placement of a uniform cement sheath around the casing in both the openhole and cased hole sections.

11-5.1 Guide shoes and float shoes

Guide shoes and float shoes are tapered, commonly bullet-nosed devices that are installed at the bottom of the casing string. They guide the casing toward the center of the hole to minimize hitting rock ledges or washouts as the casing is run into the well. The outer portions of these shoes are usually made from steel, generally matching the casing in size and threads. The
inside (including the taper) is generally made of concrete or thermoplastic, because this material must be drilled out if the well is to be deepened beyond the casing point. Guide shoes and float shoes are made in a wide size range, from 3½ to 24 in. [8.9 to 61 cm] in diameter, and they are generally used in surface-to-intermediate casing strings at shallow depths.

The guide shoe differs from the float shoe in that it lacks a check valve. The check valve in a float shoe can prevent reverse flow, or U-tubing, of cement slurry from the annulus into the casing. The float shoe also reduces hook weight, because the check valve increases the buoyancy of the casing string by preventing backflow of fluid as the casing is lowered into the well.

A basic guide shoe is shown in Fig. 11-34. The steel shell is molded into a rounded nose with a central orifice.

Fig. 11-33. Typical application of casing hardware for a primary cement job (drawing courtesy of Weatherford International).

Fig. 11-34. Basic guide shoe (drawing courtesy of Weatherford International).
A variation is the “down jet” guide shoe. This modification incorporates some side jets or ports to divert all or part of the fluid (Fig. 11-35). The purpose of the jets or ports is to promote high displacement efficiency by distributing the fluids evenly around the annulus. The jets come in a wide variety of sizes and shapes. The concrete nose is fairly strong, yet can be easily drilled with polycrystalline diamond compact (PDC), insert, and roller cone bits.

**11-5.1.1 Nose materials and shapes**

Guide shoes and float shoes are available with various nose designs, each built for a specific purpose. Most common among these is the cement nose guide shoe. The slightly rounded nose is usually made with high-strength concrete that has a compressive strength of 8,000 and 10,000 psi [5.5 and 6.9 MPa]. The rounded nose allows the casing to be deflected off of ledges and obstructions as the casing is lowered. The shells of guide shoes and most float equipment have grooves into which the cement flows when poured. As a result, the cement is not held in place by shear bond alone, and it has the strength to withstand the stresses associated with casing placement and the subsequent cement job.

Aluminum nose shoes are another option; however, their popularity has been diminished by the introduction of concrete and composite materials. Aluminum noses can be cast into a wide variety of shapes. Lengthened noses can ease movement past bridges and obstructions downhole (Fig. 11-36).

Composite nose guide shoes are the newest option, made possible by the advent of composite materials that can withstand high load weights and resist abrasion, erosion, and high temperatures (Fig. 11-37). For example, a typical 9½-in. eccentric nose float shoe can withstand end loadings greater than 100,000 lbm [45 SI ton] at temperatures exceeding 250°F [121°C]. Their performance exceeds the American Petroleum Institute (API) specifications, and they can withstand running into wellbores up to and beyond 90° inclination.
Other types of guide shoes include the Texas pattern (beveled nose) and the sawtooth pattern (Fig. 11-38). The noses of these guide shoes are formed or cut out of the steel shell. The beveled nose shoe has the same outside diameter (OD) as the couplings and an inside diameter (ID) that is the same as the casing or drillout diameter. The bevel is advantageous in situations in which it is necessary to pull back the bottomhole assembly through the previous casing. The beveled guide reduces the probability of sticking.

The beveled nose shoe is most often run in shallow, vertical wells. Such bevels are also incorporated into most float shoes.

In recent years, the price of float shoes has decreased, and many operators use them routinely to have the option of an additional valve in the casing string. However, in deepwater applications, guide shoes are making a comeback. The guide shoes leave an unrestricted path for tripping devices to pass through.

11-5.2 Float equipment

The primary purpose of float equipment is to be able to pump cement slurries into the well that are heavier than the mud. Check valves prevent the cement from U-tubing back into the casing or liner string (Fig. 11-39).

Float equipment consists of specialized casing shoes and collars with check valves to prevent wellbore fluids from entering. As the casing is lowered, the hook load or hanging weight is reduced by the weight of fluid displaced. The casing is filled from the surface, and the hook load or amount of buoyancy is controlled by monitoring the weight indicator. The frequency of filling is generally once every 5 to 10 joints; however, some large-diameter or thin-wall casings may require more frequent filling to prevent casing collapse. In addition to proper filling, the casing should be lowered at a slow, steady rate to prevent pressure-surge damage.
As the demand for larger and heavier casings has increased, so has the concern for derrick stress and fatigue. Float equipment can be used to reduce derrick stress by inducing flotation or increased casing buoyancy by simply not filling the casing or liner while running into the wellbore. After landing, the casing is filled and circulation is slowly established to begin hole conditioning. Flotation devices must be carefully deactivated, slowly releasing trapped air inside the casing; otherwise, casing collapse may occur. A specialist from the vendor supplying the flotation device is usually present to monitor its use. A typical casing flotation system is shown in Fig. 11-40. The operating sequence is shown in Fig. 11-41.

Owing to the risk of casing collapse during the flotation of larger strings, some operators and consulting groups are studying casing drag more closely. In shallower, high-angle wellbores, casing drag and differential sticking frequently impede pipe placement to total depth (TD). Roller centralizers are being proposed as a safer method to reduce friction (Section 11-5.11).

Circulating at least one hole volume of mud is typically required before performing the primary cement job; however, to optimize hole and mud conditions for cementing, some drilling programs call for many hours of circulating (Chapter 5). Most float equipment valves have been rated (after testing according to Recommended Practice for Performance Testing of Cementing Float Equipment [API RP 10F]) to withstand more than 24 hr of solids-laden fluid flow at 10 bbl/min and to hold 5,000 psi of backpressure after circulation is complete.

After the cement is displaced, the float valve must prevent backflow into the casing. Should the float valve fail, surface pressure must be applied until the cement hardens to prevent U-tubing. Applying surface pressure is undesirable because it expands the casing while the cement hardens. When the pressure is released, the casing relaxes, potentially creating a microannulus between the casing and cement.

![Typical casing flotation system](drawing courtesy of Davis-Lynch, Inc.)
1. Bottom portion of casing is run dry (not filled with fluid), with flotation collar installed at desired depth. Casing above the collar is filled with drilling fluid as casing run continues to desired depth.

2. Casing pressure is increased until the opening sleeve shifts down to permit fluid and air to swap. After a fluid stabilization period, the casing is filled with drilling fluid.

3. Bottom cementing plug is launched ahead of cement. After landing on the bottom sleeve, it pushes both sleeves ahead of the cement to the float collar below.

4. Bottom cementing plug and sleeves land and seal on the float collar. Bottom cementing plug ruptures, and cement is pumped through and out of the float equipment.

5. Top cementing plug seals and locks on bottom cementing plug/collar assembly at the float collar.

**Fig. 11-41.** Operating sequence of casing flotation system (drawing courtesy of Davis-Lynch, Inc.).
11-5.3 Valve materials and types

The three most common types of check valves used in casing hardware are the ball, flapper, and poppet valves. They have been adapted for floating and autofill applications and are commercially available from several suppliers. There are many specialized variations, the latest of which is the large-bore double-flapper valve, used for surge reduction in deepwater applications. The large bores offer less resistance during the autofill process.

API RP 10F provides standard methods for equipment testing and a classification system based on performance capabilities. On scales of I, II, and III and A, B, and C, the best equipment rating is III-C.

Materials used in valves vary depending on requirements for drillability, compatibility with bits, and temperature stability. The major valve components are generally made of phenolic resin, composites, or aluminum. Nitrile rubber is used for valve seals and coatings rated for service at temperatures up to 300°F [149°C]. Beyond that temperature, viton rubber is used. Most large springs are made from a phosphorus bronze, beryllium, or aluminum alloy. Steel parts such as springs and pins are generally too small to pose a problem; nevertheless, they are always tested to verify that they are drillable with PDC bits. Plastic parts are typically made from thermoset materials such as phenolic resins that are stable to temperatures as high as 450°F [232°C] and inert to most oils and synthetic mud components. They are easily drilled and are compatible with most bits. Aluminum is easily drilled, but it has a tendency to foul or smear over some diamond or fine-cutter bits when found in large masses unless the PDC bit is modified to drill soft metals.

**Ball valves** consist of the typical ball-and-cage arrangement (Fig. 11-42). The ball is generally made from weighted phenolic resin and may be rubber-coated. The cage may be made of plastic or aluminum. The ball is buoyant in many drilling fluids and cement slurries; however, when the hole is deviated, reverse flow may be required to return the ball to its seat. Ball check valves may not be effective in preventing a slight reverse flow or gas migration in highly deviated holes.

The minimum clearance between the ball and the cage may be one-half inch or smaller. Solids such as mud scale or cuttings should be avoided to prevent wedging of the ball or plugging the valve. Likewise, ball valves are not recommended for use in muds containing heavy concentrations of lost circulation materials (LCM). The backpressure resistance of the ball valves is more than adequate for most applications. The temperature stability and wear resistance depend greatly upon the materials used and the construction of the valve. The use of ball valves as the primary valve for cement placement is waning. Poppet valves (described later) are more popular today because of their superior erosion resistance.

**Flapper valves** are composed of a spring-loaded flapper hinged to a plate with an integral seat (Fig. 11-43). The flapper and plate are generally made of aluminum or composite materials. The spring-loaded seating action is virtually unaffected by hole deviation. The flapper opens proportionally to the rate at which fluid is being pumped and the strength of the spring in the flapper. Because of the irregular surfaces behind the flapper and spring, smaller valves tend to induce a large amount of turbulence during flow. This increased turbulence can easily cause erosion and seal damage when the flapper is not completely open, leading to a short valve life.

A variety of flapper valves is available to fit within most API threads such as 8-round or buttress as well as cemented versions of conventional shoes and collars. The new generation of composite large-bore flappers (diameters greater than 3 in. [7.6 cm]) opens to provide a large, unobstructed flow path that passes tripping balls and extraneous materials without blockage or harm to the valve. The temperature rating of composite flapper valves is less than 300°F [149°C]. Aluminum valves are available for service at higher temperatures.
Bump pressure ratings are based on the way the valve is cemented in place or the number of threads in the valve body. Backpressure resistance is highly dependent on the valve body and is generally more than adequate for most conditions. The wear resistance varies with size and manufacturer; it should be specified for circulating applications longer than 8 hr.

Poppet valves are composed of a spring-loaded poppet (also referred to as a plunger or cone) housed in a cage much like that of a ball valve (Fig. 11-44). Phenolic resin or aluminum is used for the cage, and the poppet is often made from nitrile rubber or is rubber-coated. Like the ball valve, the poppet valve has a restricted flow path. Solid debris that may plug or bind the poppet should be avoided. The spring-loaded seating action is virtually unaffected by hole deviation. The temperature resistance depends on the type of materials used and should be specified by the supplier. The pressure resistance typically exceeds that of the flapper and ball valves. Wear resistance is also generally good but should be verified before using poppet valves in extended-circulating-time applications.

The poppet spring is usually a nonferrous material such as phosphorus bronze or beryllium copper. Generally, softer alloys are used for the spring materials and are chosen according to the temperatures they will experience. It is widely assumed that the springs in poppet valves are very strong, but this is far from true. The purpose of the spring is to simply lift the poppet into its seat. The differential pressure of the fluid trying to reenter the pipe holds the poppet in place.

There are two types of poppets on the market today. The more common type, shown in Fig. 11-44, has the head on the top of the stem. Another version has the head or sealing area on the bottom of the stem. This generally results in a shorter piece of equipment for the float collar, but may pose a problem on the float shoe (for clearance).

Table 11-3 is a summary of the advantages and disadvantages associated with the various types of valves.
11-5.4 Surge pressure and float equipment

Pressure surges are generated each time the casing is raised and lowered; they are the product of inertia and flow resistance of the displaced fluid. Pressure surges combined with hydrostatic-pressure differentials may exceed the casing-collapse or the formation-fracture pressures, causing loss of mud or permanent formation damage. As the trend continues towards reducing the number of casing strings in a well, many operators are running reduced-clearance combinations such as

- 177⁄8-in. to 18-in. casing through 20-in. hole
- 16-in. to 177⁄8-in. casing through 18-in. hole
- 133⁄8-in. to 135⁄8-in. casing through 16-in. hole
- 113⁄4-in. to 117⁄8-in. through 133⁄8-in. to 135⁄8-in. hole
- 95⁄8-in. to 97⁄8-in. casing through 113⁄4-in. to 117⁄8-in. hole
- 7-in. to 75⁄8-in. casing through 95⁄8-in. to 97⁄8-in. hole.

External attachments such as centralizers and reciprocating scratchers may increase the flow resistance and should be considered when determining a safe lowering speed. Fig. 11-45 shows four ways to run casing or liners into a well. Pipe ending conditions include

- closed pipe
- fully open pipe
- pipe with autofill restriction
- pipe with circulating sub (flow diverter).

In all of these scenarios, the surge-pressure calculations are based on many assumptions. Many drilling fluids are compressible; therefore, surge pressures should be reduced compared to conventional steady-flow models. Unsteady flow conditions are reduced to a stationary flow regime model by considering an improved mud clinging constant (Fig. 11-46). Clinging constants were addressed in earlier works by Burkhardt (1961) and Fontenot and Clark (1974) and are incorporated into much of the mud displacement software used today.

### Table 11-3. Advantages and Disadvantages of Various Types of Valves

<table>
<thead>
<tr>
<th>Types of Valves</th>
<th>Flapper</th>
<th>Ball</th>
<th>Phenolic Poppet or Cone</th>
</tr>
</thead>
<tbody>
<tr>
<td>Advantages</td>
<td>Inexpensive</td>
<td>Simple</td>
<td>Self-closing</td>
</tr>
<tr>
<td></td>
<td>Least restrictive</td>
<td>Easy to use</td>
<td>Erosion-resistant</td>
</tr>
<tr>
<td></td>
<td>Self-closing</td>
<td>Easy to drill out</td>
<td>0-90° inclination</td>
</tr>
<tr>
<td>Disadvantages</td>
<td>High erosion susceptibility</td>
<td>Dependent on flow to close</td>
<td>Low tolerance to some LCM (e.g., fibers)</td>
</tr>
<tr>
<td></td>
<td>Easily blocked</td>
<td>Poor performance in inclined wellbores</td>
<td>Easily damaged</td>
</tr>
<tr>
<td></td>
<td>Difficult to drill out</td>
<td>High erosion susceptibility</td>
<td></td>
</tr>
</tbody>
</table>

![Fig. 11-45. Different types of surge models (drawing courtesy of Pegasus Vertex).](image1)

![Fig. 11-46. Graphic modeling of clinging characteristics of fluids on moving pipe (drawing courtesy of Pegasus Software).](image2)
Calculation of the pipe speed during the running process or reciprocation is based on creating an acceptable annular flow velocity, often equivalent to that used during drilling. Unfortunately such a velocity is not always possible, because the fluid viscosity varies with temperature and time. In openhole sections, the formation may react with the drilling fluid, resulting in swelling (reducing the annular volume) or caving as loose material falls into the annulus.

In the absence of surge pressure calculation software, Eq. 11-1 may be used. The equation is derived from the Bingham plastic model and can be used to estimate a safe maximum lowering speed at a particular depth. The effects of hole abnormalities and external attachments are neglected. Turbulent flow is assumed, and a worst-case friction factor of 0.016 should be used.

\[
v_{pipe} = \left[ \frac{25.6 D p_a (d_{hole} - d_{pipe})}{f_{frict}} \right]^{0.5} \times \left[ \frac{(d_{hole})^2}{(d_{pipe})^2} - 1 \right],
\]

(11-1)

where

- \(d_{hole}\) = hole diameter (in.)
- \(d_{pipe}\) = pipe diameter (in.)
- \(D\) = depth (ft)
- \(f_{frict}\) = mud friction factor (use of a worst-case 0.016 is suggested)
- \(g_{frac}\) = fracture gradient
- \(p_s\) = the lesser of \(p_{sf}\) or \(p_{sc}\), where
  - \(p_{sf} = 0.5 L (g_{frac} - 0.052p)\), for formation protection
  - \(p_{sc} = 0.5 (p_{min} - 0.052p)\), for casing protection
- \(p_{min}\) = minimum casing collapse resistance (psi)
- \(v_{pipe}\) = maximum casing velocity to prevent damage to casing or formation
- \(\rho\) = fluid density (lbm/gal).

Some apply general safety guidelines such as limiting the pipe speed to 2 ft/sec [0.6 m/s]. Such rules are not practical. For example, running 13¾-in. casing inside a 16-in. casing and a 17½ in. open hole certainly would not be the same as running a 5-in. liner inside a 6-in. open hole. Another concern with pipe velocity analysis is making sure the drill crew is measuring the maximum velocity. As a rule, most programs assume the maximum velocity is 1.5 times the average velocity. Controlling the lowering speed of 90-ft stands of drillpipe is extremely difficult without compensating for acceleration and deceleration. As a safety precaution, if 1.5 ft/sec is desired, one should request 1.0 ft/sec.

The primary method of lowering the surge pressure while running casing or liner pipe is to allow fluids to enter the casing from the bottom. This lowers the volume of fluid passing up through the annulus. This led early float equipment developers to expand on the use of automatic fill float equipment many years ago. Today, it is a major component of most deepwater casing strings.

### 11-5.5 Automatic fill-up equipment

Automatic fill-up shoes and collars contain check valves similar to those used in float equipment (Fig. 11-47). However, the check valves are modified to remain in the open position to allow filling or even reverse circulating. The casing fills continuously as it is run downhole, saving rig time and reducing the pressure surges associated with float equipment. The valves are usually designed to reduce casing overflow but, as the clearance between...
casings becomes smaller, this becomes challenging. Stopping overflow while reducing surge pressure requires one to reduce the pipe running speed. Running the casing quickly while reducing the surge pressure requires one to eliminate restrictions on the float equipment and contend with mud returns on the rig floor or downhole. This can be accomplished with a diverter tool that is placed directly above the restrictive section, usually the first joint of drillpipe above a liner or casing hanger.

Autofill equipment must be activated, or converted, to begin functioning as a one-direction check or float valve. Conversion is generally performed after the casing is in place; however, it can also occur while running casing to prevent overflow, control the hook load, or to control the well. Sudden stops while lowering the casing should be avoided to prevent premature valve conversion. The maximum flow rate of fluids down the casing may also be limited to prevent the valve from being unintentionally activated.

Small-orifice and poppet valves are not recommended for use with drilling fluids containing high concentrations of LCM, or large-particle-size LCM. Using a large number of reciprocating scratchers and other external attachments may increase the annular flow resistance and cause overflowing.

**Casing insert equipment**

Insert equipment offers an economical means of providing floating and autofill valves for shallow-to-moderate depth and pressure applications. Insert equipment is generally available for 10%-in. and smaller casings, supplied with API 8-round long or short couplings. They are made of aluminum and composite materials and contain ball, flapper, or latch-in valve mechanisms.

Insert valves are installed within a coupling and are trapped between the above and below joints of casing. Their strength is limited to the material trapped with the coupling, which is usually aluminum. The insert valve must be fully made up to prevent damage and interference with proper casing engagement. When landing a plug, the rate should be reduced to prevent pressure spikes that may exceed the strength of the insert.

*Autofill or orifice fill* (flapper) valves are converted by ejecting the orifice tube, allowing the spring-loaded flapper to close (Fig. 11-48).

The conversion operation usually requires the use of a weighted phenolic ball or, in some cases, a small zinc or brass tripping ball. To save time in vertical wells, the ball is generally dropped into the casing and allowed to free fall while running the last 5 to 10 joints. The free-fall rate is estimated at 200 ft/min [61 m/min]. The ball may be pumped down; however, should it set while pumping, the conversion may occur without an indication that is easily recognized. With the ball properly seated, the orifice tube may be discharged by applying 300 to 800 psi pressure, depending on the manufacturer.

**Large-bore autofill float equipment**

A new family of large-bore autofill float equipment was developed to meet the need for increased surge reduction. Most of the newer types of large-bore autofill equipment use a double-valve design flapper held open by a single 24- to 36-in. [0.6- to 0.9-m] long aluminum or composite tube. Composite tubes are preferred because they are easier to drill out with PDC bits. The openings are typically 3.5 in. [8.9 cm] across the ID of the tube and have a 3.25-in. seat for the ball (Fig. 11-49). As a result, the path of least resistance for any fluid is up the casing string, offering the maximum surge reduction.

There are two operating modes in autofill flapper valve equipment—filling and nonfilling. In the filling mode, it is possible to circulate the fluid through the casing before landing without losing the autofill capability. This capability is required to circulate past an obstruction or a sand bridge. The nonfilling mode can be used when one is absolutely sure that autofilling is not required or that filling can be performed from the surface.

This next option is dictated by the operator’s desire for fast response to well control issues or hole deviation. If the conversion method requires dropping a ball, it can be dropped from the surface for near-vertical wells, usually up to 30° deviation. If the ball is not pumped, one should allow 3–5 min per 1,000 ft for the ball to reach its target.
The other option is to have the ball trapped inside the autofill valve in a cage mechanism above the valve, where it will remain until downward circulation begins. Circulation flow will force the ball into the seat, build up backpressure, and deactivate the autofill mechanism. The limiting factor is that the ball can restrict the flow of autofilling fluids and the solids carried therein.

If the 3½-in. ball cannot pass through the drillpipe, liner equipment, or subsea plugs caused by ID restrictions, then the ball can be inserted inside the casing before the hanger or running tools are threaded together. This is commonly called “floating the ball.” Another option is to locate the ball inside a launching device (Fig. 11-50) below the restrictions (e.g., a subsea or liner plug).

**Fig. 11-49.** Operational sequence of a typical large-bore autofill collar (drawings courtesy of Weatherford International).
A: Run-in position
B: Circulation position after ball is dropped into place
C: Circulation pressure increased until the pressure drop across the small ports at the bottom of the inner sleeve exceeds the shear pin ratings holding the sleeve in place
D: Converted position, now standard double-flapper float collar

**Fig. 11-50.** Mechanism that allows a ball to be launched from the end of a subsea or liner plug set (photograph courtesy of Weatherford International).
Other autofill float equipment valves

The poppet autofill valve (Fig. 11-51) contains a spring-loaded plunger that is held open to allow filling. There are several methods available for holding the plunger open, and most valves require a preset downward flow rate for release. They include the older ball and wedge design mechanisms. The minimum flow rate is generally between 4 and 8 bbl/min [0.6 and 1.3 m³/min]. However, some devices are designed to release at a predetermined hydrostatic pressure. Poppet collars are usually designed to retain the tripping mechanism, so two poppet units (shoe and collar) may be used to provide added seal insurance. While the autofill valve can be run with a guide shoe, it is important to not combine autofill float valves with standard poppet valves.

New autofill poppet valve designs use a spinning impeller mechanism to release the poppet stem. After a certain amount of pumped fluid at a given rate is circulated past the impeller, the impeller threads itself off a brass stem to convert the valve to a standard poppet valve.

There are also hydrostatically sensitive mechanisms that allow the poppet valve stem to be released after reaching a predetermined hydrostatic pressure. These devices are accurate to ±100 psi. A thorough knowledge of the true vertical depth is required at all stages when using this valve.

11-5.6 Differential fill equipment

Differential fill shoes and collars combine the benefits of floating and autofill equipment (Fig. 11-52). They are designed to automatically fill and regulate the fluid level within the casing. Most differential fill units (shoe or collar) will keep the casing approximately 90% full with respect to the annular fluid level. Therefore, in theory, the casing should remain about 81% full when both a shoe and collar are used. As with all equipment, pipe speed, fluid viscosity, gel strengths, and other factors tend to reduce this accuracy, and the utmost care should be taken to verify the fluid height inside the casing to prevent pipe collapse.

Differential fill and autofill equipment is often used on long strings to reduce surge pressures and the possibility of formation damage, which is normally associated with float equipment (Fig. 11-53). This equipment also saves time, which reduces the probability of sticking. The fluid-level regulating feature reduces the hook load and, at one time, was thought to prevent overflow provided the annulus is not restricted. Experience has shown that this is not always true. Circulation may be established without harming the valve as long as the valve does not have a trapped conversion ball. The valve will resume operation when the fluids in the casing and annulus reach the designed level.

Fig. 11-51. Poppet autofill valves (drawings courtesy of Weatherford International).

Fig. 11-52. Differential fill float collar (drawing courtesy of Davis-Lynch, Inc.).
The typical differential valve regulates fill-up through the action of a floating differential piston. The piston slides up to open and down to close and is designed so that the upper pressurized surface area is approximately 10% larger than the lower. The forces acting to shift the piston are produced by hydrostatic pressures acting on the upper and lower surfaces. Because the upper area is larger, less pressure above is required to balance the forces across the piston. When the pressure above (casing hydrostatic) exceeds 90% of the pressure below (annular hydrostatic), the piston will slide down to halt the filling. Likewise, when the pressure below exceeds 90% of the pressure above, filling will resume by moving the sleeve upwards. This cycle is continuously repeated as the casing is lowered. However, cycling may not begin until the hydrostatic pressure is sufficient to overcome frictional forces associated with the O-rings.

The inoperative flapper valves may be converted to function as float valves at any time. Converting most valves requires a tripping ball (usually in the 1.5 to 2.0 in. size) operation like that described for orifice fill equipment. Circulating before dropping the ball may help clear the ball seat of debris. To verify proper tripping pressure, the ball should be allowed to fall to the seat before pumping. The pressure required to trip most valves is generally between 500 and 800 psi [3.4 and 5.5 MPa]. Because only the ball is discharged, a shoe and collar may be used, and both may be tripped with a single ball. A differential fill or guide shoe may also be used below a differential collar, provided the tripping ball is compatible with both units. One should always verify that the drop ball to convert the collar is compatible with the guide shoe.

The following are some additional precautions.

- To reduce float valve wear during long circulating and conditioning periods, the tripping operation may be delayed until just before pumping cement.
- Because of restrictions in the fill-up path, the casing should be lowered at a moderate rate (generally 1 ft/sec) to reduce pressure surging. The availability of surge prediction software has made this a much safer operation today, and this software should be used before running casing. For optimal protection, it is best to enter the mud properties measured during the wiper trip.
- LCM may tend to slow or prevent filling, which may increase surging or lead to collapse. Periodic circulation and monitoring the weight indicator may be necessary.
- Hole deviation and casing size may prohibit the use of a weighted tripping ball. Some manufacturers offer ball guides for deviations that exceed 20 to 30°. Others trap or preload the ball, which should allow use at any deviation; however, circulation is also prevented before tripping. The supplier should provide information about the maximum allowable deviation.

### 11-5.7 Inner string cementing equipment

Inner-string cementing is a technique typically used with large-diameter casings in which drillpipe is placed inside the casing as the conduit for pumping fluids from the surface to the casing annulus (Fig. 11-54). The inner strings can be run in one of three ways.

#### Stab-in

With the stab-in method, a simple stinger is fitted to the bottom of the drillpipe and then lowered into the receptacle (usually plastic) where a set of O-rings or special seals are engaged (Fig. 11-55). Once the casing reaches the desired depth, the stab-in stinger and centralizer are connected to the drillpipe and run into the casing. The drillpipe is lowered until the stinger engages the receptacle. For stingers without a latch, additional weight must be applied to counteract the lifting force (backpressure) created while cementing. The maximum lifting force may be estimated by multiplying the maximum expected pumping pressure by the end area of the stinger, including the seals. A simple guideline is to apply 10,000 to 20,000 lbf [44.5 to 89.0 kN] to provide adequate pipe weight. One should also check for
fluid coming up the annulus. If it is not sealed, then add an additional 10,000 to 20,000 lbf [44.5 to 89.0 kN]. Achieving this weight may require the use of drill collars or heavy-weight drillpipe, so this weight availability should be considered ahead of time.

The shoes and collars are basically larger versions of the types previously discussed, with the addition of a seal receptacle and beveled surface. They are available for 9\%-in. and larger casings, but are most often used in 18-in. and larger sizes. In some floating-rig offshore locations, the drillpipe stinger is actually suspended above a standard float collar or shoe, and the cement is pumped into the float equipment to compensate for wave motion, because it represents the path of least resistance.

Stab-in receptacles on the float collar are often fitted with a latch-in plug receptacle, which differs from a latch-in stinger. Using drillpipe gives the operator a positive indication that the displacement process is complete because there is direct observation from the surface. It also leaves behind one more seal to prevent any U-tubing of the cement back inside the casing.

**Screw-in**

The screw-in stinger (Fig. 11-56) is also mounted on the end of the drillpipe, but the stinger has a set of coarse threads located above the seal assembly. The threads are mated to an aluminum or cast-iron receptacle on top of the float collar and can be released with about 11 turns to the left. This feature is sometimes used to run the casing like a scab liner (Chapter 14), but this operation is dangerous because the casing is in compression when picked up from the bottom by the drillpipe, thus reducing the collapse pressure. Most float equipment of this type is rated to about 100,000 lbf [445 kN] of pickup force, but the rating must be verified by the vendor. This version of float equipment is seldom made to be PDC-drillable.
Latch-in

The latch-in system is similar to the screw-in stinger, but the stinger is fitted with a split threaded ring that allows the stinger to be stabbed in (Fig. 11-57). The stinger must be rotated out or unscrewed to be released. Today, very few operators use the latch-in stinger because of potential release problems in the field.

Casing running operations are designed according to the type of valve used. The lowering speed should be slow enough to prevent surging. Float equipment may require more frequent filling to prevent collapse.

The inner string isolates the casing interior from the pumping and hydrostatic pressures created while cementing. Care should be taken to prevent creating pressure differentials that may exceed the collapse resistance of the casing. To help prevent collapse, pressure may be applied to the inside of the casing with the use of a packoff head.

The principal advantages of using stab-in equipment are listed below.

- Greatly reduces displacement volumes and time
- Wastes less overdisplaced cement when cementing to surface
- Decreases the need for extended-working-time cements
- Contributes less contamination because of reduced area and turbulent velocities in the drillpipe

11-5.8 Shoe and collar shell design

The shell is the outer steel portion of a cementing shoe and collar (Fig. 11-58). It becomes an integral part of the casing and must be capable of meeting chemical, dimensional, and strength requirements. Aside from an API threading standard, Specification for Threading, Gauging, and Thread Inspection of Casing, Tubing, and Line Pipe Threads (API Spec 5B), there are no specific industry standards covering shoe or collar shells.

Most float shoe and collar shells are made from collar stock, which is made from the same alloy composition as casing. The OD of this equipment generally conforms to API collar OD standards.

Shoe and collar cases are usually made of low-alloy or carbon steels such as API K55 or N80 and are suitable for H₂S applications. To prevent interference and allow use over a broad range of casing weights, shoe and collar internal and external diameters generally conform to the lightest-weight API casing drift and coupling external diameters, respectively. This also pro-
vides a heavier than usual wall, which allows use of low-strength steels, such as K55, to meet N80 burst and collapse pressures. Because of the lack of pressure differential across the shoe, general-purpose shoes are considered suitable for use with high-strength casings. Some manufacturers offer a heavyweight range to more closely match internal diameters and to improve external thread strengths. Table 11-4 shows the pressure ratings of various float collars.

General-purpose equipment is most readily available with API 8-round and buttress connections. To allow makeup to either API long or short connections, 8-round equipment is usually provided with API long internal threads and short external threads where applicable. External thread joint strengths may be as low as that of lightweight K55 casing but are generally adequate for bending and tensile stresses at the lower end of the casing. Some manufacturers offer double-box (internal thread) collars, which eliminate the weak part, the external thread. Premium threads are not commonly stocked and may require an extended delivery time.

### 11-5.9 Cementing plugs

*Cementing plugs* are semirigid barriers used to separate cement slurry from drilling fluids, to wipe the casing, and to indicate when cement placement is complete. Plugs were once made of gunnysacks, wood, and leather. Present designs include top and bottom plugs constructed of nitrile or polyurethane molded over PDC-drillable high-density plastic cores (Fig. 11-59). Most plugs are designed to be nonrotating; as a result, they are easier to drill out (Fig. 11-60).

| Table 11-4. Nonrotating Standard Float Equipment Ratings†, ‡ |
|-----------------|-----------------|-----------------|-----------------|
| Float Collar Size (in.) | Model 1 | Model 2 | Model 3 |
|                  | Plug Bump Pressure Rating (psi) | Back Pressure Rating (psi) | Plug Bump Pressure Rating (psi) | Back Pressure Rating (psi) | Plug Bump Pressure Rating (psi) | Back Pressure Rating (psi) |
| 7               | 5,000          | 5,000          | na³ | 8,000 | 5,000 |
| 7⁷⁄₈            | 5,000          | 5,000          | na | na  | 8,000 | 5,000 |
| 8⁵⁄₈            | 5,000          | 5,000          | na | na  | 8,000 | 5,000 |
| 9⁴⁄₈            | 5,000          | 5,000          | na | na  | 5,000/8,000 | 5,000 |
| 10³⁄₈           | 4,000          | 4,000          | na | na  | 6,000 | 5,000 |
| 11³⁄₈           | 3,300          | 3,600          | na | na  | 5,000 | 5,000 |
| 13³⁄₈           | 3,200          | 3,600          | na | na  | 5,000 | 5,000 |
| 16              | na            | na            | 2,000 | 2,000 | 3,000 | 2,000 |
| 18³⁄₈           | na            | na            | 1,500 | 1,700 | 3,000 | 1,700 |
| 20              | na            | na            | 1,500 | 1,700 | 3,000 | 1,700 |

† To meet API RP 10F - Classification IIIC requirements.
‡ Courtesy of Weatherford International
³ Not available
Although similar in external appearance, top and bottom plugs differ considerably in internal design and operation (Fig. 11-61). Bottom plugs were developed to precede the cement slurry, requiring an internal bypass or flow-through feature. The bottom plug features a thin membrane that is designed to rupture and permit flow once the bottom plug has seated (usually on the float collar). Bottom plugs also provide a seat for landing top plugs and sealing off displacement. To ensure compatibility, top and bottom plugs and float equipment should be from a common manufacturer. The use of bottom plugs with high LCM concentrations in the slurry can be risky, because the LCM may tend to ball up ahead of the wiper plug and bridge the float valve.

More recently, using a third wiper plug has become more common. The extra plug separates chemical washes or spacers from the drilling mud, keeping the preflushes clean before they enter the annulus. A second use of the third plug is to measure displacement efficiency of the mud pumps. Because of casing-ID variances and pump-liner inefficiencies, the displacement volume sometimes varies from job to job. With a three-plug system, the exact number of pump strokes necessary to bump the plug can be measured before pumping the cement slurry. This allows operators to pressure test the casing while the cement slurry is still fluid without damaging the cement-to-pipe bond.

Top plugs are occasionally used alone. They are designed to withstand the pressures and forces generated when landed abruptly. When both top and bottom plugs are used, it is vital that they not be launched out of sequence. Because of the exterior similarity, top and bottom plugs are generally color coded. The consequence of pumping the top plug first is that it will land and not rupture, leaving the casing full of cement. If this happens, the only recourse is to drill out the casing.
Other common plugs include the following:
- tapered plugs, used in multiple-ID strings
- subsea plugs, used with subsea completions
- latch-in plugs, used with latch-in equipment
- flexible-fin plugs, used when passing through stage equipment.

Figure 11-62 shows one of the newest large-bore subsea wiper-plug-set designs. The new sets come with built-in swivel equalizers and are released with darts instead of balls. The reason for dart release is to provide wiping of the drillpipe strings on deep casings or liners and to avoid having to wait for the gravity settling of balls. The operational sequence is illustrated in Fig. 11-63.
11-5.10 Stage equipment

Stage equipment, consisting of stage collars and port collars, is placed within the casing string to provide an intermediate passage to the annulus (Fig. 11-64). The collars are generally made of match-grade steel. They may be available in special weight ranges to optimize strength and internal dimensions. Stage equipment is generally used to protect weak formations from excessive hydrostatic pressure, to cement widely separated zones, and to reduce mud contamination.

Stage collars are available in both mechanical and hydraulic versions. However, even the mechanical method of opening and closing requires hydraulic force. Mechanical tools are opened and closed using free-fall plugs or pumpdown-closing plugs to select and shift the appropriate internal sleeve(s) (Fig. 11-65). The lower sleeve initially covers the ports. Once the first stage is complete, the lower sleeve is pumped down to uncover the ports by seating the free-fall (or pumpdown) opening plug and applying pressure. The second stage is pumped and the ports are closed again by seating and applying pressure to the larger closing plug. Once closed, the stage collar cannot be reopened. The pressure required to open and close varies with manufacturers, but it is generally between 800 and 1,400 psi [5.5 to 9.7 MPa]. When two stage collars are used, a special upper stage collar is required, and care should be taken to release the correct plugs in the proper sequence. The ID of the upper stage collar seats must be larger than the lower collar seats. For highly deviated holes, the free-fall dart should be replaced with a pumpdown plug. Drilling is required to remove the plugs and aluminum seats.

Figure 11-66 shows the mechanical stage tool in the run-in position, the opened position, and the closed position. Figure 11-67 shows the plugs and opening devices used to operate the stage tool. As a rule, all stage tools should be opened as soon as the primary job is completed, because any cement slurry above the tool can be circulated out.
**Running position**
Pin and box threads are identical to the casing threads. Stage collar integral connection is designed for gas tightness. Seals on opening sleeve provide internal and external pressure integrity across the fluid ports.

**Opened position**
Opening device has landed and, after pressure is applied, the lower set of shear mechanisms is broken and the sleeve shifts downward to uncover the fluid ports. Pumping operations can now be conducted through the stage collar.

**Closed position**
The closing plug has landed and, after pressure is applied, the upper set of shear mechanisms is broken and the sleeve shifts downward, shutting off the fluid ports. Double seals above and below the ports provide pressure integrity.

*Fig. 11-66. Mechanical stage tool shown in run-in, open, and closed positions (drawings courtesy of Davis-Lynch, Inc.).*
Two-stage cementing using a first-stage sealing plug, free-fall opening device, and closing plug

1. A float shoe, float collar, and stage collar are installed in the casing string and the casing is run to bottom.

2. Circulation is established and first-stage cement is mixed and pumped.

3. The first-stage sealing plug is launched and the cement is displaced. At the conclusion of displacement, the first-stage sealing plug lands and effects a seal against the float collar. No baffle is required.

4. The free-fall opening device is dropped and allowed to gravitate to position. Pressure is applied to the casing and the stage collar is opened.

5. Circulation is established and second-stage cement is mixed and pumped.

6. The closing plug is launched and cement is displaced. At the conclusion of displacement, the closing plug lands and effects a seal in the stage collar. Pressure is applied to the casing and the stage collar is closed.

Two-stage cementing using a bypass plug, shut-off plug and baffle, free-fall opening device, and closing plug

1. A float shoe, float collar, and stage collar are installed in the casing string and the casing is run to bottom. The shut-off baffle is installed in the casing string at least one joint above the float collar. If API threads are run (8-rd or buttress) the baffle can be installed in the “J” section of a coupling. If premium threads are run, a separate baffle collar must be run.

2. After the hole is conditioned, the bypass plug with the nose piece is launched ahead of first-stage cement. This plug will pass through the shut-off baffle and land on any manual- or self-fill float collar. Once landed, approximately 50 psi will invert the wipers on the bypass plug and allow cement to pass.

3. After cement is mixed and pumped, the shut-off plug is launched and cement is displaced. At the conclusion of displacement, the shut-off plug lands and effects a seal in the shut-off baffle.

4. The opening of the stage collar and the ensuing second-stage cementing and closing of the stage collar are carried out identically to that described for two-stage cementing with first-stage sealing plug.

**Fig. 11-67.** Plugs and opening devices used to operate stage tools (drawings courtesy of Davis-Lynch, Inc.).
One of the most common causes of stage tool failure is the inability to close the tool. The correct pressure to close most tools is related to the lift pressure of the second-stage cement column plus the shear strength of the pins holding the sleeve open. For example, suppose an operator is displacing second-stage cement before the closing plug bumps at 600 psi [4.1 MPa]. If the tool is set to close at 1,200 psi [8.3 MPa], then the pump pressure should be raised to at least 1,800 psi (1,200 + 600 = 1,800 psi [12.4 MPa]).

*Hydraulic stage tools* do not require a free-fall plug or pumpdown plug to open the tool. The tool opens when the shutoff plug bumps against either a float collar or landing collar. Then, the pressure can be increased slowly until it reaches a preset shear-pin rating in the stage-tool opening sleeve. The hydraulic stage tool has an internal sleeve much like the differential sleeve, meaning it has a larger area inside the tool on the upper end than the lower end (visible in Fig. 11-68 in orange color). This differential area, combined with the increasing pressure, keeps the tool closed until the internal area of the tool is pressurized, usually around 700 to 1,000 psi [4.8 to 6.9 MPa]. During the cementing process, the cement slurry takes the path of least resistance, following the mud out of the stage tool ports and up the annulus. The operating sequence is shown in Fig. 11-69.

There are optional methods for opening a hydraulic tool with a free-fall plug, and there are special plugs that can be used to open or close the tool if required. These options are available because some operators run stage tools only as a contingency, and if they do not want to use them, they must be able to close them after the job.
Fig. 11-69. Hydraulic stage tool operational sequence (drawings courtesy of Weatherford International).
Liner stage tool options
When running stage tools or annular casing packers (ACPs) on liners, it is difficult to reliably open and inflate the tool with standard liner wiper plugs. Figure 11-70 shows a special plug set that works with most liner systems in conjunction with hydraulic stage tools and ACPs. This system is sometimes referred to as a four-plug system, but it is actually two darts and two plugs. The lower dart launches the lower plug and displaces the primary cement, landing on a special plate. Then pressure builds up, inflating and locking the ACP. Further pressure build-up opens the hydraulic stage tool.

Port collars are another type of stage tool, mechanically operated from the surface by a tool connected to an inner string of drillpipe (Fig. 11-71). They are available with sliding or rotational valve mechanisms and may be opened or closed as often as necessary. Lock-down options are also available. The sliding valves are generally opened with an upward motion and closed with a downward motion; they require a minimum of 10,000 lbf [44 kN] to stroke. Port collars may be placed as often as necessary in the casing string and selected in any sequence. There are no plugs to use or drillout required. Some shifting tools may be fitted with cup-type seals to form a conduit from the inner string to the ports.

Stage collars and port collars must be handled with care because of the close tolerances between the outer body and the internal sleeves. Tongs or makeup equipment should not be placed in the midbody of a stage collar but rather on the coupling ends, where there are no thin-walled sleeves.

Centralizers and baskets, or annular casing packers (ACPs), are often used with stage equipment. Cement baskets or ACPs are placed below the stage collar to help support the hydrostatic pressure of the next stage and to prevent cement from falling through lower-density fluids below.
11-5.11 Annular packoff equipment

ACPs (also known as external casing packers) are popular because they provide improved sealing and centralization. They are used to prevent gas migration, reduce the gas-to-oil production ratio, reduce or prevent water production, isolate production or injection zones, and avoid squeeze cementing.

ACPs vary in size and valve type depending on their purpose. Most can be filled with mud or cement, but the amount of pressure they can withstand is limited. Overfilling is a major cause of casing packer failures. Two types of ACPs are shown in Fig. 11-72.

Annular packoff equipment (packer shoes, collars, and ACPs) is used to protect areas of the formation from excessive hydrostatic pressure, contaminating fluids, or both. The equipment has expanding rubber elements that pack off against the formation to create an impermeable annular barrier. The rubber elements also centralize the casing when expanded.

ACPs are generally used below stage collars or port collars to protect the formation below from excessive hydrostatic pressure or contamination (Fig. 11-73). They are also used in an attempt to block gas and fluid migration. ACPs can be installed on either side of a weak formation.
Fig. 11-73. Typical stage cementing collar (drawings courtesy of Davis-Lynch, Inc.).
ACPs can be packed off by either inflating or compressing the rubber element (Fig. 11-74). The inflatable type is generally larger and more capable of packing off oversized or irregular holes. The inflation process generally begins at a predetermined setting pressure. The setting pressure should be sufficiently high to prevent premature packoff while conditioning or cementing.

An optional break-off rod may be used to prevent premature setting by blocking the inflation port until broken free by a wiper plug. Once the element is inflated, an internal valve mechanism will hold the inflated position, and the surface pressure may be released. When possible, the element should be inflated with cement.

Packer shoes and collars are hydraulically set by a tripping ball (Fig. 11-74). With the casing in place, the tripping ball is dropped and allowed to fall to a seat on the piston. As pressure is applied, the load is transferred to an external sleeve that compresses and expands the element. At a pressure of approximately 800 psi [5.5 MPa], the piston shears free, uncovering the ports. The external sleeve contains a ratchet mechanism that permanently holds the set position. The cement is pumped and, unlike stage equipment, the ports are not closed.

Basket shoes use a basket instead of an expanding rubber element to pack off the annulus. They provide the same function as a packoff shoe but are limited to low differential pressure applications and do not create a true hydraulic seal.

11-5.12 Cement displacement enhancement tools

External casing attachments increase the chances of achieving a successful primary cement job. The most common devices are centralizers, baskets, and scratchers, described in this section.

Stop collars are used to hold or limit the travel of the external attachments. (Fig. 11-75). They should be used instead of welding the attachments, which may be harmful to the casing. Stop collars are available in solid or hinged designs and may be fastened with bolts, set screws, or hammer-locking mechanisms. Stop rings for high-strength casing applications should contain hardened inserts to better grip the casing. Care should be taken to prevent dropping loose articles into the hole, and all tools should be installed on the pipe rack before the pipe is shipped to the location.

On critical wells, time should be taken to make sure the stop collar matches the well conditions. It is critical in most cases that the centralizers be supported and pulled into the wellbore. Typical stop collars such as the

![Fig. 11-74. Typical packoff float shoe (drawing courtesy of Weatherford International).](image-url)

![Fig. 11-75. Stop collars (photographs courtesy of Weatherford International).](image-url)
older friction clamps (nut and bolt types) have a gripping force of slightly more than 10,000 lbf [44 kN], whereas the set-screw stops have gripping forces up to 35,000 lbf [156 kN] with proper installation. The gripping force of insert-type stop collars can exceed 60,000 lbf [267 kN] and are easier to install than most set-screw stop collars. Of course, the price is directly proportional to the gripping force. Purchasing high-quality centralizers and then installing them with inferior stop collars is a waste of money.

Casing centralizers (Fig. 11-76) are one of the simplest yet most beneficial mechanical devices used in primary cementing. They are designed to position the casing more centrally in the hole and provide the following benefits.

- Reduce drag and differential sticking while running casing
- Improve
  - mud removal
  - cement placement, creating a more uniform wall thickness
  - performance of other external devices, such as scratchers and baskets

To be effective, centralizers must be properly placed with respect to spacing and location within the string. Spacing is a function of several parameters, such as casing size, hole size, deviation, and all factors relating to the side forces and drag. Most cementing and service companies use computer software to determine optimal centralizer spacing and placement (Chapter 12). The software requires one to input pipe and well data, including casing size, casing weight, casing seat, hole size, and mud weight, and, when deviation is present, full survey data, including kickoff point, rate of build, and final deviation. Because centralization is most critical through the cemented interval, the anticipated top of cement must also be provided. With these data, the computer can run centralizer spacing and standoff programs in two modes. The first and more effective mode is variable spacing, in which the relevant well data are entered and the computer calculates both the number of centralizers to run and how to space them to achieve the desired standoff along the cemented interval. The second mode is constant spacing, in which the program calculates the standoff that can be expected for a given number of centralizers across the cemented interval. A typical computer output is shown in Fig. 11-77.

The type, fit, and strength of a centralizer are important factors to consider. There are three basic types of centralizers—rigid, semirigid, and spring bow.

Rigid centralizers are built with a fixed bow height and are sized to fit a specific casing or hole size. The rigid centralizer bows can be solid cast metal, such as aluminum (Fig. 11-78) or iron, molded plastics and phenolic resins, or even machined composites. They also can be made from solid, tubular, or T-bar steel members that are welded together (Fig. 11-79). The side loadings on a given wellbore dictates to what extreme the operator must go to centralize the pipe. For example, on a riser tieback string, one would not use a 13¾-in. rigid centralizer that may be exposed to helical buckling loads of 50,000 to 100,000 lbf [222 to 445 kN], well beyond the capabilities of any spring-bow centralizer. This situation could also overload the compressive strength of most plastic, aluminum, or tubular rigid centralizers. A centralizer built out of solid steel bar or cast iron would be able to meet the requirements. Centralizer choice involves matching loading with restoring force or resistance.

Fig. 11-76. Collection of casing centralizers (photograph courtesy of Weatherford International, Inc.).
Typical 9%\%-in. Centralizer Application Analysis

<table>
<thead>
<tr>
<th>Casing size: 9.625 in.</th>
<th>Well Data:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mud density: 9.200 lbm/gal</td>
<td>Casing weight: 43.50 lbm/ft</td>
</tr>
<tr>
<td></td>
<td>Casing seat: 6,300 ft</td>
</tr>
<tr>
<td></td>
<td>Hole size: 12.250 in.</td>
</tr>
<tr>
<td></td>
<td>Kickoff point: 5,300 ft</td>
</tr>
<tr>
<td></td>
<td>Rate of build: 10°/100 ft</td>
</tr>
</tbody>
</table>

Constant Spacing Summation with Spring Bow Centralizers

- Spacing: Constant
- Number of Centralizers: 39

Variable Spacing Summation with Spring Bow Centralizers

- Spacing: Constant
- Number of Centralizers: 53

Variable Spacing Summation with New Semirigid Bow Centralizers

- Number of Centralizers: 35

Well Data:
- Casing weight: 43.50 lbm/ft
- Casing seat: 6,300 ft
- Hole size: 12.250 in.
- Kickoff point: 5,300 ft
- Rate of build: 10°/100 ft
- Final deviation: 89°

Conclusion: Projected standoff inappropriate for cement emplacement. Note no standoff at all through build section.

Projected standoff before cement emplacement compares favorably with API specification for centralizer performance.

Fewer units project comparable standoff to that of conventional spring bows while effecting reduced casing drag and installation time.

Fig. 11-77. Casing centralizer computer analysis (courtesy of Davis-Lynch, Inc.).

Fig. 11-78. Spiral-bladed rigid centralizer (photograph courtesy of Ray Oil Tools).

Fig. 11-79. Rigid centralizer (photograph courtesy of Weatherford International).
A problem with rigid centralizers is that they must be smaller than any restrictions they must pass through; consequently, the amount of standoff is limited. Figure 11-80 is a plot showing the amount of standoff achieved by rigid versus spring-bow centralizers (discussed later). At low loading forces, the spring-bow centralizer will give a better standoff. In high-loading situations, such as a kickoff section of a deviated wellbore, the rigid centralizer may give a better standoff.

Semirigid centralizers are relatively new and have most of the attributes of the rigid centralizer in that they can withstand high side loads. However, when forced into a loading situation greater than their capability, the bows collapse without destroying the centralizer integrity and without leaving loose parts in the hole.

An example would be a semirigid centralizer built for 9¾-in. casing. The centralizer has an OD of 12 in. and is run into a 12¼-in. open hole. If the centralizer passes a swollen shale section during the running process, the bows can collapse to a degree sufficient to allow the centralizer to pass through. Further movement would have been prohibited if a rigid centralizer had been run.

Semirigid centralizers are most often a type of stamped steel-alloy bow that is part of the solid body or welded on to end rings (Fig. 11-81). Most other materials are not acceptable because of potential cracking of the materials under high stress. Examples of semirigid centralizers are shown below.

Spring-bow centralizers are more commonly used. They are constructed of spring steel bows with an OD greater than the hole in which they are run. These bows must be flexible, yet sufficiently stiff to provide adequate standoff in various hole shapes and diameters. They are available with low or tall bow heights for slim or oversize holes, respectively. The most common bows are those that are straight or aligned with the long axis of the casing on which they are mounted (Fig. 11-82).
Other bows may be placed in a helical pattern (spiral-bow centralizers) to aid mud removal while running. Some have thin angled blades beneath the bows and are able to induce turbulence and aid mud removal (Fig. 11-83). Such devices are known as centralizers with fins or turbolizers.

Although most spring-bow centralizers are similar in appearance, subtle differences in bow or hinge thickness or the lack of proper heat treatment may considerably reduce their performance or strength. There are dozens of primary bows readily available from various suppliers and hundreds of other specialty bows built for specific requirements.

Today, many engineers specify the tandem rise or double bow centralizer because of its superior ratio of starting force to restoring force (Fig. 11-84). Generally speaking, one should select a centralizer that provides the maximum restoring force with the least possible amount of drag.

To establish minimum strength requirements and a basis to determine the centralizer spacing, the API created the Specification for Bow-Spring Casing Centralizers (API Spec 10D). This specification defines strength requirements and methods of testing for standard and close-tolerance centralizers.

Close-tolerance centralizers are designed for casing-hole clearances less than 0.75 in. per side. Spring-bow centralizers can be made to fit tighter casing/hole combinations, but it can be difficult to keep the centralizer in place while running casing. If the centralizer slips, it will move up to a coupling or some other obstruction on the casing string. Then, the longitudinal compression forces will exceed the centralizer’s strength and the centralizer will deform and generate more drag. In some cases, the centralizer may fall apart. Either situation may prevent further downward movement of casing. The slippage of centralizers occurs most frequently in tight annular conditions or where the centralizer is not providing adequate standoff to prevent the stop collar from scraping along the annulus.
To overcome this problem, several companies have developed a new type of centralizer called the centralizer sub (Fig. 11-85). The purpose of the centralizer sub is to allow the spring-bow centralizer to compress while running through hole sections that are only large enough for the casing connectors. After passing through the restrictions, the spring-loaded centralizer bows pop back out and continue centralizing the pipe.

The standard centralizer sub is built from float equipment collar stock, much like the float collar shell. The entire OD is the same size as the connection couplings. Where the centralizer is installed on the sub, the OD is again reduced to produce a reduced slot for the end collars and the bows. These slots are produced by milling the OD out instead of welding on any rings, which would compromise the shell body properties. The OD of the compressed centralizer should be no larger than the casing coupling. Centralizer subs with rigid blades are available but have a limited benefit when dealing with under-reamed wellbores.

When installed over stop collars, casing couplings, and some centralizer subs, the centralizer is designed to be pulled into the wellbore. This is the optimal way to move it downhole with the least drag or damage to any parts. One reason that stop collars occasionally fail on close-tolerance centralizers is that the dimensions (thickness) do not allow the stops to fit under the centralizer bows at full compression. If this restriction is known before the job, the centralizers may be run with stop collars on either end of the travel area; however, this can increase the drag as the centralizer is pushed into the wellbore.

Pushing a spring-bow centralizer compresses it lengthwise. This tends to cause the bows to expand outward, increasing drag. When possible, centralizers should be installed so that they are pulled by the casing rather than pushed. This reduces the chance of centralizer damage caused by hanging. Pulling is accomplished by placing a stop ring or lug within the centralizer collars.

In large or oversize hole conditions, centralizers may be placed over couplings (but not couplings that have an OD greater than 1 in. more than the pipe size), provided the couplings do not interfere with bow deflection (compression). Most close-tolerance centralizers are designed with low profiles and should not be placed over stop rings or couplings that may contact or interfere with the bows. The most common gripping method is to install set screws into the collars of close-tolerance centralizers.

Standard spring-bow centralizers are available with solid or hinged collars. The hinged style is the simplest to install and is most often used. Solid-collar centralizers are recommended for close-tolerance conditions (typical of liner applications), because they are generally stronger and cause less drag resistance.

**Torque- and drag-reduction centralizers**

As high-angle or horizontal wellbores have become more common, the need for drag reduction during running casing has become a major priority in casing accessories. Special coatings for spring-bow centralizers were originally used, but this method had limitations (temperature and abrasion). The next evolutionary step was to integrate rollers with the solid blade centralizers (Fig. 11-86).
The first roller tools had tangential rollers and axles mounted perpendicular to the pipe. The next generation of roller tools had axial and tangential rollers. This change was intended to reduce drag and torque while moving pipe. The axial rollers are arranged to contact the pipe inside the centralizer, allowing the centralizer to remain stationary while the pipe rotates inside.

At this writing, the record for the longest rotated liner in a high-angle wellbore was achieved in the Wytch Farm field (United Kingdom). The approximate vertical depth was 5,000 ft, and the total measured depth was slightly greater than 31,000 ft. Overcoming torque and drag to insert the liner to TD was a major accomplishment, and rotation was performed for more than 10 hr while the hole was circulated and cemented.

**Other casing-mounted cementing devices**

*Scratching devices* are external devices designed to remove immobile mud from the wellbore and mudcake from the wellbore wall (Fig. 11-87). These devices are categorized by how aggressive they are. The basic spring-loaded bristle scratcher is more aggressive than the cable scratcher (also known as a wellbore wiper). Scratchers are also designed for casing reciprocation and rotation. Reciprocating devices, consisting of a collar with radial wires or cables, are designed to remove mud during pipe reciprocation. The up-and-down movement causes the wires or bristles to disturb the wellbore wall. Rotating devices are straight strips of steel containing longitudinal wires or cables. They are attached lengthwise to the casing to remove mud while rotating.

Scratchers and wellbore wipers are most effective when the casing is centralized and manipulated before and during cementing. To prevent solids or mudcake buildup, scratchers should be spaced to ensure overlapping of areas worked by adjacent scratchers. It is very important that circulation be established before pipe movement. Reciprocating scratchers may be allowed to float between the stop collars. Rotating scratchers are attached with special clamps that are usually different from normal stop collars.

The use of scratching devices has declined in recent years. The problem is not related to their effectiveness—sometimes they work too well. Mud filtercake that is removed from the wellbore wall while running the pipe adds solids to the displaced mud column and increases fluid loss to the formation as the cake is rebuilt. Both of these occurrences increase the hydrostatic pressure exerted by the fluid column.

Scratchers are most effective when the engineer takes their effects into account. About every 10 to 15 joints of pipe, one should stop and circulate the annulus to move the displaced solids up into the previous casing or to surface. During the cement displacement process, pipe movement is still important because cement filtercake takes the place of the removed mud filtercake.

*Cementing baskets* are used in low-differential-pressure applications to separate fluids and to help support the hydrostatic pressure of the cement slurry. Cement
baskets are not an annular seal and they should never be used to replace an ACP. They exist simply to offer a restriction to wellbore fluids that tend to intermix because of their different densities.

One place to use a cement basket would be 10 ft directly below a stage tool. After the second-stage cementation is completed and the stage tool is closed, the heavier cement slurry will tend to drop into the lighter fluid below the stage tool. The baskets can help prevent this occurrence by inhibiting flow. Baskets are typically constructed of thin steel petals arranged in an overlapping pattern (Fig. 11-88). Cement baskets are available in both the half-basket and whole-basket configurations, and both are installed over a stop collar (usually a set screw).

The packoff or barrier is formed as the petals spread to fit the hole, creating a sort of upside-down umbrella within the annulus. Cement baskets were not designed to be reciprocated rapidly, and they will not lift the cement column during reciprocation. Experience has shown that reciprocation can turn the baskets inside out and destroy them. Casing rotation is possible with planning and the right type of stop collar.
Baskets are most effective when centralized and placed in a gauge section of the hole. Most baskets are not hinged and must be slipped onto a joint of casing before makeup with the stop collar inside. The position of the stop collar inside the basket allows the basket to remain stationary while picking pipe out of the slips during running.

11-6 Liners

11-6.1 Introduction

A liner is a string of pipe made from conventional casing or tubing. Unlike conventional tubulars that are hung from the wellhead, a liner is hung from a previously set casing string (Fig. 11-89). The distance between the top of the liner and the wellhead can be from less than 50 ft [15 m] to several thousand feet.

A liner is lowered into the wellbore using the drillstring. This is normally drillpipe or tubing, but in some cases, the liner is lowered into position using coiled tubing.

11-6.2 Liner types

There are four basic liner categories (Fig. 11-90).

**Drilling or intermediate liner.** This type of liner is normally run to cover a weak or troublesome formation that impedes further drilling operations. After the liner is cemented in place, drilling to a deeper zone proceeds.

**Production liner.** A production liner is run across a zone of interest or a producing zone. These liners can be cemented in place like drilling liners or consist of predrilled or screen-wrapped tubulars that are not cemented in place.

**Scab liner.** A scab liner is a section of casing or tubing for repairing damaged casing. This liner is normally run in old wells but may be placed in new wells in which tools or the drillstring has worn through or damaged the previous casing string. The scab liner can be run to repair the leak and/or damage. Short scab liners are often not cemented in place; instead, they are frequently run in place with a packoff seal at the top and the bottom.

**Scab tieback liner.** A section of casing that extends upward from the top of an existing liner but does not reach the surface is called a scab tieback liner.
11-6.3 Reasons for installing a liner
There are many reasons why a liner is installed in a well. Some are related to the well. Others involve logistics, rig-handling capabilities, wellhead design, drilling cost reduction, or contingency plans when drilling through unknown formations or encountering unexpected difficulties.

When a liner is run, the openhole section below the previous casing string can be cased off more rapidly. The liner is run on the drilling string, not on individual tubular sections reaching to the wellhead. This saves rig time and allows the string to be quickly placed across sensitive or weak formations, possibly preventing the openhole section from caving in. In addition, because the liner is set on bottom or hung from the previous casing string, the weight of the liner is not borne by the wellhead.

Liners are usually much shorter than a conventional long string; therefore, they are easier to manipulate (i.e., rotation, reciprocation, or both) during the cement job. Such movement can greatly improve cement bonding (Chapters 5 and 13).

Normally, cement slurries are more dense than the drilling fluid. The increased hydrostatic pressure can lead to lost circulation (Chapter 6). When liners are used, the height of the cement-slurry column is shorter, the hydrostatic pressure is lower, and the probability of lost circulation is reduced.

Because liners are shorter than conventional long strings, the pressure surge (piston effect) that occurs while they are run into the hole is less severe. This also decreases the chances of lost circulation.

The tubular section that comprises the liner string normally weighs more than the drillstring. Therefore, deeper wells can be drilled with smaller rigs, because of the decrease in overall string weight. Also, large rigs can drill wells beyond 30,000 ft [9,140 m]—a feat that cannot be accomplished with conventional casing strings run all the way back to the wellhead on conventional drilling rigs.

The section of casing above a liner has a larger ID than the liner. This allows more flexibility in the type of completion equipment run in the well. The larger uphole ID permits larger completion strings and, in most cases, increased well productivity.

With conventional casing strings, one may eventually reach a point at which the drillpipe will no longer fit inside the next casing size. This forces the operator to switch to a smaller-size drillstring. Installing a liner allows the operator to lay down only a portion of the string. The original drillstring can still be used above the liner, saving time and money. Liners allow sidetracking during the drilling process without losing hole size.

11-6.4 Principal components of a liner
Most conventional cemented liners consist of five segments that run from the rig floor to the bottom of the well (Fig. 11-91).

1. Surface cementing equipment
2. Liner setting tool assembly
3. Liner setting sleeve/liner top packer assembly
4. Liner hanger
5. Shoe track assembly

Throughout this discussion about liners, the reader will often be referred to Fig. 11-91 to clarify the location of the various components. For example, Fig. 11-91[2] refers to the liner setting tool assembly.

Fig. 11-91. Segments of a liner (drawing courtesy of Baker Oil Tools).
11-6.4.1 Surface cementing equipment (Fig. 11-91[1])

The surface equipment is located on the drilling rig floor. It connects the running string to the block of the rig and connects the displacement, circulation, and cementing unit lines to the drillstring. The surface equipment holds the displacement plugs and setting balls for hydraulically operated tools downhole. There are two types of cementing heads for running liners. The first (Fig. 1-92) is used for conventional drilling rigs and the other is used for drilling rigs that operate with a topdrive system (Fig. 11-93). This equipment allows total control of the weight set on the liner, because the surface cementing equipment carries the string weight at all times during the cementing and liner-installation operations.

Fig. 11-92. Plug-dropping cement head for conventional drilling rigs (drawing courtesy of Baker Oil Tools).

Fig. 11-93. Cement head for topdrive drilling system (drawing courtesy of Baker Oil Tools).
In some parts of the world, local regulations require the cementing heads to be operated directly from the rig floor. For these areas, a remotely controlled pneumatic version of the cementing head is used. The remote-control panel is shown in Fig. 11-94.

![Control panel for pneumatically operated plug-dropping head](drawing courtesy of Baker Oil Tools)

Pneumatically operated surface equipment is also used in areas where rotating liners are run on a regular basis. With conventional systems, it is a safety standard to stop the rotation when the displacement plugs or setting balls are being launched. Resuming liner rotation after stopping may be difficult or impossible. The pneumatic design permits continuous rotation of the liner, enhancing the safety and efficiency of the liner-cementing operation.

11-6.4.2 Liner setting tool assembly (Fig. 11-91[2])
The liner setting tool assembly is a retrievable device that connects the drillstring to the top of the liner. In the 1930s, it was most commonly known as the “letting-in tool,” and mainly consisted of a modified casing release spear. Today, the setting tool is run with a liner setting sleeve or liner top packer (Fig. 11-91[3]) with a corresponding setting tool profile. Together they perform several key functions during the liner running and cementing operations.

- Support the weight of the liner while running in the hole
- Allow the operator to push, pull, and circulate freely until ready to disconnect
- Provide a reliable releasing mechanism to detach the running string once the liner is at the desired position in the well [this can be done mechanically (Fig. 11-95), hydraulically (Fig. 11-96), or both, depending on the type of running tool used]
- Allow rotation of the liner before and after the drillpipe has been disconnected from the drillstring
- Provide the ability to set liner top packers after the setting tool is released
- Provide a seal between the drillpipe and the liner while running the liner in the well and during the cement job (diverting the fluid to the bottom of the liner while circulating)

![Mechanical liner running tools](drawings courtesy of Baker Oil Tools)
When the liner is run with a liner top packer (Fig. 11-91[3]) at the top of the liner string, an additional device is required in the liner setting tool assembly. This tool is usually called a packer-setting dog sub (Fig. 11-97).

As explained above, the liner setting tool assembly not only acts as the quick disconnect between the drillstring and the liners, but also creates a seal between the two strings. This seal is required to ensure that the fluid pumped at surface through the drillstring is pushed out of the bottom of the liner string. Together with a ball seat or temporary plugging device inside the liner, it can also create a temporary closed chamber at any time during the installation to activate hydraulically operated tools in the liner string. Some of these hydraulic operated tools are hangers (Fig. 11-91[4]), running tools (Fig. 11-91[2]), hydraulic casing packers, hydraulically operated openhole packers, and cementing-type valves located in the liner string.

Packoff assemblies come in a variety of models that can be categorized into four types. Each has its advantages and disadvantages according to the type of liner and the well conditions.
Cup seal system (Fig. 11-98). The cup seal system is an economical setting tool packoff for low-pressure and -temperature service. Normally, it only holds pressure from one side and is part of the liner setting tool assembly. Thus, it is retrieved after the job is finished and can be reused after it has been inspected and the cups have been replaced. The cup seal system provides an unrestricted liner top at the end of the cementing operation.

Drillable packoff bushing system. This system comprises one tool installed at the top of the liner and another corresponding tool at the bottom of the liner setting tool assembly, usually called a slick stinger. The tool run in the liner string is normally run between the liner setting sleeve or liner top packer (Fig. 11-91[3]) and the liner hanger (Fig. 11-91[4]). The drillable packoff bushing system (Fig. 11-99) creates a positive two-way seal at the liner top. Upward piston forces are greatly reduced compared to other seal systems, particularly when running large-diameter liners or liners at shallow depths, in which no drillstring weight is available to keep the running string in place while pumping fluids. The insert has bidirectional seals, is normally made of aluminum or composite material, and is drilled out after the liner cementing operation is completed. Sometimes this liner-top restriction can aid in highly deviated wells and where there is a possibility of excess cement settling out inside the liner.

Polished-bore receptacle (PBR) packoff system. The PBR packoff system (Fig. 11-100) has the same advantages as the cup seal system in that it leaves the liner fully open after the cement job. In addition, it has the high pressure and temperature bidirectional pressure capabilities of the drillable packoff bushing system. It consists of two components, one located at the bottom of the liner setting tool assembly and the other placed in between the liner setting sleeve or liner top packer (Fig. 11-91[3]) and the liner hanger (Fig. 11-91[4]).
Retrievable seal system. The retrievable seal system (Fig. 11-101) combines the advantages of the drillable packoff bushing system, in which there are very low pumpout forces, and the PBR packoff system with the bidirectional high-pressure, high-temperature seal and the unrestricted liner top at the end of the cementing operation. The retrievable section below the running tool is locked into a special profile sub at the liner top by a set of locking dogs. These dogs will transfer most of the upward forces back into the liner instead of placing them on the drillstring. At the end of the cement job, the dogs are allowed to collapse inwards, owing to a dedicated machined recess at the bottom of the slick stinger. This allows the retrievable seal system to be pulled out of the liner top, leaving the liner top fully open.

11-6.4.3 Liner setting sleeve/liner top packer assembly (Fig. 11-91[3])

The liner setting sleeve is the “crossover” between the liner setting tool assembly (Fig. 11-91[2]) and the liner string itself. The upper profile or thread matches that of the liner setting tool assembly (Fig. 11-91[2]), and the bottom thread and ID matches that of the liner tubular sections. Normally, most liner setting sleeves are manufactured with some type of tieback extension or PBR above (Fig. 11-102) and in some cases below (Fig 11-103) the liner setting tool profile.

This tieback extension or PBR is used to stab in a set of seals built on a seal mandrel with the same ID as the liner string. This seal mandrel can be integral to a tieback packer and used to repair liner-top leaks, run as a scab tieback liner, or used as a conventional tieback string that extends all the way back to the wellhead. In some complex liner completions, this tieback extension or PBR is designed as part of the completion.

In many cases, the overlap between the liner top and the bottom of the previous casing string is not long enough to create a proper cement seal at the top of the liner. A 500-ft overlap has been the industry standard; however, some operators and well conditions require the overlaps to be as short as 50 ft. In some wells, in which the adjacent formation is very weak, the cement will never reach the top of the liner; therefore, instead of relying upon cement alone, a supplementary seal should be used. For such applications, the liner setting sleeve is replaced by a crossover between the liner setting tool assembly and the liner string itself. The crossover fea-
atures a packing element that creates a seal between the liner top and the previous casing string. This liner top packer is normally set after the cement has been pumped in place. Other functions of the liner top packer include the following.

- After the liner has been hung and cemented in place, the liner top packer insulates the cement from the hydrostatic pressure of the drilling fluid and aids the backpressure equipment inside the shoe track (Fig 11-91[5]). As a result, the cement slurry is held in place until it sets.

- When excess cement above the liner top is reversed out, the liner top packer isolates the remaining cement slurry behind the liner from the pumping pressure, reducing the possibility of formation breakdown or loss of cement in the liner lap.

- If a poor cement job has occurred, the liner top packer serves as a seal around the top of the liner assembly.

Much has changed since the first liner top packers were introduced in the 1920s. The original devices were made of lead, canvas, and rubber elements. Even in the mid-1980s, only about 20% of the cemented liners were run with liner top packers owing to problems with the seal during the installation process. High circulation rates, temperature increases, and cuttings in the drilling fluid would damage or swab off the seal. Compression-type elastomeric seals and various types of backup rings have greatly improved the reliability of the conventional liner top packer (Fig. 11-104). In the early 1990s, a milestone was reached with the introduction of expanding metal technology to liner top packers (Fig. 11-105). These expanding seals can be run in the most rigorous environments and are typically not the weak link in the liner system. As a result, liner top packers are used in about 80% of liner installations today.

Liner top packers are also equipped with the same type of tieback extension as the conventional liner setting sleeve (Fig. 11-102). However, the tieback extension on a conventional liner setting sleeve is either threaded or part of the tool, while that on a liner top packer moves independently.
After the liner has been installed and cemented in place, the liner setting tool assembly is removed from the tieback extension. This exposes and activates the dogs on the packer-setting dog sub (Fig. 11-97). Slacking off to a predetermined amount of set-down weight will place weight on the tieback extension and not on the setting sleeve/liner system, because the dogs on the packer-setting dog sub (Fig. 11-97) cannot reenter the tieback extension. This will allow the packing element or expanding metal seal to move outwards against the tubular in which the liner is being run to create a seal.

11-6.4.4 Liner hanger
Liner installation and cementing techniques have improved since the early days. Initially, liners were installed by drilling the required openhole section below the previous casing string, and cement was placed in the openhole section. Liner joints were made up on the rig floor and allowed to fall freely in the well. The drillstring was used to push the liner into the cement before it set (Fig. 11-106).

The introduction of the liner hanger (Fig. 11-91[4]) in combination with the liner setting sleeve assembly (Fig. 11-91[3]) and the liner setting tool assembly (Fig. 11-91[2]) at the top of the liner string allowed liner placement in a more controlled manner. The liner...
hanger is basically a simple wedge or inclined plane and ensures that the liner will not collapse because of its own weight, become buckled, or shift position in the hole after it has been installed. The liner is suspended and cannot sink into the formation bottom, nor can it fall over into a cavity and lose alignment with the cased hole above. Being perfectly aligned with the axis of the hole and free of bending, the suspended liner is not subjected to undue wear from tools, rods, or tubing strings run through or operated inside the liner string. Initially, liner hangers were mechanically set, much like the device shown in Fig. 11-107, except that the 360° cone (Section 11-6.4.4.2) (Fig. 11-108) has been replaced with cone pads to increase bypass or flow area.
Hanger designs are influenced by several factors.

1. Annular dimensions. The available space between the liner OD and the casing ID in which the liner is to be run.

2. Annular area. Backpressure on the formation during circulation and cementing should be kept to a minimum. Multicone designs on conventional hangers increase the bypass area and provide higher load-carrying capabilities.

3. Casing grade, size, and wall thickness. The weaker the casing in which the liner hanger is to be set, the lower the liner weight that can be suspended from the hanger itself.

4. Length of the liner and liner top packer rating. Liner length is normally not a significant problem and is essentially unrestricted in most applications. Also, the rating of the liner top packer (especially in uncremented or partially cemented liner applications) must be taken into consideration when choosing a hanger type. Tubing with higher pressure ratings will add substantial weight to the hanger.

5. Setting. Unlike retrievable packers or other retrievable tools, most liner hangers and liner top packers are designed for a one-time operation. As a result, they are less expensive.

6. Pipe movement. Special rotating or reciprocating designs allow movement during the cementing operation to aid cement displacement. The first rotating liners were designed in the early 1950s but did not gain wide industry acceptance until the mid-1980s.

7. Hole bridging or collapsing. Where this problem occurs, drill-down liner hangers and systems are available.

8. Environment. Corrosive environments dictate the use of special materials or controlled hardness designs. This is more typical for production or completion rather than drilling liners.

9. Lost circulation. This is associated with the bypass area requirement. A hanger and liner top packer will help hold the cement until it sets. For conventional packers, the higher the rating of the liner top packer, the larger the OD will be; therefore, the annular clearance between the liner OD and the casing ID will be smaller. This can cause lost circulation.

10. Collapse, burst, and tensile requirements. These requirements may also dictate the type of hanger and liner top packer that can be used in environments in which pressure ratings must exceed 10,000 psi [68.9 MPa] and 500,000 lbm [2,220 kN] of load.

### 11-6.4.4.1 Predicting liner hanger capacities

There is no single method to accurately predict the liner load that a hanger will support, because many downhole and mechanical variables are not well quantified. Aside from downhole conditions, which naturally vary considerably, the friction factor for steel on steel will vary with the following:

- machined finish
- lubrication or films between surfaces
- vibration
- extent of contamination between surfaces
- yield strength and dimension of tools versus minimum yield and nominal dimensions
- condition of the tubular in which the liner hanger is to be set and the wellbore environment behind the tubular.

As mentioned previously, the liner hanger mechanism is a simple wedge or inclined plane. Formulas for determining the magnitude and direction of these forces are readily available in mechanical engineering handbooks. These formulas can be used as a starting point to estimate the maximum load that a liner hanger can carry. The most common workable solution relies heavily on the following:

- past successful performance and installations
- the use of conservative friction factors
- the use of conservative safety factors
- testing.

Pull tests are not more reliable than the formulas in engineering handbooks for predicting the actual loads that can be supported. In fact, relying solely on pull-through tests can be misleading, unless a large number of tests are conducted to establish validity.

Some liner manufacturers have translated the handbook formulas for a simple wedge for use as a starting point for designing multiple slips and cones to be installed on the hangers. The formulas are shown in Eqs. 11-2 and 11-3.

1. Maximum supported load \( F_{\text{max}} \) that the casing in which the liner hanger is to be set will withstand:

\[
F_{\text{max}} = p_{\text{burst}} EG,
\]

where

\( p_{\text{burst}} \) = burst pressure or internal yield pressure of casing in which liner hanger is to be set

\[
E = \left[ \frac{L \pi d_{\text{slip}}}{N_{\text{slips}}} \right] \times N_{\text{slips}}
\]
where:
\[ d_{\text{slip}} = \text{slip OD} \]
\[ L = \text{slip length} \]
\[ N_{\text{slips}} = \text{number of slips} \]
\[ N_{\text{slipseg}} = \text{total slip segments cut} \]
\[
G = \frac{\tan \alpha + \mu}{1 - \mu \tan \alpha}
\]

where:
\[ \alpha = \text{hanger cone angle} \]
\[ \mu = \text{coefficient of friction} \]

2. Maximum load that the hanger body (or liner joint on which the hanger is made) will support:
\[
F_{\text{max}} = p_{\text{col}} BG \tag{11-3}
\]

where:
\[ p_{\text{col}} = \text{collapse pressure of liner hanger body} \]
\[
B = \left[ \frac{D d_{\text{body}}}{N_{\text{coneseg}}} \right] \times N_{\text{cpads}},
\]

where:
\[ d_{\text{body}} = \text{OD of body} \]
\[ N_{\text{coneseg}} = \text{total cone segments cut} \]
\[ N_{\text{cpads}} = \text{number of cone pads} \]
\[
G = \frac{\tan \alpha + \mu}{1 - \mu \tan \alpha}.
\]

Equation 11-2 provides the maximum hanging load that may be imposed on the supporting casing, assuming:
- the casing in place is not supported by cement or formation behind the pipe
- the supporting casing is new pipe that has not been weakened or greatly enlarged by drillpipe wear or pressure
- the correct friction factor is used.

Equation 11-3 gives the maximum hanging load that the hanger will support before the hanger body fails. Both calculations are performed, and the lesser of the two results is used to determine how much liner weight can be carried by the hanger and in the casing in which it is placed.

For many years, thousands of pull tests and field runs were performed, and these have shown that liner capacities are greater than those calculated by the formulas above. But translating either the pull tests or the calculated results to actual downhole conditions is another matter. Factors that have a direct bearing on the downhole liner capabilities are the following:
- Is the supporting casing in new or near-new condition?
- Is the supporting casing backed up by hard, good-quality cement?
- What is the actual ID (not nominal ID) of the casing in which it is set?
- What is the actual friction factor for that specific hanger in a particular well?

The first three questions cannot always be answered at the time the hanger is designed. Possibly, a reasonable estimate of actual existing conditions could be found before running the liner, but even this is doubtful. For all of the above reasons, the formulas discussed above are used when recommending a hanger load of a slip-and-cone type hanger design. Historically, most liner hangers designed using these calculations do not fail or allow the liner to move down the hole.

11-6.4.4.2 Liner hanger types
Liner hangers can be classified into two types:
- Mechanically set liner hanger
- Hydraulically set liner hanger.

Both types are available in a variety of designs. The type of setting mechanism required, or the amount of weight the liner hanger will encounter at its setting depth, determines the number of slips and cones it will need. Simple designs have a single row of slips and cones; other designs may have two or more rows of slips and cones to increase the carrying capability.

Both designs use the same wedge technology, which consists of the following components (Fig. 11-108).

**Slip.** This device is wedged between the cone on the liner hanger and the casing in which it is set. This slip has hardened sharp teeth on the outside that bite into the casing, preventing the liner from sliding downhole.

**Cone.** A ramp on the liner hanger body that the slip moves along until the slips bite into the casing wall.

**Mechanically set cone-and-slip liner hanger**

The mechanically set liner hanger (Figs. 11-107, 11-109, and 11-110) was the first type designed. It was introduced in the 1920s. The setting mechanism consists of two items: the jay cage and the bow springs. The jay cage is a sleeve attached to the hanger body. The sleeve can be released from the body by means of pipe manipulation. This allows the slips to move from the run-in position to the set position. The bow springs are made from hardened steel that will not wear out easily while running in the hole. Their main function is to hold backup
friction on the jay cage to facilitate the liner-hanger setting operation.

The same design principles are still used today. The mechanically set liner hanger is available in a variety of designs with the same features and benefits.

- There is excellent bypass area, because the hanger does not require a setting piston that may restrict the bypass and decrease the overall pressure rating.
- The hangers can be set and activated with pipe manipulation. Depending on the model and type of setting tool, setting is performed by picking up the drillstring and the liner in tension at the required setting depth and either rotating the string to the left or the right and slacking off.
- The hangers match the liner pipe strength in almost all liner sizes.
- The hangers do not require setting pressure to activate. This saves rig time because no ball or plug is pumped down to temporarily close off the liner system. Using this type of liner hanger will also prevent overpressuring the formation.
- There is a continuous mandrel without any setting ports and seals.
- The hangers can be set and unset multiple times on a single trip.
- The hangers are not sensitive to temperatures or harsh environments that may compromise the seals.
- Erratic circulation pressures do not interfere with the hanger setting mechanism.

Hydraulically set, slip, and cone liner hanger

The hydraulically set liner hanger (Figs. 11-111 and 11-112) was introduced in the early 1940s. It was designed to allow running a liner in highly deviated or crooked holes or through casing windows, in which the
activation mechanisms of mechanically set hangers can become stuck. Hydraulically activated liner hangers have a smoother outside profile.

Two types of hydraulic-set hangers are available—one in which the hydraulic setting mechanism is built into the hanger and one with the hydraulics built into the running tool.

The cone and slip design (Fig. 11-108) is identical to the design of mechanically set hangers. Thus, both types have the same load-carrying capabilities. The only difference is that the hydraulically set hanger is activated at the required setting depth by applying a predetermined differential pressure at the liner hanger (Fig. 11-113).

The hydraulically set liner hanger is available in a variety of designs with the following features and benefits.

- Hydraulically set liner hangers do not require pipe manipulation to activate the hanger, as some mechanically set liner hangers do. Pipe manipulation may be difficult in heavy long liners and highly deviated wells or on conventional rotary drilling rigs without a topdrive system. Hydraulically set liner hangers do not require left-hand rotation of the drillstring, which could potentially back off a connection during the setting process.
- The smoother profile on the outside aids the running of liner systems into and past existing liner tops.
- The hydraulically activated independent setting mechanism does not rely on friction between the bow springs and the casing, as mechanically set liner hangers do. Certain drilling fluids decrease the friction between the bow springs and can prevent the setting of the hanger.
- The liner string can be rotated before setting, allowing the liner to more easily pass ledges and bridged-off areas in the well. This is virtually impossible with mechanically set hangers, because rotation of the pipe may activate the setting mechanism.
- The shear mechanism is normally preset and pretested for downhole conditions and reliability.

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Fig. 11-111. Single-cone hydraulic-set liner hanger (drawing courtesy of Baker Oil Tools).

Fig. 11-112. Multicone hydraulic-set liner hanger (drawing courtesy of Baker Oil Tools).
Rotating liner hangers that allow liner rotation during the cement job

Conventional hangers are normally set in the wellbore, and running tools are released before pumping the cement in place. Pipe manipulations during the cement displacement greatly increase the overall quality of the cementing job (Chapter 5).

The first rotating liner systems were introduced in the early 1960s. A mechanically set rotating liner hanger was designed with a special liner setting tool that would allow the liner hanger to be set and the liner setting tool assembly to be released from the liner. One could still rotate the liner string. The liner hanger was equipped with a full-circle floating cone at the top of the liner hanger. A conventional industry-standard ball bearing assembly was located above the cone and below the top connection.

Although this hanger improved rotational performance, it provided only small cross-sectional areas between the liner OD and casing ID, resulting in severe dynamic load constraints. These liner systems were run on a J-type setting tool and setting sleeve combination with inherent load and torque weaknesses. They could be run only on short, lightweight liners.

In the early 1980s, operators showed more interest in rotating liners without altering the conventional liner installations. New custom-designed bearings (Fig. 11-114) specifically for liner applications were introduced. In most cases, the new bearings did not increase the overall maximum OD of the conventional liner hanger. Newly designed liner setting tools for rotating liner hangers were more robust than the conventional running tools.

Rotating type hangers are designed for both the mechanically set (Fig. 11-115) and hydraulically set liners (Fig. 11-116), with the same setting mechanisms and operating and running guidelines as described earlier (Section 11-6.4.4.2). The running tools used with these types of rotating type liner hangers can be seen in Figs. 11-95B (mechanical running tool) and 11-96A (hydraulic running tool).

There are other aspects to consider when comparing rotating liners to conventional ones. First, rotating hangers use bearings and are rated for a particular load carrying capacity, depending on the design and size. The bearings must withstand the total weight of the liner while the hanger is set, plus the drillstring weight placed on the setting tool. As described in Section 11-6.4.2, the drillstring weight prevents the packoff assemblies from being lifted out of the top of the liner during the pumping operations.
stages. This total combined weight may exceed the load rating of a bearing when a cup seal system (Fig. 11-98) or PBR packoff system (Fig. 11-100) is used in large liner sizes. Such packoff systems typically are not used with liners that can be rotated during the cement job.

Second, torque is applied to the drillstring and liner string to rotate the liner. Therefore, both the drillstring and the liner-joint threads that attach the liner joints to their accessory equipment must be considered. Threads with low torque ratings and the nonshouldered connections used on conventional liners should not be used on a rotating liner, because this may prevent liner rotation during the job. Torque failure owing to excess torque can result in several negative consequences. Leaks may occur, and the liner ID could be reduced, preventing proper cleanup. In addition, it may be impossible to seal additional tools into the liner at a later stage of the well completion.

When running a rotating liner, one must be sure to use the proper centralizers. Not all centralizers used on conventional liners are suitable with rotating liners (Section 11-5.11).

Last but not least, when a rotating liner is planned, the drilling rig must be considered. The ability to rotate the liner and drillstring while maintaining control of the amount of weight that is placed on top of the liner during the job requires special surface equipment (Section 11-6.4.1). When working from a rig with a topdrive system, one should use the equipment shown in Fig. 11-93. When working off of a conventional rig without a topdrive, one should use the equipment shown in Fig. 11-92 and carefully maintain control of the liner weight.
**Liner hangers for all types of conditions**

Up to this point, only the conventional slip-and-cone liner hangers have been discussed. In the late 1980s, a hanger was introduced that does not require any welding, which allowed manufacturers to make liners cost-effective and comply with any corrosion resistant alloy (CRA) material an operator specified. The slip-and-cone design has been replaced by the slip-and-slip seat design, which has uniform casing contact, and allows the slips to match the contour of the casing in which the hanger is set. This even liner-load distribution greatly increased the load-carrying capabilities versus conventional liner hangers. Operators could also run extra-long liners in combination with the higher loads created by liner top packers with a high pressure rating. Some hanger sizes can hold 1.8 million lbm [816,470 kg] in combined loading, with little or no casing damage.

Because these hangers are supplied in a “kit form,” they can be made in various designs without changing many components and can sometimes be converted in the field without having to order completely new tools.

The standard hangers are available in mechanical (Fig. 11-117) and hydraulic (Fig. 11-118) versions, both with and without the bearing option.

The slips on these hangers are enclosed inside the slip seat and are particularly appropriate for liner systems that must be rotated while running in the hole to the desired setting depth. Some running tools (mainly hydraulically operated types) will allow this operation to occur during the installation. The slips on conventional hangers are completely open and are held in place with small screws; such hangers are not appropriate for operations that require rotating while running. Slips could break from the hanger while running in the hole, and the system could become stuck. Expensive fishing and milling operations would then be necessary.

Because these hangers can be assembled from a kit, they can be delivered with various special options for unique liner applications without having to design a completely new tool. These options include the following.

**Double grip.** Some liners are so short and light that it is difficult to detect if the setting tool assembly has

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**Fig. 11-117.** Mechanically set liner hangers (drawings courtesy of Baker Oil Tools).

**Fig. 11-118.** Hydraulically set liner hangers (drawings courtesy of Baker Oil Tools).
released from the liner. The double grip function allows the operator to pull tension into the liner after the hanger has been set and the setting tool has been released. Overpull (pull-up weight greater than that of the liner) indicates that the setting tool assembly is still attached to the liner. No overpull indicates the setting tool assembly is disconnected from the liner.

**Antileft-hand rotation feature.** The antileft-hand option is also available for short liners that are run with hydraulically operated tools and require some type of mechanical backoff. On conventional short and light liners with a bearing liner hanger, the liner may rotate on the bearing after the hanger has been set. Disconnecting the setting tool assembly from the liner may be impossible.

**Drill-down liner hangers**

Drill-down liner systems are often confused with wash-down liners, which require some rotation for short periods of time. Some well conditions require treating the liner like a conventional drilling string to run it to setting depth. In such cases a special drill-down liner hanger (Fig. 11-119) is run that is machined out of one piece of material. These hangers are only made in a hydraulically set version because of the rotational requirements before reaching setting depth. The conventional setting cylinder is replaced by a setting piston mechanism to increase the bypass area and prevent the cylinder from becoming stuck during run-in. Some of these liner hangers are designed with a liner top packer to make the system even smoother on the outside and shorter in length (Fig. 11-120).

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**Fig. 11-119.** Drill-down liner hanger (drawing courtesy of Baker Oil Tools).

**Fig. 11-120.** Liner hanger with liner top packer (drawing courtesy of Baker Oil Tools).
11-6.4.5 Shoe track assembly

The shoe track assembly (Fig. 11-91[5]) is run at the bottom of the liner. Its function is basically the same as a shoe track of a full casing or long string. It consists of a chamber between a number of backpressure valves. The assembly prevents contaminated cement from entering the openhole section at the end of a cement job. The backpressure valves have the same function as float valves in a full casing or long string. They prevent the cement slurry from U-tubing, or flowing back into the liner after the setting tool has been pulled out of the liner top. The liner shoe track assembly normally consists of three parts.

- **Shoe or guide at the bottom of the string.** As with conventional casing tools, the shoe or guide at the bottom of the string is called a float shoe (Section 11-5.2). The float shoe guides the liner through the openhole section to the bottom of the well or the desired setting depth. Side and bottom ports ensure reliable circulation at all times, even if the liner is set on bottom or is lying on the low side of a highly deviated wellbore. The float shoe is delivered with either one or two backpressure valves. It is made of easily drillable material for removal after the cement has set and before drilling the next hole section.

- **Upper valve system at the top of the shoe track.** On conventional casing strings, this valve is called a float collar (Section 11-5.2). It is normally placed one or two joints, and in some cases several joints, above the float shoe. The spacing between the float shoe and float collar depends on the liner size, expected contaminated cement after the cement job, and, in some cases, particular field or well cluster characteristics. The inner components of the float collar are made from the same drillable material as the float shoe.

- **Landing collar.** The landing collar is usually run one or two joints above the float collar. If the operator decides not to use a float collar, the landing collar can be installed above the shoe. Normally, this tool is only run with liners and not installed in a full-casing-string cementing operation.

   Landing collars catch displacement plugs and provide a secondary backup to the float valves in the float shoe and float collar. When the running tools are pulled out of the liner top, the landing collars prevent backflow or U-tubing of the cement. There are two types of landing collars. One (Fig. 11-121) provides a seat-and-latch assembly to latch the displacement plugs at the completion of cement displacement. Combined, they are designed to ensure rapid and complete drillout if needed for additional hole sections below the liner. The second type (Fig. 11-122) has one additional feature—an integral ball seat below the displacement plug seat. When activating hydraulic devices in the liner string, such as hydraulically set liner hangers (Section 11-6.4.4.2), ACPs, or cementing valves, the liner string must be temporarily plugged off by dropping a setting ball to the seat in the landing collar. This creates a closed chamber that allows the string to be pressurized. Pressurizing the drillstring and liner creates a differential pressure inside and outside the string. This pressure increase activates the hydraulically set devices in the string at various intervals. A further increase in pressure shears out the setting ball and seat in the landing collar, restoring full circulation through the shoe for cementing operations. When hydraulically operated devices are only run at the top of the liner string, the setting ball and seat may be placed closer to the liner top. In such cases, a standard landing collar without the ball seat is used.
Displacement plugs perform the same function as those in conventional long string casing cementing operations. Fluids such as drilling muds, completion fluids, spacers, washes, and cement slurries should be separated to prevent cross contamination as they are pumped through tubulars and up the annulus.

Conventional casing plugs are pumped directly from the surface because they pass through only one continuous pipe ID (Fig. 11-123). Liners are run on the drillstring to the setting depth and typically have a much larger ID than the drillstring above them; as a result, a single plug cannot be pumped from the surface. Therefore, the displacement is performed by two displacement plugs. One plug, known as the drillpipe dart (Fig. 11-124), is located in the surface cementing equipment or cementing manifold on the rig floor (Section 11-6.4.1). The plug is located between two inlets in the manifold and is kept in position by a retracting pin inside the plug-dropping head. The second plug is either attached to the bottom of the liner setting tool assembly, as described in Section 11-6.4.2, or is attached to the top of the liner hanger assembly. This second plug is called a liner wiper plug (Fig. 11-125). It has a port through the middle ID to allow fluid to be pumped through it (Fig. 11-123A).

After the cement has been pumped in the liner and the drillstring, the drillpipe dart is released from the surface cementing equipment by retracting the pin in the cementing head. The drillpipe dart is pumped as a separator behind the cement and in front of the displacement fluid (Fig. 11-123B).

When the drillpipe dart reaches the top of the liner, it latches into the liner wiper plug. This plugs the center hole (ID) of the liner wiper plug, and both plugs become a single divider between the cement and the displacement fluid (Fig. 11-123C).

Both plugs then travel down the liner to the landing collar in the shoe track (Section 1.4.5) and displace the cement into the annular space between the OD of the liner and the ID of the openhole section (Fig. 11-123D). A pump-pressure increase at the surface indicates that the plugs have landed and reached the landing collar.

The method described above only separates the end of the cement slurry and the beginning of the displacement fluid; thus, cement-slurry contamination at the front end is still possible. Some operators use cement displacement plugs before and after the cement slurry. This system is basically run with two drillpipe darts run from the surface and two liner wiper plugs run at the bottom of the liner setting tool assembly, described in Section 11-6.4.2. Both liner wiper plugs (Fig. 11-126) have ports through the middle to accept different sizes of drillpipe darts and are released accordingly. A special landing collar (Fig. 11-127) is required at the top of the shoe track to allow cement-slurry bypass after the first drillpipe dart and liner wiper plug have reached the landing collar.

This plug system is also used in special two-stage cementing operations in which the formation cannot withstand the hydrostatic pressure of the cement column in a single stage. In these applications, a cementing valve (Fig. 11-128) is placed in the liner string. This allows a short first-stage cement job to be performed. The cementing valve is then opened above the first stage of cement. After the first-stage cement has set, the second-stage cement slurry is displaced on top of the first stage, thus decreasing the total hydrostatic pressure.

Sometimes the liner sizes are so small that the ID through the liner is equal to or smaller than the ID of the drillstring on which the liner is run. In these cases, the plugs behave similarly to long-string plugs in that they can be dropped from the surface without having a liner wiper plug at the top of the liner or the bottom of the running string. The cement-slurry volume pumped through such liners is typically small. Any contamination of this small volume of cement may compromise wellbore integrity, and separating the cement from spacers and displacing fluids is especially important. The system
Fig. 11-123. Drillpipe dart and liner wiper plug displacement sequence (drawings courtesy of Baker Oil Tools).
consists of two drillpipe darts and a special slimhole landing collar (Fig. 11-129). The lead pumpdown plug or drillpipe dart is dropped from the surface in front of the cement slurry, and the second pumpdown is dropped at the tail of the cement slurry. The first plug separates the cement from the wellbore fluid, is pumped through the drillstring into the liner, and lands in the slimhole landing collar at the top of the shoe track near the bottom of the well. A pressure increase allows verification of the displacement volume. Increasing the pressure to a predetermined level will open the bypass ports in the slimhole landing collar above the pumpdown plug, allowing the cement slurry to enter the openhole section. Finally, the second pumpdown plug is dropped behind the cement slurry and lands on top of the slimhole landing collar insert, indicating the completion of the cement job.
11-6.6 Liner selection

For many years, the oil and gas industry has been searching for a method to reliably determine the correct liner equipment for a particular situation. There are as many variables that can influence liner equipment selection as there are to predict liner hanger capacity, as described earlier. Some of the variables that greatly influence the liner equipment selection are discussed below.

**Available equipment in a liner versus casing size.** Some liner models and designs are not available in all sizes. Alternatively, the annular space between the casing ID and the liner OD may be so small that even coupling-type liner joints do not fit. In these cases, some liner equipment designs are not feasible. In addition, wellhead restrictions at the top of the well can prevent certain designs from being run.

**Available equipment in the area within the expected installation date.** Although a wide variety of liner equipment is available around the world, the most suitable equipment may not be available at a particular location. In these cases, a compromise must be made, and the best possible alternative will have to be delivered to the rig site to meet the expected installation date.

**Circulation rates and temperature and pressure requirements.** In some cases, the liner equipment is installed in wells in which the expected temperatures are well beyond 500°F [260°C]. Such well conditions exceed the temperature ratings of most sealing materials, making it difficult to choose most conventional hydraulically operated tools. Pressure requirements at some liner setting depths are beyond the rating of conventional hydraulic setting cylinders. Also, the combination of high circulation rates, drilling-fluid densities, viscosity, and temperatures prevents some conventional liner top packers from being installed in the same trip as the liner and may require a second trip for installation (tieback packer).

**Well conditions and geometry.** Some operators prefer hydraulic equipment over mechanical equipment because of its ability to rotate in case the liner does not slide to the bottom on its own. However, in some wells, the top of the drilling fluid is at an unpredictable depth or the drilling-fluid density is not homogeneous. These situations make it difficult to determine the hydrostatic pressures of these fluid columns and operate hydraulically activated tools downhole.

**Drilling rig capabilities and available running string.** Some liner installations require special operations to be performed by the drilling rig. Some rigs do not have these capabilities and make the proper liner selections impossible. If coiled tubing, small-size drillpipe, or...
threaded tubing is used in large hole sections, insufficient weight may be available to set the liner top packers or allow rotation to activate mechanically set equipment.

These are just a few of the parameters that can influence liner equipment selection. Of course, the preferences of operators and drilling and completion engineers also enter into the equation. Some operators may want to use only mechanically set equipment, while others choose hydraulic equipment. Such preferences may be based upon previous experience. Last but not least, local regulations may prevent some tools from being selected or imported.

Despite all of the variables discussed above, liner selection flowcharts provide preliminary guidance concerning the proper liner equipment to use. An example is shown in Fig. 11-130.

![Fig. 11-130. Liner selection flow chart (courtesy of Baker Oil Tools).]
11-7 Remedial cementing tools

Remedial cementing tools are mechanical or hydraulic devices used downhole to assist in the placement of cement during plugback or squeeze cementing operations. They generally isolate areas of the casing from treating pressures and cement. Some are available in retrievable or drillable designs, each being suited for a particular set of well conditions. Remedial cementing tools are generally provided with service. Details of a specific tool’s operation or limitations should be obtained from the service company or manufacturer.

11-7.1 Cased hole squeeze packers

Squeeze packers are primarily used to isolate the upper portion of the casing and wellhead from cement and squeeze pressures and to improve control and placement of fluids during squeeze cementing operations. They are available in either drillable or retrievable types and differ considerably in appearance and operation. Retrievable squeeze packers may be set and released repeatedly; they are most useful in multiple setting operations, such as selective testing and cementing of multiple zones. Squeeze packers are run on tubing and are available in compression-set (Figs. 11-131A and 11-131B) or tension-set designs (Figs. 11-132A and 11-132B).

Compression-set packers are usually more versatile and are therefore preferable whenever sufficient tubing height is available. Generally 10,000 to 20,000 lbf [44.5 to 89.0 kN] is the minimum required compressive or tensile force to pack off the elements of either compression or tension packers. Most compression packers are set by slightly lifting the tool, rotating to the right (one-quarter turn at the tool), and setting down to apply the necessary force. This operation frees the lower slip assembly to slide over the lower cone and engage the casing wall. As the tubing is lowered, the elements are compressed until they are packed off against the casing. Compression packers are released by simply raising the tubing.

Tension packers are usually set at depths less than 4,000 ft [1,219 m] and are set by running the packer 20 ft [6 m] past the setting depth and then picking back up to setting depth. This procedure prevents buckling caused by running in the hole with the tubing in compression. Next, right-hand rotation (three quarters of a turn) is applied to the workstring at the tool. To ensure the tool is set, slack off (release the hanging weight at the wellhead) 10,000 lbf, or the weight of the string if 10,000 lbf is unattainable. After verification that the tool is set, the operator can pull 25,000 lbf [111 kN] at the tool to close the bypass and pack off the elements. The tool is now set and ready to perform its job. To unset the tension packer, the operator should slack off 10,000 lbf or the string weight. This will open the bypass and equalize the packing elements. Once equalized, the string weight is taken to neutral and the workstring is rotated three quarters of a turn. The packer is now unset and free to come out of the hole.
Retrievable squeeze packers usually include many design features to improve performance and versatility. Most compression packers use hydraulic hold-down slips to resist upward forces generated by the treating pressures below the packer. Some packers provide a bypass valve that may be opened or closed while in the set position. This feature provides more accurate control of slurry placement by allowing circulation without unset-
ting the packer. Also, the provision of a bypass area beneath the elements reduces swabbing and piston effects while running and allows reverse circulation of excess cement slurry without exerting excessive pressures. Packers with full-opening mandrels permit the use of through-tubing perforating guns, pressure recorders, or other wireline accessories.

Drillable squeeze packers, commonly referred to as cement retainers (Fig. 11-133), may be set on wireline or tubing. They are generally made of cast iron and are made compact to minimize drilling time. A sliding sleeve or poppet valve is provided to control slurry placement and preserve final squeeze conditions. Sliding sleeve valves are operated by raising and lowering the tubing. They prevent flow in either direction. Cement retainers are often used instead of retrievable packers to prevent backflow of cement when dehydration is not expected as well as to isolate the treated area from pressures because of the reversing of excess cement from the tubing. Cement retainers are also better suited to situations in which potential communication with upper perforations or casing problems that may lead to cementing a retrievable packer in the hole.

Cast-iron cement retainers are set using any of three methods. When accurate depth control is an issue, a wireline-set cement retainer (Figs. 11-133A and 11-133B) is deployed with an adapter to connect the cement retainer to the wireline setting tool. The cement retainer is lowered to the proper position and set by electrically firing a slow-burning charge in the setting tool. When the cement retainer is completely packed off, the setting tool shears free and is retrieved with the wireline. To cement through the retainer, a stinger is run on tubing, drillpipe, or coiled tubing and inserted into the cement retainer.

The second method of setting is on drillpipe or threaded tubing (Fig. 11-133C). Either tubing or drillpipe is used because of the need to rotate the tubing to set the cement retainer.

Third is the coiled tubing setting method (Fig. 11-133D). The cement retainer is connected to a tubing setting tool, and a valve is opened to allow the tubing to fill as the cement retainer is lowered. The valve is pushed open by lowering the tubing and closed by raising the tubing. Hydraulic pistons push out the top slips, allowing the retainer to be set by pulling up on the coiled tubing. The stinger is connected and run in the hole with tubing to perform the squeeze. Rotating the tubing to the right releases the upper slips and initiates packoff in some models. The tubing is then pulled to complete the packoff. When the proper setting tension is achieved, the setting tool shears free. The setting tension may range from 18,000 lbf [80 kN] for 4½-in. sizes to 48,000 lbf [214 kN] for 9½-in. sizes.
Fig. 11-133. Drillable cement retainers (drawings courtesy of Baker Oil Tools).
11-7.2 Cased hole bridge plugs

Bridge plugs are normally used to isolate the casing below the zone to be treated. When set, bridge plugs act as solid barriers to prevent flow and resist pressure from above or below. They are available in drillable and retrievable designs for wireline or tubing-set operations. Retrievable bridge plugs are often used in multiple zone applications, because they can be set and released as often as necessary. They may be run in tandem with retrievable packers for single-trip straddle operations.

However, tension packers are not recommended for tandem running operations with certain bridge plugs, because their combined operations may prevent freeing the tension packer, locking the entire assembly down-hole.

Retrievable bridge plugs are available in cup or packer configurations. Cup bridge plugs (Fig. 11-134D) are generally used in shallow, moderate pressure applications. They are simpler and more economical than packer models. However, the cups are in constant con-

![Fig. 11-134. Retrievable bridge plugs (drawings courtesy of Baker Oil Tools).](image-url)
tact with the casing while the bridge plug is being run, which causes wear and increases swabbing and piston effects. Cup bridge plugs may be run on tubing or a cable (sand line) and are released and retrieved with a retrieving sleeve. However, a special retrieving sleeve and procedure are required for sand line operations. When released, the bridge plugs are automatically set by applying pressure from above or below. Cup bridge plugs (Fig. 11-134D) may be used in tandem with a tension packer. Packing element bridge plugs (Figs. 11-134A, 11-134B, and 11-135C) use a packer element design that is more durable and well suited for deep, high-pressure applications. They have smaller external diameters that permit faster running and reduce swabbing and piston effects.

Retrievable bridge plugs are coupled to the tubing by a retrieving sleeve and are typically set by rotating to the right while lowering the tubing to apply force (generally at least 10,000 lbf [44 kN]). Some models feature a left-hand rotational set that requires no additional weight. These may be used in shallow applications or to permit removal of surface equipment. They are released from the tubing by pulling up slightly (1,000 lbf [4 kN]) while rotating to the left (one quarter turn at the tool). Retrievable bridge plugs are retrieved by lowering the retrieving sleeve while circulating to remove sand and debris from above the bridge plug. When solid contact is made, the tubing is raised to apply a slight upward force (2,000 to 3,000 lbf [9 to 13 kN]) while rotating to the right. Once free, the bridge plug may be retrieved or moved to another position. To prevent cement and perforation debris from interfering with the retrieval, sand should be placed on top of retrievable bridge plugs. Sand may also be used above drillable bridge plugs to reduce damaging shock waves caused by closely placed perforating guns.

Drillable bridge plugs are used to create a temporary or permanent plug for squeezing or plugback applications (Figs. 11-136A and 11-136B). They are often used to seal off nonproductive zones or wells to be abandoned. They are made of cast iron and are constructed similarly to cement retainers. The basic difference is that the mandrels are plugged and do not contain check valves. Drillable bridge plugs may be set on wireline, threaded tubing, drillpipe, and coiled tubing. Setting on wireline allows the establishment of zonal isolation without a rig; however, this cannot be done in high-angle wells.

The setting tools and procedures are often the same as those used for cement retainers. Some drillable bridge plugs are designed to allow pressures above and below the plug to equalize before drilling through the top slips. This feature is most important when gas or high pressures are expected below the tool.
11-7.3 Tubing testers and unloaders

Tubing testers (Fig. 11-137A) are downhole valves used to check the tubing for leaks. They are typically used during squeeze cementing operations, because of the potential problems that exist while pumping cement under moderate-to-high differential pressures. A leaking connection may permit local cement dehydration, creating false squeeze indications or completely plugging the tubing.

Tubing testers are typically equipped with a fully opening flapper mechanism. The full opening bore permits the use of through-tubing perforating guns or other wireline tools. Tubing testers are placed above a packer and are run in the open position to allow filling. They are typically closed by rotating the tubing (one-quarter turn at the tool) to the right and lifting. They are reopened by simply lowering the tubing. A simple ball-seat sub may also be used to test the tubing. However, the ball seat somewhat restricts the ID of the tubing, and the ball must be reverse circulated to the surface before pumping.

Tubing unloaders (Fig. 11-137B) or tubing bypass valves are placed in the tubing string to provide an alternate passage for circulating or spotting fluids. They are often used with packers that are not equipped with built-in bypass valves and therefore must be unset to permit circulation. Tubing unloaders are operated by raising or lowering the tubing. They are suitable for tension or compression packer operations.
11-7.4 Cementing using inflatable service tools

Inflatable service tools have been used in the oil and gas industry for more than 50 years to perform a variety of remedial workovers. Inflatable packers, bridge plugs, and cement retainers are used in open holes, cased holes, slotted liners, and gravel-pack screens, but they should be used only when conventional tools are not suitable. Inflatable packers employ a large rubber element that is inflated with a fluid to form a seal against the casing or open hole. They have a much smaller OD than conventional tools. These packers can be run through wellbore restrictions and inflated up to 250% of their run-in OD.

Inflatable tools are especially useful in open holes of uncertain size. Just like conventional packers and bridge plugs, inflatable service equipment can be set up in any array (i.e., retrievable packer, resettable packer, retrievable bridge plug, and cement retainer), allowing the same operations to be performed as with conventional equipment. Inflatable equipment is in neither compression nor tension. The pressure inside the inflatable element holds the equipment in place. Inflatable packers can be run on threaded pipe, drillpipe, coiled tubing, and wireline, making them just as adaptable as their conventional counterparts.

11-7.5 Inflatable service packers

Inflatable squeeze packers (Figs. 11-138A, 11-138B, and 11-138C) are used primarily to isolate the upper portion of the casing and wellhead from cement and squeeze pressures. They are also used to improve control and placement of fluids during squeeze cementing operations. Normally, inflatable squeeze packers are set and released only once, but they can be configured to allow multiple settings. The inflatable service packer is a retrievable device that may be run on drillpipe, threaded pipe, or coiled tubing. It is best suited for establishing zonal isolation in open hole or casing. Because of the inflatable elements’ large expansion capacities, the packer can be run through wellbore restrictions and set in the larger ID below. In such applications, the inflatable service packer or resettable service packer is run through a casing restriction and set above a production zone to protect the restriction above. The treatment fluid is spotted to the circulating valve (Fig. 11-139), the valve is closed, and the treatment fluid is injected into the formation below.
11-7.6 Circulating valve
The circulating valve was designed to open and close the tubing immediately above an inflatable packer and to permit reversing, equalizing, circulating, and spotting of acids, cement, or other fluids. This device is similar to the unloaders discussed earlier. The circulating valve is a simple lug and J-slot mechanism with a left-hand-turn opening sequence. Shear pins prevent premature opening while running in the hole (Fig. 11-139).

![Fig. 11-139. Circulating valve (drawing courtesy of Baker Oil Tools).](image)

11-7.7 Inflatable bridge plugs
Inflatable bridge plugs are primarily used to establish isolation between zones. They can be run on drillpipe, threaded pipe, coiled tubing, and wireline. Because of the inflatable elements’ large expansion capacities, the packer can be run through wellbore restrictions and set in the larger ID below. Inflatable bridge plugs (Fig. 11-140A) are run with an on-off connector (Fig. 11-140B). This allows the operator to activate and deactivate the inflatable bridge plug mechanically with pipe rotation. If the operator cannot use pipe rotation, a hydraulic release running tool (HRRT) (Fig. 11-140C) can be used. The HRRT is used to isolate a lower zone or for zonal abandonment. This device can be run on wireline, coiled tubing, threaded pipe, or drillpipe. A hydraulic disconnect is ideal for use with the wireline setting tool (Fig. 11-141) or coiled tubing if rotation is a problem. It is ideal for openhole abandonments and is simple to use. A variety of accessories can be used with these products to aid in setting, retrieving, circulating, spotting, and treating.

![Fig. 11-140. Inflatable bridge plug and on-off connectors (drawings courtesy of Baker Oil Tools).](image)
11-7.8 Through-tubing electric wireline setting tool

The through-tubing electric wireline setting tool (EWST) (Fig. 11-141) is an electric downhole pump powered from the surface by means of conventional wireline. The EWST uses fluid from either the wellbore or a reservoir carrying system to inflate and pressurize inflatable packing elements. The setting tool incorporates a magnetic casing collar locator to allow accurate depth control. The operation of the system is tracked at surface by monitoring the amperage draw of the tool on the power supply. When used with an inflatable packing element, fluid is drawn into the setting tool and filtered before entering the pump section. The pump section forces the fluid into the inflatable element, where it is trapped by a poppet-style check valve. At a predetermined pressure, the setting tool hydraulically disconnects from the inflated tool, allowing retrieval of the EWST and wireline to surface.

11-7.9 Inflatable cement retainer

Combining a flapper-valve assembly (Fig. 11-142A) with a permanent inflatable bridge (Fig. 11-142B) creates a cement retainer. Cement retainers are usually used to squeeze off unwanted production or gas channels between the open hole and casing. The bottom bull plug is removed and replaced with a shear-out ball seat. The lift sub on top is replaced with the valve assembly.

An inflatable cement retainer allows cement to be pumped into channels. Once the cement is in place, the hydrostatic pressure is relieved by pulling out of the retainer. Once out of the retainer, a valve closes and does not allow further squeezing.
11-7.10 Software for inflatable tools

Most tool manufacturers provide job-design software for operations involving inflatable products. An example is shown in Fig. 11-143.
11-8 Through-tubing inflatable products

In the early 1980s, coiled tubing began to play an important part in the workover industry. Many operators sought an efficient way to perform workovers without killing the well. Coiled tubing was the answer.

In the past, the only way to perform a kill-free workover operation was to use a snubbing unit. This technique was slow, required many safety precautions, and presented environmental risks in offshore locations.

Another obstacle of snubbing operations was that they had to be performed without pulling the production tubing and without pipe rotation. Many companies began developing tools that could be run through the production tubing and set in the casing below. This required a unique tool—one that could expand up to 300%, withstand elevated temperatures, and be as durable as possible. Through-tubing packers were born from this need, and today any job one can do on a conventional rig can be done using coiled tubing (Graves et al., 2004).

11-8.1 Through-tubing inflatable retrievable packer

The through-tubing inflatable retrievable packer (TTIRP) (Figs. 11-144A and 11-144B) provides a means of performing remedial and stimulation operations without removing the production tubing (Mackenzie and Plante, 1999). This versatile tool is typically conveyed into the wellbore with coiled tubing and allows the operator to selectively perform operations on zones within the wellbore. Typical applications for the retrievable packer are remedial cementing, acid stimulation, chemical water shutoffs, selective production testing, hydraulic fracturing and pressure testing operations.

Setting of the TTIRP is performed by placing a setting ball in the coiled tubing at surface and pumping it to the ball seat at the bottom of the coil. Once the ball is on seat, pressure is applied and the element is inflated to the tubing ID and held for 20 to 30 min. Once the maximum inflation pressure is reached, any additional pressure will shear the ball sub, resulting in a pressure drop. The pressure drop causes a poppet inside the element to close and maintain the pressure inside the element. Now the operations can be performed. When the job is complete and the operator is ready to pull equipment out of the hole, a larger ball is pumped to shear out an equalizing seat. With the packer equalized, the packer can be retrieved. A straight pull is all that is needed, and the release pins will shear and allow a slot in the mandrel to be pulled across the deflate ports. The packer is then deflated and pulled from the wellbore.

Pulling the TTIRP through the tubing end is not a problem because the element has been compressed to its run-in size. If the packer becomes stuck in the tailpipe, a hydraulic disconnect can be activated by dropping a larger ball to disconnect from the packer and allow the coiled tubing to be pulled from the well. The packer left behind has a fishing profile that is compatible with through-tubing fishing tools. Pressure inside the element is predetermined using a software application (Section 11-8.5) that plans the job and tells the operator how much fluid will be required.

Fig. 11-144. Through-tubing retrievable packers (drawings courtesy of Baker Oil Tools).
11-8.2 Through-tubing inflatable retrievable bridge plug
The through-tubing inflatable retrievable bridge plug (TTRBP) (Figs. 11-145A and 11-145B) is typically conveyed into the wellbore with coiled tubing or EWST (Fig. 11-141), allowing for all the inherent advantages of working over a well with the completion in place and not having to kill the well. Applications for the TTRBP are the same as those for any standard retrievable bridge plug. The TTRBP may be retrieved by means of threaded pipe, coiled tubing, or slickline, and equalized, released, and retrieved in a single run.

11-8.3 Through-tubing inflatable permanent bridge plug
The through-tubing permanent bridge plug (TTPBP) (Figs. 11-146A and 11-146B) is a nonretrievable inflatable bridge plug used to permanently plug the casing below the production tubing. Applications include: permanent water shutoff, permanent shutoff of a lower zone, and well abandonment. The TTPBP can be run on coiled tubing, threaded pipe, or wireline using an EWST (Fig. 11-141A).

Fig. 11-145. Through-tubing retrievable bridge plug (drawings courtesy of Baker Oil Tools).

Fig. 11-146. Through-tubing permanent bridge plug and completion (drawings courtesy of Baker Oil Tools).
11-8.4 Through-tubing inflatable permanent cement retainer
The through-tubing cement retainer (TTCR) (Figs. 11-147A and 11-147B) allows permanent isolation and cementation of a lower zone without pulling the production tubing and packer. The built-in retrievable spotting valve (Fig. 11-147B) provides a means of spotting cement to the top of the TTCR so that unwanted fluids are not pumped into the formation. Because the TTCR and spotting valve operations do not require rotation, the tool can be run on coiled tubing or threaded pipe. The TTCR houses opposing flapper valves, negating the chance of cement contamination after release of the running string from the retainer.

11-8.5 Through-tubing inflate design software
Job-design software is available for through-tubing inflate operations (Fig. 11-148). The program was developed to help in the information gathering, engineering, execution, and postjob reporting stages of an isolation planned with through-tubing inflate technology (Mackenzie and Patterson, 2004).

11-9 Acronym list
ACP/ECP Annular casing packers/external casing packers
API American Petroleum Institute
BWOC By weight of cement
CRA Corrosion resistant alloy
DNV Det Norske Veritas
EWST Electric wireline setting tool
HRRT Hydraulic release running tool
ID Inner diameter
LCM Lost circulation material
OD Outer diameter
PBR Polished-bore receptacle
PDC Polycrystalline diamond compact
TD Total depth
TTCR Through-tubing cement retainer
TTIRP Through-tubing inflatable retrievable packer
TTPBP Through-tubing permanent bridge plug
TTRBP Through-tubing inflatable retrievable bridge plug

11-10 Suggested reading
Fig. 11-148. Job-design software for through-tubing inflate operations (courtesy of Baker Oil Tools).
12-1 Introduction
The previous chapters have shown that there are many facets to a cementing operation. This chapter provides guidance on construction of a well-specific cementing program assessing the key elements of slurry selection and cement placement. The engineer must consider data from a variety of sources and optimize the parameters of the cementing operation according to the well conditions. This chapter describes in detail how to systematically analyze the data to align the design of the cementing operation with its operational and economic objectives.

12-2 Problem analysis
Every cementing operation has a set of specific objectives combining technical considerations (ranging from simple fill-up criteria to sophisticated isolation requirements) with project economics and local regulations. For the cementing operation to fulfill its objectives, the design engineer must first consider three basic types of well data.

- Depth and dimensional data
- Wellbore environment, including pressure regime and drilling fluid engineering
- Temperature regime

These data dictate the cement properties and the displacement regime for a given well. The annular configuration and the pore and fracture gradients play a large role in determining the flow regime, because they restrict the density and rheology of the fluids and consequently influence their pump rates.

Wellbore conditions also indicate whether special materials must be considered owing to the presence of gas, salt, or other influences. These factors, along with the pressure and temperature profiles, guide the selection of additives for controlling the slurry-flow properties and setting behavior.

All the data types listed above are related to the state of the well at the time of drilling. However, the objective of well cementing is to not only place cement correctly in the annulus after a section is drilled but also to provide zonal isolation between the respective zones for the expected life of the well. A fourth category of concern must therefore be added: One must carefully consider any parameter that may affect the integrity of the cement sheath and the quality of isolation during the well’s productive lifetime and after abandonment. This is particularly important in certain environments in which the cost of remedial intervention to repair a defective primary cementing job or restore zonal isolation may be very high.

12-2.1 Depth and dimensional data
The information that must be gathered when planning a primary cementing operation includes

- vertical depth
- measured depth
- angles and azimuths of deviation
- casing size and weight
- openhole size
- string type (e.g., full string, liner, tieback, and multistage).

Depth data are particularly important because they strongly influence the temperature, fluid volume, and hydrostatic and dynamic pressures. High-angle wells are particularly challenging and require strict control of mud displacement and slurry stability (Keller et al., 1983).

No well is exactly vertical unless directional drilling techniques are available. Figure 12-1 shows a three-dimensional (3D) survey of a conventional well that was considered vertical. Most boreholes twist and turn in various directions. Unless the exact hole trajectory is known, the relatively flexible casing string will not be adequately centralized and may touch or lie on the borehole wall at various locations.

Chapter 5 illustrates the dramatic adverse influence of eccentered pipe on mud-removal efficiency. Performing a detailed directional survey, or 3D survey, of the borehole (measured depth, deviation angle, and azimuth) over the entire interval provides sufficient knowledge of the well path to ensure proper centralization, mud removal, and zonal isolation. Drilling with bottomhole assemblies containing measurement while
drilling (MWD) or logging while drilling (LWD) tools is becoming more common. Thus, such information is often readily available.

When planning the centralization of a casing in a "vertical well" without 3D survey data available, the design engineer should always use a minimum deviation of a few degrees (usually 3°) to account for uncertainties in trajectory. Alternatively, some use randomization techniques to introduce variations in trajectory between two survey points.

In principle, the openhole size is dictated by the drill-bit size. Along with the casing size and type, the open-hole size should be selected according to the expected well conditions and completion configuration. In an actual well, the open hole is rarely "gauge" (i.e., perfectly round and cylindrical). Soft, unconsolidated zones or formations containing shales tend to be unstable. If the formation stresses and the mud density are not balanced, the formation can slough and break into fragments that can be difficult to remove from the wellbore.

Variable hole shape affects the required slurry volume and well control. It can also dramatically affect the displacement mechanics. Various wireline-caliper tools have been developed to measure hole size. Drawings and basic characteristics of each are summarized in Fig. 12-2 and Table 12-1. In general, calipers that record a greater number of independent measurements provide a better estimate of hole size and volume (Table 12-2).

The first calipers had two or three arms. If a true caliper log was not available, an estimated hole size could be derived from measurements recorded by a single-arm system used to convey logging tools. However, hole sizes calculated from such measurements were highly inaccurate if the well was deviated or if the size and shape of the hole were irregular.

Changes in hole size and shape often occur in one preferred direction, usually perpendicular to the minimum stress in the formation. Stress-induced shape changes can result in highly oval wellbores in which two- and three-arm calipers are inaccurate. A four-arm tool was introduced to measure these holes accurately (Fig. 12-3). Four-arm calipers, also called X-Y calipers, provide rough hole-shape measurements and more accurate hole-volume estimates than single-axis calipers. However, real-world boreholes are never truly round or truly elliptical. Thus, the X-Y caliper is often coupled with a pad-mounted tool, such as a dipmeter or one of the more modern imaging tools.

Hole size can also be measured ultrasonically. This technique is often used to measure casing corrosion because of its high resolution. The rotating sensor measures the transit time and computes the standoff 140 to 180 times per revolution. The use of such ultrasonic technology is limited by the attenuation of the wellbore fluid.

Fig. 12-1. 3D survey of a "vertical" well (from Maeso and Tribe 2001; reprinted with permission of SPE).
Table 12-2. Caliper Types and Hole Geometry

<table>
<thead>
<tr>
<th>Caliper Type</th>
<th>Round Hole</th>
<th>Oval Hole</th>
</tr>
</thead>
<tbody>
<tr>
<td>Two-pad single measurement</td>
<td>Correct volume</td>
<td>Wrong volume</td>
</tr>
<tr>
<td>Three-pad single measurement</td>
<td>Correct volume</td>
<td>Volume too small</td>
</tr>
<tr>
<td>Four-pad two-axis measurement</td>
<td>Correct volume</td>
<td>Volume OK</td>
</tr>
<tr>
<td>Six-pad independent measurement</td>
<td>Correct volume</td>
<td>Best determination</td>
</tr>
</tbody>
</table>

Fig. 12-2. Examples of single-, two-, and three-arm calipers.

Table 12-1. Characteristics of Different Calipers

<table>
<thead>
<tr>
<th>Tool Type</th>
<th>Number of Arms</th>
<th>Phasing of the Arms</th>
<th>Max. Diameter</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density</td>
<td>2</td>
<td>180°</td>
<td>22 in. [560 mm]</td>
<td>2 coupled arms: one reading</td>
</tr>
<tr>
<td>Sonic</td>
<td>3</td>
<td>120°</td>
<td>16 in. [406.4 mm]</td>
<td>3 coupled arms: one reading</td>
</tr>
<tr>
<td>Borehole geometry</td>
<td>4</td>
<td>90°</td>
<td>40 in. [1,016 mm] with extension arms; 30 in. [762 mm] standard</td>
<td>4 arms coupled 2 by 2: two-axis caliper</td>
</tr>
<tr>
<td>Various imaging tools</td>
<td>4</td>
<td>90°</td>
<td>17.5 to 21 in. [444.5 to 533.3 mm]</td>
<td>4 arms coupled 2 by 2: two-axis caliper</td>
</tr>
<tr>
<td>Environmental measurement</td>
<td>6</td>
<td>60°</td>
<td>40 in. [1,016 mm] with extension arms; 30 in. [762 mm] standard</td>
<td>6 independent readings</td>
</tr>
<tr>
<td>sonde</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ultrasonic imaging tool</td>
<td>Ultrasonic</td>
<td>Rotating sensor</td>
<td>12 in. [317.5 mm]</td>
<td>140 to 180 readings per revolution; limited by mud attenuation</td>
</tr>
</tbody>
</table>
In recent years, a sonde using six independent arms has dramatically improved the determination of the precise borehole shape. Such calipers provide extensive drilling and petrophysical information. An ovality algorithm helps determine the shape of the borehole for stress-analysis studies, an important element for predicting wellbore stability.

In many areas, however, wireline caliper tools are not run, particularly in the large surface-hole sections. It is therefore a common practice to specify a given percentage of excess cement slurry to ensure the required annular fill-up. This widely accepted field practice is not without drawbacks (Section 12-4), because this “excess” is largely based on local offset analysis, including geology, mud, and drilling practices.

In the absence of any hole-size measurement, the “fluid caliper” (Stringer and Barrett, 1990) offers an alternative method to estimate the volume of the open hole. A fluid caliper uses a small volume (pill) of tracer fluid, containing an easily identifiable material that is detected when it returns to the surface. A drawback of this method is that it requires at least one full circulation cycle. Additionally, it does not account for the dispersion of the tracer in the entire mud volume and assumes that all of the drilling fluid is mobile and being circulated.

With the advent of MWD and LWD tools, openhole size can be derived from acoustic measurements (Orban et al., 1991; Minear et al., 1996; Maranuk, 1997), nuclear measurements (Paske et al., 1992), or resistivity measurements in conductive drilling fluids. These measurements provide more information about borehole stability when made during both drilling and pipe-tripping operations.

Combinations of LWD measurements are particularly useful for detecting borehole-stability and trajectory problems. Such early diagnostic information allows the

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**Fig. 12-3.** Four-arm calipers and ultrasonic tool.

**Fig. 12-4.** The six-arm caliper tool and log.
mud and drilling engineers to propose remedies and take immediate action before the problem worsens, resulting in a better-quality openhole section. For example, the combination of ultrasonic-caliper and density measurements produces borehole-shape images that can be transmitted in real time via telemetry (Maeso and Tribe, 2001). Figure 12-5 shows the LWD tool, and Fig. 12-6 shows an example of the information that allows the driller to make sound decisions concerning the drilling process.

The integration of the ultrasonic caliper information and data derived from neutron and density measurements produces a robust and accurate description of the wellbore that can be used by the driller and the petrophysicist alike (Ortenzi et al., 2002). Given that each of the caliper estimates derived from LWD measurements is valid only within a certain operating range and environment, the integrated caliper uses a simple weighting logic based on environmental indicators.

Labat et al. (2002) describe the development of an azimuthal 3D LWD caliper from 16 sector density measurements. This application is useful for drillers, who can optimize drilling parameters and reduce wellbore stability problems such as ovalization, washouts, and spiraling. In addition, cementers not only have a more exact estimate of the hole volume from the 16 radial measurements, but also information on the hole shape and trajectory. This information helps optimize centralizer placement and drilling-fluid removal, critical elements of a good cementing operation.

Before selecting a particular casing weight, grade, or metallurgy, engineers consider the mechanical stresses to which the casing will be exposed and take into account the possible corrosive nature of the formation fluids. The well-design engineer can use stress-analysis software to select casing that will withstand the production operation conditions. However, the cementing engineer must also account for the possible high differential pressures across the pipe wall, which may cause the casing to collapse or burst. This can occur when there are large fluid-density differences between the cement slurry and displacement fluid or when there are large final-displacement or casing-test pressures.

Longitudinal forces must also be considered. The dead weight of the casing will cause it to stretch. Buoyancy will cause compression. For larger casing sizes, one must take measures to ensure that buoyancy will not cause the casing to be pumped uphole during the cementing operation. The calculations necessary to ensure this does not happen are described in Appendix C.

In many primary cementing operations, other factors prevail. Logistics, availability, and standardization will often dictate the use of a standard pipe weight and grade when the well conditions do not impose a much stricter choice.
12-2.2 Wellbore environment

The specific problems of the openhole interval to be cased require careful evaluation. The presence of pay zones, overpressured formations, low fracture gradients, gas, or massive salt zones presents particular challenges. Careful job design is required to overcome these wellbore-related problems.

It is important to know the pressure regime along the entire openhole section. Pore pressures are important for well control, and such information may be obtained from logs. If logging facilities are not available on location, the mud weight provides a fair indication of the maximum pore pressure in any given interval. Even when the mud weight has been chosen for other considerations, such as wellbore stability, it provides an upper bound of the pore pressures in the well.

If a kick occurs during the course of drilling, it provides important information about pore pressure. At the other extreme, the risk of fracturing the formation must be carefully assessed, and a mean fracture-pressure gradient is normally provided for each openhole interval. These values are normally based on either leakoff testing, which is performed upon drilling out the shoe of the previous casing string, or a formation integrity test at any particular depth of interest.

Other sources of formation-pressure information include the following.

- Data from formation tests, particularly fluid sampling and pressure readings
- Data from stimulation or squeeze cementing treatments in offset wells
- LWD and annular pressure-while-drilling measurements [these tools provide an accurate downhole equivalent circulating density (ECD), especially important when drilling high-pressure, high-temperature (HPHT) wells with highly compressible oil-base mud (OBM)]

Pay zones merit special attention. It is important, for example, to avoid unnecessary damage from excessive fluid leakoff from the cement slurry. The slurry filtrate is ordinarily not a concern because it does not penetrate the formation as deeply as the drilling fluid. In most cases in which the well is perforated before production, the charges penetrate the damaged zone. Cement grains are too large to penetrate any porous rock matrix. Nevertheless, care should be exercised when cementing fractured and/or depleted reservoirs to avoid opening fractures and losing the whole cement slurry deep into the reservoir.

Productive formations must be effectively isolated from each other and from nonproducing intervals or aquifers to ensure maximum long-term productivity from the well (Chapter 1). If the formations are known to contain gas, special cement slurries (along with other precautions) may be required to ensure that gas does not migrate through the column of setting cement (Chapter 9). It is important for the engineer to not only consider the pay zones, but also any zones that contain fluids (gas or brine) that may flow through the hydrating cement column.

The physical and chemical properties of the mud influence cement-job design (Sauer, 1987). Cement slurries are usually incompatible with drilling fluids. Mixing these fluids leads to rheological difficulties and poor mud removal. To prevent commingling, chemical washes, spacers, or other flush fluids are usually pumped between the drilling fluid and cement slurry (Chapter 5). Such fluids are designed to be chemically compatible with both the drilling fluid and the cement slurry. OBM invariably require the use of solvents or surfactants in the spacers or washes to improve compatibility, to remove the oil film from the casing and formation surfaces, and to leave the surfaces water-wet (Carter and Evans, 1964). Each solvent/surfactant system is tailored to the particular OBM, particularly its base oil.

Complete displacement of the drilling fluid over the interval of interest is a primary objective of any cementing operation. To facilitate removal, the viscosity of the drilling fluid should be as low as feasible. Whenever possible, the anticipated downhole properties of the drilling fluid should be used, because these may be significantly different from those measured during the regular mud checks at surface conditions. This is particularly true for OBM, for which pressure and temperature play a significant role in its properties.

Debris and cuttings should be cleaned out of the borehole by circulating at an adequate rate for an appropriate amount of time. Numerical simulators are useful to verify that preflushes do not bypass the mud and do not allow the mud and cement to commingle (Section 12-4). In cases in which 100% mud removal cannot be assured, a cement slurry may be modified to minimize the adverse effects of commingling (Rae and Brown, 1988). Data on compatibility are obtained by performing laboratory tests in accordance with procedures defined by the International Organization for Standardization (ISO) and the American Petroleum Institute (API) (Appendix B), operators, and service companies.
12-2.3 Temperature regime

The bottomhole circulating temperature (BHCT) and the bottomhole static temperature (BHST) must both be considered, in addition to the temperature differential between the bottom and top of the cement column. The first of these, BHCT, is the temperature that the cement slurry will theoretically encounter as it is placed in the well. It is the temperature used for HPHT thickening-time tests of a proposed cement formulation. The BHCT dictates the selection of specific retarders and other additives, depending upon their efficacy under such conditions.

The BHCT is calculated using sets of temperature schedules last published in ISO 10426-1:2000 or the regional American National Standards Institute (ANSI)/API 10A/ISO 10426-1:2001 version (April 2002). Work performed by the API Task Group on Cementing Temperature Schedules between 1984 and 1991 was published in 1999, and resulted in an update of the temperature schedules used in Recommended Practice for Testing Well Cements, API Recommended Practice (RP) 10B (1999). However, the ISO/API standards do not account for unusual well conditions such as the cold temperatures found in deepwater wells (Calvert and Griffin, 1998) or the hot temperatures found in some deviated wells (Wooley et al., 1984). They further assume that the surface-formation temperature is a constant standard of 80°F [26.7°C]. A method called the API Equivalent Wellbore has been recently proposed to correct these shortcomings (Kutasov, 2002). This method recalculates a pseudolength of wellbore (the equivalent wellbore), and uses a special equation (the Kutasov-Targhi equation) to calculate the BHCT. The equivalent wellbore method works best when used for deeper wells in which the length of the section being investigated is negligible with respect to that of the entire well. The method does not take into account well geometry, flow geometry, or the fluids pumped (rheology, rate, time, and flow regime for heat exchange).

Some operators prefer to design cement systems using temperatures actually measured in the well during circulation. One method to obtain such temperatures is to circulate small temperature probes in the mud and retrieve them as they exit the well (Jones, 1986). However, the poor recovery rate of the probes has led to abandonment of this technique. Temperature subs (Cloud, 1992) have been used by Honore et al. (1993) in conjunction with temperature recorders and by Ward et al. (2001) to record temperatures and temperature profiles in wells. However, using simulators requires that measurements be correlated with the flow geometry (drillpipe and hole/casing size) and flow history (mud rheology, injection rate, and injection periods).

As part of MWD or LWD technologies, different temperatures can be measured during the drilling and circulating process. The tool’s temperature probe measures the temperature inside the tool to allow necessary corrections to the other measurements. Therefore, only dedicated probes that measure the annular-fluid temperature should be used. It is important to note that this measurement is not a direct indication of the temperatures that will be experienced during the cementing operation. The flow contact areas, flow rate, and flow regime may be significantly different during the cement job. Furthermore, additional heat is generated during the drilling process.

As for the temperature subs, the main problem with LWD/MWD temperatures is that they are obtained from different geometries and with different flow rates. Unless these conditions can be simulated to calibrate the temperature measurements, these temperatures should not be used as the slurry test temperature.

Computer simulators that model the physics of heat transfer under dynamic conditions are now widely used (Guillot et al., 1993). These methods consider all of the well parameters important for heat transfer, including annular geometry (flow and contact area), fluid rheology, flow rate, and injection temperature. Therefore, they can predict temperatures at various points in a well and are especially valuable when cementing deepwater, deviated, or horizontal wells. The temperature simulators have been validated against field data in land and shallow-water offshore wells (Davies et al., 1994; Merlo et al., 1994); temperature simulation for deepwater wells (Romero and Touboul, 1998) was validated in 2001 (Ward et al., 2001). There is a variety of simulators that consider various degrees of complexity. The cementing team must agree on the circulation rate and duration required before cementing, because these two parameters critically affect the bottomhole cementing circulating temperature.

As an example, Fig. 12-7 shows the temperature profile in the casing and the annulus of a long horizontal well (measured depth [MD] = 27,900 ft [8,500 m], true vertical depth = 6,900 ft [2,100 m], and BHST = 185°F [85°C]). The measurements were taken after one complete cycle of mud circulation, after which cement was placed. The profile in this example is essentially flat over a large portion of the open hole, suggesting that the rheology of the fluids in the annulus will not change significantly during placement. On the other hand, the temperature history curve shows that the cementing circulating temperature is 167°F [72°C]. This temperature is significantly higher than that predicted by the corresponding API schedules (127°F [53°C]). Such a discrepancy could lead to significant differences in
cement-slurry behavior. If one chose a retarder concentration assuming a circulating temperature of 127°F [53°C], the actual thickening time in the well could be much shorter than desired and serious consequences could result, including loss of the well.

The BHST is the undisturbed temperature at the bottom of the wellbore. BHST is important for predicting the rate of compressive strength development and the long-term stability of a given cement system. It is usually calculated from the mean geothermal gradient in the area of interest, but it may be estimated from logging measurements. Although the ISO/API standards stipulate that compressive strength be measured at BHST, computer simulators can predict the rate at which the well temperature will rise from the BHCT to the BHST. For critical jobs, following such schedules may be preferable.

Figure 12-8 shows the temperature recovery at the bottom of a 2,625-ft [800-m] openhole section in a deepwater well at 8,200 ft [2,500 m] water depth. The BHST, predicted by the geothermal gradient, is 119°F [48°C]. The cement slurry was injected through drillpipe as part of a stab-in cementing operation without a riser. After cement placement (429 min in Fig. 12-8), the temperature at the bottom of the well was very low, close to the seabed temperature of 39°F [4°C]. Then the temperature slowly rose and returned to the BHST. The simulation shows that the temperature would reach 119°F [48°C] after 1 day. Such a slow temperature recovery could dramatically affect the cement-slurry setting time and the development of compressive strength. Using the normal BHST for strength development tests would lead to misleading results. Temperature simulators are thus used to derive realistic temperature schedules for performing laboratory tests that most closely simulate the actual conditions encountered by the cement slurries.

The temperature differential between the top and bottom of the cement can also be extremely important when embarking upon a cementing design. A cement system that has been retarded for adequate placement time at the BHCT may remain liquid or have poor strength development when circulated back to a shallower depth in the well. A useful guideline is to ensure that the static temperature at the top of the cement (TOC) exceeds the BHCT. Sabins et al. (1981) devised similar guidelines based on an experimental study of a number of cement formulations. When it is not possible
to meet these criteria, compressive strength tests should be performed that simulate the conditions at the TOC. If satisfactory compressive strength development cannot be achieved, it may be necessary to execute the job in more than one stage. Such guidelines provide a simple means of calculating a suitable depth for the location of the stage collar.

12-3 Slurry selection

A number of considerations come into play during the selection of a final slurry design for a specific well application.

12-3.1 Slurry density

In many cases, the selection of slurry densities is dictated by factors other than simple pore and fracture pressures. In the past, cement systems were often mixed at high densities for rapid compressive-strength development. However, economics may dictate the use of low-density extended or “filler” cements, which provide a higher slurry volume per sack of cement. However, the mechanical properties of the set cements may be inferior. The following drive slurry density:

- fracture gradient
- pore pressure
- cement composition (API class, commercial lightweight, proprietary blends)
- project economics
- well objectives.

12-3.2 Compressive strength and mechanical properties

Today, compressive strength is not as dependent upon slurry density. Strong cements can be designed at very low densities by controlling the particle sizes of the slurry ingredients (Chapter 7) (Baret *et al*., 1996; Moulin *et al*., 1997). Also, as discussed in Chapter 8, the practical importance of compressive strength has diminished (Thiercelin *et al*., 1997; Thiercelin *et al*., 1998; Di Lullo and Rae, 2000). Other mechanical properties such as Young’s modulus and Poisson’s ratio, previously ignored in the context of well cementing, are now increasingly recognized as important performance parameters.

However, the industry’s understanding of these parameters in the context of well construction is still in its infancy. These criteria address the flexibility of a cement system and its ability to withstand temperature, pressure, and tectonic fluctuations during the lifetime of a well (Baumgarte *et al*., 1999; Bosma *et al*., 1999; Le Roy-Delage *et al*., 2000; Ravi *et al*., 2002).

![Fig. 12-8. Temperature recovery in a deep offshore well.](image-url)
Nevertheless, industry and government regulatory bodies have issued guidelines and specifications for compressive strengths of cements used for certain applications. To learn the appropriate rules for the area in which you are working, contact the appropriate regulatory agency. Many of these regulations deal specifically with shallower regions, where concerns center on the satisfactory isolation of freshwater supplies. However, guidelines do exist for preferred strengths before drilling out (500 psi [3.5 MPa]) and perforating (2,000 psi [14 MPa]). It is therefore important to select a design that can meet these criteria. Compressive strength can also become a critical consideration when cementing across intervals such as mobile salts or pay zones that will require subsequent stimulation (Goodwin and Phipps, 1984; Rae and Brown, 1988). In some areas (e.g., deepwater wells with low formation temperatures) the rate of strength development is often more important than the ultimate strength.

12-3.3 Well temperature

Well temperature is a key consideration in the slurry-selection process. If the temperature at any location in the well exceeds about 230°F [110°C] at any time during the well’s lifetime, Portland cement systems must be modified to maintain adequate cement-sheath stability (Chapter 10). The addition of silica flour is the most common technique. Alternatively, one can select cement systems that are specifically designed for use in thermal wells (Brothers et al., 2001; Barlet-Gouédard et al., 2003). At the other extreme, cements used in arctic or other low-temperature cementing applications are specially formulated to generate a low heat of hydration, thereby minimizing the melting of permafrost (Smith, 1987) (Chapter 7).

12-3.4 Cement additives

Fluid-loss additives are generally incorporated in slurries that traverse pay intervals or in situations in which the annular gap is small. These materials reduce the rate at which the aqueous phase of a cement slurry leaks into the formation. Loss of water from a cement slurry can seriously affect its performance, particularly its viscosity during placement and the ability of the slurry column to transmit pressure after placement. It can also damage producing intervals (Suman and Ellis, 1977; Bannister, 1985), but this is generally considered a minor problem.

Fluid-loss additives should be selected with care, because most of them have secondary effects. For example, many fluid-loss additives are viscosifiers, so a dispersant may be needed to preserve slurry mixability and pumpability. Some form of cement-particle dispersion or deflocculation is always necessary for optimal fluid-loss-additive performance. In addition, fluid-loss additives may have secondary retarding effects. Certain other additives, notably some of the sugar-base retarders, can adversely affect the performance of a fluid-loss additive. Such considerations are discussed in detail in Chapter 3.

Even in the absence of fluid-loss additives, dispersants may be required for slurry mixability and to reduce friction pressures. Dispersants are particularly valuable in situations in which annular clearances are small and high friction pressures may pose some risk to weaker formations. When using dispersants, it is important to pay close attention to other aspects of slurry performance. Dispersants can act in synergy with cement retarders, resulting in a longer thickening time. Adding excessive amounts of dispersants can result in slurry instability, leading to high levels of free water and sedimentation. In some cases, antsettling additives may be required to counteract this effect. Stiles and Baret (1993) discussed models and a solution to sedimentation and free water observed in cement slurries. They found that the best model to describe particle settling in a flocculated cement slurry is based on the consolidation of the solids. However, the sedimentation of well-dispersed slurries is not well understood.

Cement retarders are the largest group of additives. Retarder selection depends upon the BHCT, the type (or even brand) of cement, and the exact slurry composition. The reader is referred to Chapter 3 for a complete discussion.

12-3.5 Cement-slurry design

Slurry design is an iterative process. The “first-guess” formulation, which is expected to meet the required performance criteria, is initially based upon experience. Local and regional databases and “expert systems” (Kelly et al., 1992) complement this local experience. Knowledge-based systems also facilitate and standardize the slurry-design process.

However, the variability of cements demands that actual laboratory testing be performed to verify the predicted results and refine the design. Although this might seem burdensome, experienced engineers and laboratory personnel can dramatically reduce the number of tests required to arrive at the optimal formulation for a given set of well conditions. Testing the final design with actual field samples is essential to prevent problems arising from material variability and contamination.
12-4 Placement mechanics

Good mud removal is the single most important requirement for a successful primary cement job. This subject has been reviewed extensively by Haut and Crook (1979), Smith (1982), and Sauer (1987) and is discussed fully in Chapter 5.

12-4.1 Spacers and chemical washes

Chemical compatibility between fluids pumped in succession is equally critical to mud displacement. As discussed earlier, cement slurries are usually incompatible with drilling fluids, causing gelation at the mud/cement interface and reducing the displacement efficiency. To prevent commingling, chemical-wash or spacer fluids are usually pumped between the mud and cement. Careful selection of these fluids is mandatory (Chapter 5). Numerical placement simulators are crucial tools to help determine the best solution. In some situations a chemical wash is appropriate. In other situations, a weighted spacer fluid is necessary to maintain hydrostatic overbalance across active formations throughout the job.

Spacers are normally pumped at densities between those of the mud and cement, because buoyancy forces have been shown to favorably influence the mud-removal process. Brice and Holmes (1963) first identified the importance of contact time (the time that the spacer is in contact with a given location in the annulus) to mud removal when using the turbulent-flow displacement process. Their original recommendation of a minimum 10-min contact time for fluids in turbulent flow remained an industry standard for many years. However, this is no longer necessarily considered valid.

Today there are numerical simulators that account for all of the wellbore and fluid parameters. The simulators ensure that two incompatible fluids will not mix during placement in the annulus and that the pumping time will be sufficient to remove the film of mud at the formation wall. As discussed in Chapter 5, these complex numerical simulators allow one to assess the impact of eccentricity on the efficiency of the planned displacement strategy.

The spacer composition depends upon the type of mud, the required flow regime (laminar or turbulent), the formations that are contacted, and the nature of the cement slurry. For example, freshwater-base spacers are used to remove freshwater-base muds, while salt-tolerant spacers may be required for salt-saturated muds. OBM is typically removed with spacers containing surfactants, organic solvents, or both. Special surfactants may be necessary when low-toxicity paraffinic-base muds are employed.

In addition to chemical compatibility, fluid dynamics play an important role in mud removal. Work by Frigaard et al. (2001) allows the design engineer to set targets for the required rheological behavior of the various fluids in the wellbore. Such information can be combined with a neural network-based expert system that recommends the optimal spacer composition (Théron et al., 2002). In all cases, compatibility testing between the various fluids should be performed to prevent unforeseen interactions that might undermine spacer performance (Appendix B).

While precautions should be taken to formulate fluids to efficiently displace the drilling fluid in the annulus, it is strongly recommended to use multiple wiper plugs to keep these washes and spacers from intermixing with each other or with the preceding mud, which would affect their properties and certainly their efficiency.

12-4.2 Casing centralization

The pipe eccentering problem was effectively addressed by Couturier et al. (1990) and Bittleston and Guillot (1991). Their work led to the development of modeling tools to optimize mud removal. These tools eventually evolved into a two-dimensional (2D) numerical placement simulator that allows precise visualization and quantification of the fluid-displacement process as each fluid moves up and around the annulus. Deviation, eccentering, and caliper measurements are taken into account to calculate the fluid properties in each cell of the simulation grid. Simulators help identify any tendency for channels or films to be left on the pipe and formation walls.

Owing to borehole irregularities, the casing is never in the center of the open hole. Fluids will naturally flow more readily on the wider side of the annulus. Thus, any mud-displacement strategy is seriously compromised unless there is adequate casing centralization. Maintaining an API casing standoff above 67% was an early guideline (Chapter 5). The real purpose of this guideline was to verify that centralizers conformed to minimum specifications. It was never intended as a cement job design target; indeed, channeling occurs at 67% standoff. Therefore, it is important to achieve the highest possible standoff to facilitate the displacement process.

Centralizer friction, casing rigidity, and borehole geometry may limit the number of centralizers that can be installed. To optimize centralizer placement, computer models (Juvkam-Wold and Wu, 1992) calculate the position and the standoff of the casing string at each point in the wellbore, accounting for well trajectory and size. A 3D survey and at least a four-arm caliper are recommended to determine the proper placement of centralizers in difficult or critical wells.
In situations in which the available data are limited to the directional survey, the engineer must obtain a best estimate of the washed-out zones. However, new tools are emerging that allow real-time transmission of drilling data from the rig to an engineering center. The cementing design engineer can then use simulators to calibrate hole size, trajectory, and volume for every newly drilled section (Queirós et al., 2003).

Centralizer calculations must determine the standoff not only at the centralizer itself, but at locations between centralizers. Casing can bend and sag between centralizers, resulting in dramatically lower standoffs. This problem increases with well deviation. The example in Fig. 12-9 shows that for a nearly vertical well (3° deviation at 6,562 ft [2,000 m]), the standard distribution of 1 centralizer per 3 joints gives an excellent standoff of 90–95% at the centralizer all along the interval. This requires 51 centralizers if the entire section is to be centralized. However, the standoff between centralizers would be as low as 43% near the shoe, compromising mud removal and jeopardizing the objective of achieving a good leakoff test at the shoe for drilling the next interval. The standoff is also as low as 30% in the small washed-out section between 1,100 and 1,200 m, making isolation difficult in this zone and in the interval above it.

Computer simulators can optimize the centralizer distribution for a given required standoff. In the same near-vertical well, achieving 75% standoff over the entire interval would require increasing the number of centralizers to 70 from 51 (Fig. 12-10); however, the centralizers would be distributed in a more effective way. Such an increase is a minimal expense compared to the cost of the operation and the risk of not achieving the required zonal isolation. There are various types of centralizers available, and their characteristics are discussed in Chapter 11.

12-5 Well control

Each well offers an “envelope,” or range, of acceptable pressures that must be respected to design and execute a successful cement job. The limiting pressure boundaries are normally the openhole pore-pressure and the fracture-pressure profiles; however, it is also important to consider the burst and collapse pressures of the tubulars.

Unless sufficient computing power is available, it is impractical for the engineer to examine the pressures at each point in the well throughout the entire treatment. For this reason, a good approach is to perform a worst-

![Fig. 12-9. Standoff in a near-vertical well with 51 centralizers (1 per 3 joints).]
case scenario analysis, which allows the engineer to quickly evaluate a particular design. This involves the identification of key problem areas in a given well, which are typically the zone of highest pore-pressure gradient and the zone of lowest fracture-pressure gradient. However, sections of the well in which the annular configuration changes should also be carefully examined, because the contributions of friction and hydrostatic pressures can be highly variable.

Normally, the weak zones in a well will encounter the highest pressure just before the completion of the job (i.e., seconds before the top plug “bumps”). At this point, the longest column of high-density fluid will be in the annulus, and friction will be at its highest level (ignoring any pump-rate reduction in anticipation of bumping the plug). This can be considered the worst-case scenario for zone breakdown. However, it is much more difficult to propagate a fracture with cement than it is with OBM. Therefore, the ability to circulate mud at the required rate is sufficient to raise confidence levels.

When performing an ECD simulation, the entire wellbore geometry, including restrictions around the liner hanger, must be considered.

Conversely, from a well-control standpoint, the worst situation occurs when the fluid of lowest density (typically a chemical wash) passes by an active zone. Depending upon the annular configuration or openhole diameter, the zone in question may not be that of highest pore pressure. For example, a large washed-out section can reduce the impact of a low-density fluid on the net hydrostatic pressure below it, while a tight interval can have the opposite effect.

In the event that the hole is gauge and no single zone exhibits an abnormally high pore pressure, a good guideline is to assume that the shallowest active zone poses the greatest risk to well control. Worst-case calculations should focus on this zone. One may ignore frictional components that may be present when the low-density fluid passes the zone (i.e., only hydrostatic pressure should be considered). This ensures that, even in the event of a shutdown, the well will remain secure in the absence of friction pressure. However, in such situations, the fluids may generally continue to flow owing to U-tubing (Section 12-6). Engineers should make U-tube assessments available to wellssite operations personnel, because U-tube events are often misinterpreted in terms of losses or gains, causing unnecessary changes in the proposed pumping schedule.

In the job-design process, friction pressures are most significant when small annuli are involved and must be calculated carefully. On the other hand, in large annuli, friction is usually negligible. Instead, a safe estimated value (50 to 100 psi [0.35 to 0.7 MPa] for the entire well) can be ascribed to friction pressure.

Pumping excess cement to ensure adequate annular fill is a common practice, particularly when the borehole size and annular volume are uncertain. Negative consequences may occur unless one considers the possible
effects of overfill. If the borehole is closer to gauge than expected, the excess cement may be circulated to a point higher than originally intended. If weak zones are present, the resulting elevated hydrostatic pressure may induce losses, compromising the results or endangering the well.

A similar and no less dangerous situation can arise if large volumes of low-density washes or spacers are pumped and the hole is more in-gauge than thought. If such fluids reach an unexpected height in the annulus, the resulting loss of hydrostatic pressure may compromise well control. Thus, having an accurate caliper log of the openhole section is not only useful for computing the required slurry volume, but is also necessary from a well control standpoint.

### 12-6 U-tubing

Pumping dense fluids such as cement slurries down a casing string can result in a phenomenon known as free-fall or U-tubing (Arnold, 1982; Beirute, 1984). The fluids inside the casing and in the annulus will naturally tend to achieve a hydrostatic-pressure equilibrium. During the course of the cement job, some interesting effects may be observed (for example, mixing of heavy and light fluids that are not separated by a wiper plug).

The density of cement slurries is usually higher than those of the drilling fluid, chemical wash, or spacer. When the cement slurry is introduced inside the casing, a hydrostatic pressure imbalance is created between the inside of the casing and the annulus. As a result, the cement slurry has a tendency to free-fall and draws a vacuum inside the upper part of the casing.

In many cementing operations, the pump rate into the casing is insufficient to keep the casing full during the early part of the job. This results in a net flow or efflux of fluid from the well. The rate of efflux may be much greater than the inward flow. Eventually, as hydrostatic pressure equilibrium is approached, the outward flow falls below the inward flow and the casing gradually refills. At some point, the outward flow may reach zero and the fluid column in the annulus may become stationary. Such events are easily misinterpreted as partial or complete loss of circulation. Finally, when the casing is again full of fluid, the inward and outward flow will be equal. However, these values may not remain so for the remainder of the job. If a low-density wash is present, it may cause an annular-pressure reduction as it flows past the casing shoe. This will in turn cause a second period of free-fall, accompanied by another surge of high returns. The beginning and end of U-tubing events can easily be detected by measuring the surface pressure during the cement job. Similarly, when U-tubing is finished, calculation of the wellhead pressure until the plug bumps indicates how quickly the heavier cement column is rising in the annulus.

Considering the importance of annular fluid velocities and pressures to the safe and successful execution of a cement job, it is clear that U-tubing must be considered in any job design. Algorithms exist that permit fairly accurate simulations of these phenomena (Beirute, 1984; Wahlmeier and Lam, 1985). These algorithms have been validated against carefully measured field parameters during cementing operations (Kelessidis et al., 1994).

The numerical manipulation needed to accurately simulate the physics of well displacement is considerable. Fortunately, computers with sufficient power to handle the algorithms at practical speeds are readily available today.

### 12-7 Example of job design procedure

The following example illustrates how the basic job-design concepts discussed above can be combined with the power of computer simulators to provide a realistic and technically suitable well program.

Whether computers are used or not, the process of designing a cement job complies with the following scheme:

- clearly defining the objectives
- collecting the data (offset and planned wells)
- identifying the different options
- assessing the risk of each
- making the final selection and decision.

#### 12-7.1 Well conditions and cement job considerations

A summary of the well data is presented in Table 12-3 and illustrated in Fig. 12-11.

The plan is to cement a 47-lbm/ft [69.9-kg/m], 9¾-in. [244 mm] intermediate casing at a depth of 6,486 ft [1,977 m]. The well is almost vertical, having a maximum deviation of 3° at the shoe. The open hole is reasonably in gauge, with most of the section diameter ranging from 12.2 to 13 in. [310 to 330 mm]. A few small, washed-out sections across the Aptian and Barremian formations extend the 15-in. open hole to about 18 in. [to 458 mm from 381 mm].

The Albian formation is a powerful aquifer that must be carefully isolated. However, weak formations below prevent the use of normal-density cements. Loss zones and salt sections exist above and below the Albian. A good cement bond across the casing shoe is required as
Table 12-3. Configurational Data for the 9\(\frac{5}{8}\)-in. Section of the Example Well

<table>
<thead>
<tr>
<th>MD (m)</th>
<th>Fracture Gradient (kg/m²)</th>
<th>Pore (kg/m³)</th>
<th>Equivalent Diameter (in.)</th>
<th>Formation Name</th>
<th>Typical Lithology</th>
</tr>
</thead>
<tbody>
<tr>
<td>399</td>
<td>—</td>
<td>—</td>
<td>12.519</td>
<td>13(\frac{5}{8})-in. casing</td>
<td>Previous casing shoe</td>
</tr>
<tr>
<td>402</td>
<td>1,558</td>
<td>1,020</td>
<td>15.297</td>
<td>Senonian salt</td>
<td>Evaporite</td>
</tr>
<tr>
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<td>1,020</td>
<td>12.287</td>
<td>Senonian salt</td>
<td>Evaporite</td>
</tr>
<tr>
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<td>1,558</td>
<td>1,020</td>
<td>12.287</td>
<td>Turonian Limestone</td>
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<tr>
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<td>1,020</td>
<td>12.287</td>
<td>Cenomanian Evaporite</td>
<td>Evaporite</td>
</tr>
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<td>737</td>
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<td>1,020</td>
<td>12.977</td>
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</tr>
<tr>
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<td>12.179</td>
<td>Albian Sandstone</td>
<td>Sandstone</td>
</tr>
<tr>
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<td>Sandstone</td>
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<tr>
<td>955</td>
<td>1,498</td>
<td>1,020</td>
<td>12.208</td>
<td>Aptian Sandstone</td>
<td>Sandstone</td>
</tr>
<tr>
<td>968</td>
<td>1,498</td>
<td>1,020</td>
<td>12.208</td>
<td>Barremian Sandstone</td>
<td>Sandstone</td>
</tr>
<tr>
<td>982</td>
<td>1,498</td>
<td>1,020</td>
<td>14.315</td>
<td>Barremian Sandstone</td>
<td>Sandstone</td>
</tr>
<tr>
<td>1,042</td>
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<td>1,020</td>
<td>12.208</td>
<td>Barremian Sandstone</td>
<td>Sandstone</td>
</tr>
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<td>1,066</td>
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<td>1,020</td>
<td>12.767</td>
<td>Barremian Sandstone</td>
<td>Sandstone</td>
</tr>
<tr>
<td>1,078</td>
<td>1,498</td>
<td>1,020</td>
<td>15.623</td>
<td>Barremian Sandstone</td>
<td>Sandstone</td>
</tr>
<tr>
<td>1,139</td>
<td>1,498</td>
<td>1,020</td>
<td>12.480</td>
<td>Barremian Sandstone</td>
<td>Sandstone</td>
</tr>
<tr>
<td>1,165</td>
<td>1,498</td>
<td>1,020</td>
<td>18.264</td>
<td>Barremian Sandstone</td>
<td>Sandstone</td>
</tr>
<tr>
<td>1,183</td>
<td>1,498</td>
<td>1,020</td>
<td>13.097</td>
<td>Barremian Sandstone</td>
<td>Sandstone</td>
</tr>
<tr>
<td>1,203</td>
<td>1,558</td>
<td>1,020</td>
<td>12.199</td>
<td>Barremian Sandstone</td>
<td>Sandstone</td>
</tr>
<tr>
<td>1,367</td>
<td>1,558</td>
<td>1,020</td>
<td>12.199</td>
<td>Neocomian Sandstone</td>
<td>Sandstone</td>
</tr>
<tr>
<td>1,380</td>
<td>1,558</td>
<td>1,020</td>
<td>13.143</td>
<td>Neocomian Sandstone</td>
<td>Sandstone</td>
</tr>
<tr>
<td>1,485</td>
<td>1,558</td>
<td>1,020</td>
<td>12.207</td>
<td>Neocomian Sandstone</td>
<td>Sandstone</td>
</tr>
<tr>
<td>1,695</td>
<td>1,558</td>
<td>1,020</td>
<td>12.207</td>
<td>Dogger anhydrite</td>
<td>Evaporite</td>
</tr>
<tr>
<td>1,850</td>
<td>1,558</td>
<td>1,020</td>
<td>12.207</td>
<td>Dogger shale</td>
<td>Shale</td>
</tr>
<tr>
<td>1,977</td>
<td>1,558</td>
<td>1,020</td>
<td>12.207</td>
<td>Dogger anhydrite</td>
<td>Evaporite</td>
</tr>
</tbody>
</table>
the mud weight is raised from 9.8-lbm/gal \([1,174-\text{kg/m}^3]\) to 17.1 lbm/gal \([2,050 \text{ kg/m}^3]\) for drilling the lower 8\(\frac{1}{8}\)-in. hole section. Common practice would dictate installing a stage collar just below the Albian. The 9 5\(\frac{1}{8}\)-in. casing section would be cemented using a two-stage technique, allowing the placement of a strong 15.9-lbm/gal \([1,905-\text{kg/m}^3]\) slurry across the second stage (Albian).

Placement difficulties and lost circulation below the Albian formation would normally require two-stage cementing, increasing rig time. Remedial operations may also be required. A better solution would be to perform a single-stage cement job, employing a high-performance, lightweight lead slurry based on engineered-particle-size blends (Chapter 7). A short, normal-density tail slurry would provide high strength at the shoe.

The lead slurry must be brought to surface. To avoid losses during and after pumping, the density of the lead slurry will be 11.5 lbm/gal \([1,380 \text{ kg/m}^3]\). The density of the tail slurry will be 15.9 lbm/gal \([1,905 \text{ kg/m}^3]\). Because salt formations are present all along the open hole, both the lead and tail slurries are mixed with 18\% salt water.

The static temperature at shoe is 176°F \([80^\circ\text{C}]\), corresponding to a geothermal gradient of 1.5°F/100 ft \([2.7^\circ\text{C}/100 \text{ m}]\). The calculated BHCT (from API tables) is 123°F \([50^\circ\text{C}]\). Circulating the well at 6.3 bbl/min \([1,000 \text{ L/min}]\) for 3 hr lowers the cementing circulating temperature to 118°F \([48^\circ\text{C}]\). Although this temperature is not very different from the API BHCT, it has not yet reached the pseudosteady state (Fig. 12-12). Therefore, any change in circulation time and rate will significantly influence the resulting BHCT.

The temperature profile after this 3-hr circulating period is fairly flat, around 122°F \([50^\circ\text{C}]\), with the temperature at the Albian formation being at or near the geothermal temperature (Fig. 12-13). The temperature near the surface will still be close to 104°F \([40^\circ\text{C}]\). Thus, compressive-strength development across the Albian formation or at the surface would not be jeopardized.

The mud in the hole is a saltwater-base polymer system with a density of 9.8 lbm/gal \([1,174 \text{ kg/m}^3]\), adequate to cover the equivalent mud-weight pore pressure of the Albian formation (9.6 lbm/gal \([1,150 \text{ kg/m}^3]\)). The rheological properties of the drilling fluid are reportedly good, with a plastic viscosity of 29 cp \([29 \text{ MPa-s}]\) and a Bingham yield of 11 lbf/100 ft\(^2\) \([5.3 \text{ Pa}]\), although the Herschel-Bulkley rheological model represents a better fit and is used for the computer simulations.

![Fig. 12-11. Well and formation data in job design example.](image)
Fig. 12-12. Temperature versus time at shoe. Depth is 1,973 m.

Fig. 12-13. Temperature profile after 3 hr of mud injection.
12-7.2 Slurry formulation
Both the lead and tail slurries require the incorporation of fluid-loss additives to maintain the designed slurry properties and avoid bridging across the permeable zones of this long interval. Dispersants will also be required for optimal fluid-loss control and because the friction pressures generated by the viscous slurries could pose a risk to weak zones. Additionally, the dispersant will facilitate the mixing of the lead slurry, which is designed with a very low water-to-solid ratio.

The duration of the job is likely to be 4 to 5 hr. Adding a 50% safety margin, the minimum thickening time of the lead slurry should be 6 to 8 hr, and less for the tail slurry (5 to 6 hr). A retarder will then be added to achieve adequate placement time.

The design criteria for each slurry will then be the following:
- **Lead slurry (11.5 lbm/gal [1,380 kg/m³])**
  + Special lightweight blend
  + dispersant
  + fluid-loss additive
  + salt (18% by weight of water)
  + retarder (if necessary) for thickening time of 7–8 hr
- **Tail slurry (15.9 lbm/gal [1,905 kg/m³])**
  + API Class G cement
  + fluid-loss additive to achieve API-estimated fluid loss rate of 80–100 mL/30 min
  + dispersant
  + antisettling viscosifier
  + salt (18% by weight of water)
  + retarder (if necessary) for thickening time of 5–6 hr

12-7.3 Mud removal strategy and spacer formulation
The cement slurries will not be pumped in turbulent flow, because of hole size and the presence of weak zones. This, and the risk of mud contamination, suggests the use of spacers or a combination of spacers and chemical washes to achieve good mud removal. The spacer density would be between that of the mud and the lead cement.

Simulators calculate the optimal rheology for the spacer to efficiently displace the drilling fluid in the hole at the given pipe standoff and with the planned range of pump rates (and their corresponding shear rates in the eccentric annulus), as shown in Fig. 12-14.

A neural-network expert system translates the required rheology for this cementing operation into a compatible combination of products to achieve the required performance under downhole conditions. This considerably reduces the amount of laboratory testing required to fine-tune the spacer composition. Finally, the mud removal criteria are verified for each fluid interface along and around the entire annulus as shown in Fig. 12-15.

To further improve the cementing operation, some chemical wash will be pumped ahead of the spacer to thin the drilling fluid and facilitate its removal. Owing to pore-pressure requirements and the need for a saline fluid, the density of the chemical wash is 9.6 lbm/gal [1,150 kg/m³]. It is important to perform tests to verify that the spacer and wash are compatible with the drilling fluid.

12-7.4 Job design
As discussed previously, adequate casing centralization is required for efficient drilling-fluid displacement and proper cement-slurry placement throughout the interval, from shoe to surface. Laboratory testing is performed to design slurry and spacer formulations that meet the required performance specifications. Such pilot testing also provides data concerning the rheological properties of the slurries, spacers, and mud at both surface and downhole conditions. These data (Table 12-4 and Table 12-5) are then used in the final job design.
The fluid volumes, density, rheology, and annular cement fill (along with information about the position of other fluids in the annulus at the end of the job) planned for this cementing operation are shown in Table 12-6. A graphical representation of the pressure margins (hydrostatic pressure only at this stage) with such a fluid column is shown in Fig. 12-16.

Table 12-4. Lead Slurry Properties

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>API/ISO fluid loss rate</td>
<td>24 mL/30 min</td>
</tr>
<tr>
<td>Free water</td>
<td>0 mL</td>
</tr>
<tr>
<td>Rheology at 100°F [37.8°C]</td>
<td>Herschel-Bulkley model</td>
</tr>
<tr>
<td>Consistency index</td>
<td>0.00396 lbf-s/ft² [0.189 Pa-s]</td>
</tr>
<tr>
<td>Power-law index</td>
<td>0.314</td>
</tr>
<tr>
<td>Yield point</td>
<td>16.3 lb/100 ft² [7.8 Pa]</td>
</tr>
<tr>
<td>10-min gel strength</td>
<td>42 lb/100 ft² [21 Pa]</td>
</tr>
<tr>
<td>Thickening time</td>
<td>8 hr, 5 min</td>
</tr>
<tr>
<td>24-hr compressive strength</td>
<td>3,320 psi [22.9 MPa]</td>
</tr>
</tbody>
</table>

Table 12-5. General Fluid Data

<table>
<thead>
<tr>
<th>Fluid Sequence</th>
<th>Volume (m³)</th>
<th>Annular Length (m)</th>
<th>Top (m)</th>
<th>Density (kg/m³)</th>
<th>Consistency Index (Pa-s²)</th>
<th>Power-Law Index</th>
<th>Yield Point Value (Pa)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chemical wash</td>
<td>3.2</td>
<td>0.0</td>
<td>–</td>
<td>1,150</td>
<td>0.005</td>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td>Spacer</td>
<td>14.3</td>
<td>0.0</td>
<td>–</td>
<td>1,320</td>
<td>2.490</td>
<td>0.300</td>
<td>1.69</td>
</tr>
<tr>
<td>Lead slurry</td>
<td>62.3</td>
<td>1,789</td>
<td>0</td>
<td>1,378</td>
<td>0.189</td>
<td>0.914</td>
<td>7.79</td>
</tr>
<tr>
<td>Tail slurry</td>
<td>6.4</td>
<td>185</td>
<td>1,789</td>
<td>1,900</td>
<td>0.396</td>
<td>0.694</td>
<td>7.08</td>
</tr>
<tr>
<td>Mud</td>
<td>73.3</td>
<td>–</td>
<td>0</td>
<td>1,174</td>
<td>0.151</td>
<td>0.747</td>
<td>3.48</td>
</tr>
</tbody>
</table>
Table 12-6. Job Schedule of Example Well

<table>
<thead>
<tr>
<th>Name</th>
<th>Flow Rate (L/min)</th>
<th>Volume (m³)</th>
<th>Stage Time (min)</th>
<th>Elapsed Time (min)</th>
<th>Cumulative Volume (m³)</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Start job</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Prejob safety meeting. Check data monitoring and recording equipment. Pressure-test lines.</td>
</tr>
<tr>
<td>Chemical wash</td>
<td>477</td>
<td>3.2</td>
<td>6.6</td>
<td>6.6</td>
<td>3.2</td>
<td>Pump chemical wash.</td>
</tr>
<tr>
<td>Spacer</td>
<td>954</td>
<td>14.3</td>
<td>15.0</td>
<td>21.6</td>
<td>14.3</td>
<td>Pump spacer.</td>
</tr>
<tr>
<td>Pause</td>
<td>0</td>
<td>0</td>
<td>5.0</td>
<td>26.6</td>
<td>0</td>
<td>Drop bottom plug.</td>
</tr>
<tr>
<td>Lead slurry</td>
<td>635</td>
<td>62.3</td>
<td>98.2</td>
<td>124.8</td>
<td>62.3</td>
<td>Mix and pump lead slurry.</td>
</tr>
<tr>
<td>Tail slurry</td>
<td>795</td>
<td>6.4</td>
<td>8.0</td>
<td>132.8</td>
<td>6.4</td>
<td>Mix and pump tail slurry.</td>
</tr>
<tr>
<td>Pause</td>
<td>0</td>
<td>0</td>
<td>5.0</td>
<td>137.8</td>
<td>0</td>
<td>Drop top plug.</td>
</tr>
<tr>
<td>Mud</td>
<td>954</td>
<td>47.7</td>
<td>50.0</td>
<td>187.8</td>
<td>47.7</td>
<td>Displace with mud.</td>
</tr>
<tr>
<td>Mud</td>
<td>636</td>
<td>11.1</td>
<td>17.5</td>
<td>205.3</td>
<td>58.8</td>
<td>Slow down rate in stages.</td>
</tr>
<tr>
<td>Mud</td>
<td>477</td>
<td>7.9</td>
<td>16.6</td>
<td>221.9</td>
<td>66.7</td>
<td>Slow down toward end displacement.</td>
</tr>
<tr>
<td>Mud</td>
<td>318</td>
<td>6.6</td>
<td>20.7</td>
<td>242.6</td>
<td>73.3</td>
<td>Slow down further—bump plug.</td>
</tr>
</tbody>
</table>

Fig. 12-16. Downhole pressure-density plot.
A simulation of the actual operation, including shutdowns, rate changes, U-tubing, etc., is shown in Fig. 12-17 and Fig. 12-18. Figure 12-17 illustrates the fact that flow rates in and out of the well are not equivalent during a large part of the job. Sudden increases or decreases in rate, resulting from fluids of varying density moving from the casing into the annulus, can be predicted ahead of time. Knowledge of the magnitude of these fluctuations, and the times at which they are expected, can help allay fears that well control is threatened or that serious losses have occurred.

Figure 12-19 provides data similar to those given by Fig. 12-16. In this case, dynamic frictional components are considered, as are all worst-case scenarios throughout the duration of the entire pumping operation. This graph reveals everything the engineer needs to know about well control. The minimum pressure safety margins are displayed in Table 12-7 for each of the parameters.

Once it has been verified that the planned conditions for the cement job will not create well-control problems, the final mud-removal parameters are verified with the
help of a 2D numerical simulator to visualize all the aspects of the mud-displacement process. For example, it is important to verify that one fluid does not bypass or fall through another, and that in the end the cement slurry is in direct contact with the drilling fluid.

Output from the simulator can be an animation of the entire process or a picture at any given time. Figure 12-20 displays the situation in the annulus 2 hr and 34 min after the beginning of the operation (refer to the pump schedule). It is essential to verify that, throughout the entire simulation, mud conditioning, pipe centralization, preflush, and slurry densities, rheology, and pump rates have been correctly chosen. This will ensure that the interfaces between fluids remain as flat as possible and the cement is never in contact with the mud.

**Fig. 12-19.** Well control.

**Table 12-7. Minimum Safety Pressure Checks in Dynamic Conditions**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Min. Absolute Pressure (MPa (psi))</th>
<th>Found at Depth (m)</th>
<th>Min. Relative Pressure (%)</th>
<th>Found at Depth (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture gradient</td>
<td>0.25 [36]</td>
<td>750</td>
<td>2.1</td>
<td>1,078</td>
</tr>
<tr>
<td>Pore pressure</td>
<td>0.15 [22]</td>
<td>750</td>
<td>1.7</td>
<td>759</td>
</tr>
<tr>
<td>Collapse rating</td>
<td>18.3 [2,650]</td>
<td>1,945</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Burst rating</td>
<td>40.5 [5,874]</td>
<td>0</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Fig. 12-20.** Snapshot of the annulus at 2 hr 34 min.
At the end of the simulated operation, the situation in the annulus in terms of cement coverage and expected isolation should be compatible with the objectives of the operation (Fig. 12-21). If the results are incompatible, the job parameters must be further optimized.

Cement may also become contaminated in the course of shipment, and should be sampled at the wellsite. Typical contaminants found in cement include bentonite (gel), barite, and silica. All can have a negative impact on slurry performance. To ensure that the materials at the wellsite perform properly, both the service company and the operating company should implement strict quality-control procedures. Additive drums, sacked materials, and silos bearing cement blends should be clearly marked to avoid mistakes.

Special instructions or procedures that are important to the success of the job must be communicated to the wellsite. It is imperative that personnel from the operating company and service company understand and agree on the exact details of the job. Recommendations to reciprocate or rotate pipe, install a given number of centralizers per joint, or pump at certain rates for specific periods of time are made with good reason, and every effort should be made to follow these instructions at the wellsite.

The use of computer-based data acquisition systems at the wellsite allows accurate monitoring of the operation. On-the-job recordings of pump rate, surface pressure, and fluid density can be plotted and compared with the original design simulations. This helps to ensure that jobs are executed as designed and also to identify anomalous well conditions in the course of the operation. Ultimately, such information can be used to help “close the loop” between design and execution, permitting the engineer to modify future designs to achieve optimal results. Before evaluating the cementing operation with a sonic or ultrasonic log (Chapter 15), the playback of data recorded during the cement job helps the engineer identify unforeseen problems that might have occurred (Smith et al., 1987; Beirute, 1987; Piot and Loizzo, 1998).

12-9 Conclusions

Designing a cement job is an iterative and collaborative process that starts long before the cementing operation. Ideally, the collaboration between the operating company and the service company begins at the well planning stage and continues throughout the drilling stage. As drilling progresses, the well data are continuously updated, and the cementing options continuously evolve. Then a final decision is made, specifying a cost-effective solution that is compatible with the job objectives.

This process encompasses the following steps (each may be repeated several times):

- determining and refining objectives
- planning for health, safety, and environmental issues
determining
- well geometries
- deviation
- static temperature gradient
- temperatures

studying problems in offset wells

selecting appropriate equipment and materials

finalizing job procedure options

finalizing slurry design options

selecting mud displacement strategy

selecting
- spacers
- cement systems
- procedures

finalizing the program.

Common sense is the engineer’s greatest asset in cement-job design. Considerable time can be saved by quickly distinguishing the relevant well characteristics from those that are not.

The engineering team must recognize any factors that may affect the final quality of the cement job. Otherwise, the final objectives of the cementing operation are less likely to be achieved.

Delivering a smooth wellbore with a smooth trajectory and a stable nongelling drilling fluid creates ideal cementing conditions. The farther the well conditions deviate from the ideal situation, the more difficult it will be to achieve the cement-job objectives.

Tools such as 2D numerical fluid displacement simulators are instrumental in analyzing and understanding the effects of each well parameter and can be a powerful aid to optimize the cementing operation in ever more challenging wells.

The objective of well cementing no longer stops at the end of cement placement but encompasses the maintenance of zonal isolation throughout the life of the well.
Primary cementing techniques are the same regardless of casing-string purpose and size. The cement slurry is pumped down inside the string to be cemented, exits the bottom, and displaces drilling mud as it moves up the annulus. Details vary from casing to casing, and the differences in placement technique are discussed in this chapter. It is assumed that the reader is familiar with the previously presented supporting material: Chapters 5 (Mud Removal), 9 (Annular Formation Fluid Migration), 11 (Cementing Equipment and Casing Hardware), and 12 (Primary Cement Job Design) in particular.

13-2 Classification of casing strings

A series of casing strings is necessary to complete most oil and gas wells and produce the desired fluids successfully (Fig. 13-1). The design of the casing program is contingent upon several factors. It starts with the production casing, which must be large enough to accommodate the expected completion for the anticipated production rate, and the design works backwards to the surface, adding one more casing size as particular zones must be protected or isolated. The complete program, which depends on the availability of drilling and completion tools and equipment for each size, is designed to ensure that the well is drilled and operated safely throughout its lifetime.

Casings are primarily classified by their size (outside diameter [OD], or outside diameter of the body of the pipe), material (carbon steel or corrosion-resistant alloy material), weight (lbm/ft or kg/m), yield strength (psi or N/mm²), type of connection (thread or coupling), and range (length of each casing joint). These characteristics give the casing string certain mechanical properties, such as tensile-, burst-, and collapse-pressure ratings. The most common casing connections are threaded connections, although quick-makeup mechanical connectors are available in the large sizes.

Figure 13-1 also shows casing strings known as liners. A liner is a string of standard casing that does not extend all the way to the surface; instead, it is hung from inside the previous casing string. Liners are covered in detail later in this chapter.

The string type and its function govern the casing-string design. The selection of a particular casing primarily depends on the

- depth
- hole sizes in which the casing string is to be set
- required tightness and torque resistance of connections
- mud-column and formation pressures
- condition of the formation
- drilling objectives.

The casing is designed to withstand the mechanical and chemical stresses in the well (Lubinski, 1951; Oil-Well Cementing Practices in the United States, American Petroleum Institute [API], 1959; Smith, 1987). A methodology known as the Service Life Model (Klementich and Jellison, 1986) analyzes the influence of any drilling, completion, or production event on the burst, collapse, and tension and/or compression resis-

The casing must be designed to withstand all loads imposed during installation and throughout the lifetime of the well. In particular, the innermost string of casing (hereafter defined as production casing) is an integral part of the well architecture, designed to maintain well integrity under severe conditions. Such conditions include: a well full of gas (subsequent to a tubing failure), an empty well, hot flowing production fluids, and injection of cold treatment fluids. The cements supporting and isolating these respective casings must also withstand the same conditions throughout the life of the well. In this section, the functions of the casing strings, the depths to which they are normally set, and special considerations for each are discussed.

Expandable casing tubulars are an alternative to conventional casings. They are covered in detail in Section 13-6.2.

13-2.1 Conductor pipe

The conductor is usually the first and shortest casing string. Its purpose is to protect shallow formations from being contaminated by drilling fluids and help prevent washouts that can easily occur near the surface in unconsolidated topsoils and sediments. The conductor pipe also serves as a conduit to raise the circulating fluid high enough to return to the mud system and enables a diverter to be installed should gas sands, for example, be encountered at a shallow level. The conductor pipe is designed to provide structural support for all subsequent casing and tubing strings and blowout preventers (BOPs) as well as the wellhead when the ground support
is inadequate. Therefore, the conductor must be set deeply enough into firm ground that it will not subside when subjected to the additional loading. Offshore, the conductor should be designed to withstand loads imposed by waves and currents.

At certain offshore locations or during swamp barge operations, driving or jetting the conductor into the ground is a common practice. A pile-driving hammer is used, and sections of conductor casing are welded together as they are driven into the ground. Increasingly, mechanical connectors are used because they offer significant rig time savings over welded connections. However, the mechanical connectors must be driveable. The setting depth is usually less than 300 ft [91 m]. It is often determined by the limitations of the pile driver as the conductor begins to encounter firmer ground. Once driven to the maximum depth (depth of refusal), the conductor is then cut to the appropriate height below the drill floor (and above the water line in offshore applications), and a casing head is welded into place (Fig. 13-2).

The hole for the conductor is sometimes drilled (e.g., a 36-in. hole for a 30-in. conductor), and the pipe is made up and lowered in a manner similar to conventional
casing. Most often, a guide shoe is welded on to help lower the conductor into the well. Cementing of the conductor is performed through a swage, which is screwed to the top of the conductor. The cement slurry is pumped through the swage and into the pipe. If the length of the conductor is short, the annular and pipe volumes are relatively small, and cement slurry is pumped until returns are observed at the surface. Cement slurry is then displaced from the casing without the use of plugs. Alternatively, and particularly for longer conductors, the stab-in technique or inner string cementing can be used. These techniques allow pumping of a minimum volume of cement slurry and limit slurry contamination during displacement (see Section 13-3.1).

In deepwater wells, conductor casings were initially drilled and cemented, because techniques for driving piles at such great depth were not available. Unfortunately, this often resulted in large, washed-out holes owing to the presence of soft and fragile surface sediments. It was not uncommon to pump 300% excess cement slurry yet not observe cement returns on the seafloor. Today, the conductor casing, such as a 30-in. casing, is more frequently attached to a 26-in. or 24-in. bit and drilling assembly and lowered at the same time the hole section is drilled. This jetting casing-drilling operation minimizes the disturbance of the soft formations. At casing depth, the conductor is simply disconnected from the drilling assembly and left uncemented as a guide for the fluids. Drilling of the 20-in. or 18\(\frac{5}{8}\)-in. surface-casing section can then proceed without delay.

In shallow-casing jobs, washouts and lost circulation often prevent the cement from reaching the surface. Normally, the necessary volume of cement slurry is estimated before the job, then mixed and pumped downhole. If the washouts prevent the cement slurry from reaching the desired height, a top-up job must be performed (Section 13-3.2). If lost circulation occurs after mixing is completed, the casing volume must be displaced, requiring the pumping of large quantities of cement into the loss zone (Chapter 6).

13-2.2 Surface casing

The second string of casing, which serves to case off relatively shallow unconsolidated formations and aquifers, is known as surface casing (Fig. 13-3). In addition to maintaining hole integrity, the surface casing prevents the contamination of fresh groundwater by drilling fluids, subterranean brines, oil, or gas. Depending on the country, there are usually government regulations stipulating minimum casing requirements and set-cement properties (Chapter 12), particularly regarding the protection of aquifers.
Surface casing must be set within competent formations to allow the installation of BOPs (Fig. 13-4) before drilling into potentially hydrocarbon-bearing and pressured formations. It is the first casing string for pressure-control purposes. Therefore, the selected casing must be strong enough to support a BOP and withstand the fluid pressures that may be encountered. Surface casing also provides a solid anchor for the casing head when the well is put on production. The surface-casing sizes and setting depths vary considerably; generally speaking, diameters range from 7 to 26 in. and depths can reach 12,550 ft [3,825 m] (Fontenot, 1986).

A major problem associated with cementing surface casing is placing the required annular height of cement slurry (often to surface) when the hydrostatic pressures of the slurries exceed the formation fracture pressure. The use of low-density slurries and foamed cement slurries is becoming more common in such circumstances.

**Fig. 13-3.** Typical one-stage primary cement job on a surface casing string.
Washouts are another frequent problem. When the borehole is enlarged by washouts, its size often exceeds the measuring capability of caliper tools. Unless adequate information is available from similar offset wells, accurate hole volumes may not be obtainable.

A through-drillpipe stab-in cementing system can be used in some surface casing cementing operations, but often this is not possible when using smaller-size surface casing or when larger sizes are run beyond 4,500 ft [1,500 m]. Drilling rig design constraints become the limiting factor in these applications.

Cementing of surface casings traditionally has been performed in stages when severe lost-circulation zones or other troublesome intervals were encountered. Today, they are frequently cemented in a single-stage operation using high-performance, low-density cement systems (Chapter 7; Al-Suwaidi et al., 2001).

Surface casing strings often encounter sloughing shales and shallow gas pockets (Chapter 9). These are some of the most difficult casing strings to cement successfully. Low formation temperatures prolong the thickening times of conventionally extended cement slurries, and the large annular cross-sectional area (even in a gauge hole) often prevents achieving the flow properties required to ensure efficient mud removal. High-solids, high-performance lightweight cements, which combine fast setting characteristics and high viscosity at low density (Chapter 7), are particularly useful in deepwater wells. Effective laminar flow is the recommended displacement regime in such large annuli (Chapter 5).

Large-diameter casings, with ODs equal to or greater than 18% in., are subject to large upward forces during cementing. Such casings have a large cross-sectional area upon which the pumping pressure can act. Unless preventive measures are taken, the upward forces may exceed the buoyed weight of the casing, and the casing will rise out of the hole (Appendix C). To prevent such problems, the pump pressure can be controlled, the density of the mud used to displace the slurry can be adjusted, or the casing can be physically restrained by various methods.

**13-2.3 Intermediate casing**

The intermediate casing isolates hydrocarbon-bearing, abnormally pressured, fractured, and lost-circulation zones, as well as problem shales and similar geological horizons. Intermediate casings are set within more competent formations than the surface casing, providing greater blowout protection when drilling deeper than the previous casing would allow. Any casing string run between the surface casing and the production casing is an intermediate casing string.

One or several intermediate casings are generally employed to seal off weak zones that might fracture and cause lost circulation in the presence of high-density mud. Such muds are usually required as well depth increases.

Occasionally, salt or anhydrite formations might dissolve and leach out, causing drilling-fluid contamination or pipe sticking. Salt formations have a natural tendency to creep or swell, a phenomenon likely to cause stuck pipe while drilling and casing collapse unless precautions are taken (Chapters 6 and 7).
Sometimes an intermediate string seals off older producing zones, allowing the operator to drill deeper.

Intermediate strings may seal shallow permeable formations containing uneconomical hydrocarbons or permeable zones that have been charged by gas leaking through poorly cemented annuli in nearby wells.

Intermediate casings protect the hole in deviated sections, particularly through unstable formations.

High-pressure, noncommercial fluid zones, which may be encountered well above the targeted pay zone, can be hydraulically sealed.

An intermediate casing also provides better protection against well pressure than the surface string, owing to its smaller diameter and the availability of higher steel grades. The setting depth of an intermediate casing should be sufficient to drill the next hole section without the hydrostatic pressure of mud exceeding the formation fracture pressure.

With the advent of high-performance lightweight cements, the casing string can usually be cemented in a single-stage primary job. However, a multistage job may be necessary under certain circumstances:

- if the column of cement slurry would exert a hydrostatic pressure greater than the formation-fracture pressure
- for the isolation of a lost circulation zone
- for imperatively isolating an hydrocarbon layer.

Figure 13-3 is an illustration of a single-stage primary job. Figure 13-5 depicts a typical two-stage cement job on an intermediate casing string.

![Fig. 13-5. Typical two-stage cementing sequence of an intermediate casing string.](image)
13-2.4 Production casing

The production casing or production liner is the last tubular element in the well. It isolates the different zones above and within the production zone and withstands all of the anticipated loads during testing operations and production throughout the well’s life. Any casing or liner that creates an annular space with the production tubing is treated as a production casing or liner.

Setting the production casing string is one of the principal objectives when drilling a well. In many respects, the production string is the oil well. It is the protective housing for the tubing and other equipment used in a well. Tubing may be pulled out of the hole for change or inspection, or if there is a completion equipment malfunction, but the production string is cemented in place. Indeed, special attention is usually devoted to ensure a pressure-tight bond between the formation and the production string. Common sizes range from 4 1/2 to 9 5/8 in. Depths can vary from 1,500 to more than 25,000 ft [460 to more than 7,620 m].

The production casing is normally run and cemented through the zone to be produced and then perforated to allow communication with the formation of interest (for producing reservoir fluids or injecting fluids). Sometimes it is set just above the zone of interest, and an openhole completion is performed. The casing should be the best-quality pipe that is appropriate for the conditions involved, including the potential for long-term corrosion. A small leak can develop into a blowout; therefore, the threaded connections should be appropriate for the anticipated pressures. To guard against leaks, the casing joints should be carefully connected as the casing is run into the well. Torque should be applied corresponding to the thread compound used. If casing rotation is an element of the mud-removal strategy, premium connections that can withstand the torque should be used. Different designs with proprietary pipe-thread geometries and metal-to-metal seals are available for gas tightness and should be used whenever the operating conditions demand reliable pressure-tight sealing and 100% connection efficiency.

Excellent primary cementing of production casings is essential. The cement slurry must be designed to keep the producing zone under control by providing adequate hydrostatic pressure. Preflushes and spacers run ahead of the slurry must also be checked to maintain hydrostatic overbalance and to maintain well control at all times (Chapter 12).

Zonal isolation is imperative both to protect the pay reservoir from fluid migration and crossflow and to isolate the pay hydraulically for any future stimulation treatments. In addition, the cement slurry must have adequate fluid-loss control to minimize the amount of filtrate lost to the zone. Good fluid-loss control minimizes damage to the critical wellbore matrix and prevents premature slurry dehydration in the annulus, which could result in annular bridging and a failed cement job. Fluid-loss rates should be less than 100 mL/30 min, preferably in the 50 mL/30 min range (Chapter 6). In the case of high-pressure, high-temperature wells, the fluid-loss rate must be less than 50 mL/30 min.

Achieving hydraulic isolation across, above, and below the pay zone is essential. With conventional cement slurries, an important property of the set cement is compressive strength. The set cement must also have low permeability to prevent fluid invasion. Set-cement permeability is directly related to water content and inversely related to cement content and strength. The general guideline for adequate zonal isolation is 1,000-psi [7.0-MPa] compressive strength and less than 0.1 mD water permeability. Strength retrogression must be prevented when the bottomhole static temperature exceeds 230°F [110°C] (Chapter 10). This condition, which also applies to any cement used in surface and intermediate strings that will be exposed to producing temperatures greater than 230°F [110°C], is generally fulfilled by adding 30% to 40% by weight of cement silica flour to the Portland cement.

When pressure and temperature variations are anticipated during production, injection, or well maintenance, special cements with tailored mechanical properties (Young’s modulus, Poisson’s ratio, and tensile strength) are available to maintain isolation throughout the life of the well (Chapter 7).

In shallow wells that are not prolific producers, a small cemented casing can be substituted for the production tubing. Such tubingless completions are less expensive. Sometimes this technique is used in miniaturized dual completions, in which two separate casing strings are run and cemented in the same wellbore. Such completions are cemented in a single operation using completion brine as the displacement fluid.

13-2.5 Combination casing strings

In casing-string design, it is common to vary the casing weights (internal diameters) or grades within a nominal size range because of load considerations, cost savings, and the available casing inventory. However, to minimize the risk of errors in the pipe running sequence, one should not use more than two types of casing joints in a given casing string. These factors must be known when designing the cement job, because burst and collapse ratings are affected, internal diameters vary, and thread connections may change within a particular string.

Another technique is to actually vary the nominal casing size. Commonly used combinations include...
10\% in. and 9\% in. and 7\% in. and 7 in. Installing such combinations requires the casing to remain stationary in the rotary table for a substantial amount of time—the time required to change the casing handling equipment (slips and elevators). The end result is similar to a liner completion. The larger-internal-diameter (ID) casing may be desirable in dual completions or in gas wells in which additional tubular completion equipment is required, such as side-pocket injection mandrels or in offshore wells requiring subsurface safety valves.

Figure 13-6 depicts a typical tapered string completion. This particular example was completed to accommodate an additional tubing string that could be run to the bottom of the 7\%-in. casing.

The only special cementing considerations for combination strings are for the displacement plug. The most common practice involves modifying the displacement plug of the larger-diameter casing. The core of the plug is machined to a size less than the ID of the smaller casing. As a result, the wiper fins aid displacement in the larger-diameter casing. Because of their flexibility, the plug will fold and pass through the smaller casing. First-stage wiper plugs of the type used in stage cementing could also be considered.

### 13-3 Cement placement procedures

Most primary cement jobs are performed by pumping the cement slurry down through the casing and up the annulus (also called reverse circulation cementing) sometimes performed in the extreme case in which important lost circulation zones or fragile formations occur near the shoe but some cement is required to seal off an upper interval. This is typically a last-resort option, because fluid placement is largely uncontrolled and the shoe is never cemented. Modifying the float equipment is necessary to allow careful control and precise monitoring of the returns through the casing.

For large-diameter casings, the traditional cementing technique is frequently inadequate; consequently, cementing through the drillpipe or a grouting technique in which the cement is circulated into place by pumping the slurry down one or more small-diameter pipes placed in the annular gap is performed. When cementing intermediate or production casings, well conditions and the length of interval to be cemented influence the placement technique to be used. Usually, the maximum permissible downhole pressures determine whether a job should be performed in a single stage or in multiple stages. In this section, the most common procedures are described.

#### 13-3.1 Cementing through drillpipe (stab-in or inner-string cementing)

As discussed earlier, performing the job through drillpipe can prevent many problems related to cementing large casings. With the stab-in technique, which can only be used on stationary rigs (land rigs and jackup or platform rigs), the casing is run in place with a stab-in float shoe. The casing is set in the casing slips, thus suspending the string off bottom. Drillpipe made up with a stab-in stinger (Fig. 13-7) is then run in the casing until it is approximately 3 ft [1 m] above the float shoe. Circulation with the drilling fluid is then established, and returns come from the annulus between the drillpipe and the casing. Circulation is stopped and the drillpipe is lowered, enabling the stinger to stab or screw into and seal in the float shoe. While a constant watch is maintained on the fluid level in the casing-drillpipe annulus, which must remain stationary, circulation is broken again, and one typically observes returns flowing between the conductor pipe and the casing. Cement is mixed and pumped through the drillpipe and up the annulus until the slurry reaches the surface. As soon as mud contamination is no longer evident in the cement returns, mixing can be stopped and the drillpipe volume displaced.

If lost circulation is noticed before the cement reaches the surface, mixing should be stopped and the cement displaced, avoiding the pumping of large quantities of cement into the fractured zone. Also, care must be taken to avoid casing collapse because of excessive differential pressure between the outer annulus and the drillpipe-
casing annular space. Special packoff cement head assemblies can be used to seal the drillpipe-casing annulus and allow pressure to be applied. This pressure serves to offset the pump pressure that creates collapse loading whenever inner-string cementing operations are conducted. Alternatively, mud of an adequate weight can be pumped in the drillpipe-casing annulus before stabbing.

Through-drillpipe cementing has several advantages. Accurate hole volumes (most often unknown in conductor or surface holes) are not required, because the cement slurry is mixed and pumped until returns are observed at the surface. This procedure optimizes the total volume of cement mixed and pumped and virtually eliminates the possibility of overdisplacement because the subsequent volume displaced from the drillpipe is negligible. This method also eliminates the need for large-diameter swages or cement heads, as well as large-casing wiper plugs. Also, minimal cement contamination occurs during through-drillpipe cementing.

Various options are possible with the through-drillpipe stab-in technique. A backup check valve (float collar and float shoe) can be run as depicted in Fig. 13-7. Alternatively, a stab-in float shoe alone could be used. The types of available stab-in tools offer the possibility to latch into the float collar or shoe, thus preventing pumpout of the stinger while cementing. Upon completion of the cementing operation, the drillpipe is rotated to the right for several turns, and the coarse threads release the stab-in tool. Simpler stab-in tools are also commonly used that omit the latch-in design and simply rely on the drillpipe weight to hold the stinger in place while cementing. Special drillpipe centralizers centralize the stinger and the last few joints of drillpipe, particularly in deviated wells.

Collapsing the casing is the greatest risk in stab-in cementing operations. This may occur if the annulus becomes blocked for any reason. A preferred adaptation of through-drillpipe stab-in cementing is therefore offered by using a cementing mandrel (Fig. 13-8) with the drillpipe (or tubing) hanging freely to within 15 to 30 ft [4.6 to 9.2 m] of the shoe or collar. This type of arrangement, often called inner string cementing, offers the additional possibility of casing reciprocation. In addition, unlike the stab-in technique, it can be used on a floating rig, in which the drillpipe hangs underneath the conductor (or surface casing) wellhead-housing running tool. Above all, it eliminates the possibility of casing collapse, because the pressures in the annulus and within the casing are equal. Pressure inside the casing (the drillpipe-casing annulus) can be monitored at the packoff head (on a stationary rig). However, during U-tubing, the column of fluid in the drillpipe-casing annulus is not controlled, resulting in possible cement-slurry contamination.
13-3.2 Grouting (top-up cementing)

When lost circulation occurs during large-casing slurry displacement, the immediate solution is to recement down the annulus. On land, a small-diameter tubing string is run down the annulus between the casing and the open hole (1 3/4-in. [5-cm] tubing is a common size). Several joints can be made up together and pushed down the annulus as far as possible. The tubing string is then connected to the cementing unit through a high-pressure treating line, and circulation with drilling mud or water is established. Caution must be exercised, because friction pressures will be high because of the small tubing ID. Cement slurry is then mixed in the conventional manner and pumped—often with centrifugal pumps—only until cement slurry is circulated to the surface. The lines and tubing are flushed with water, and the tubing (if still hanging freely) is withdrawn from the annulus (Fig. 13-9).

The cement slurry can also be mixed and pumped directly into the annulus with the tubing string in place. In extreme cases, such operations may have to be repeated several times until the cement slurry returns to the surface and sufficient gel strength builds to support the slurry until it sets. However, when attempting to fill the casing annulus from the surface, there is no method to determine how deeply the cement has fallen, and the casing annulus may not be uniformly cemented.

Small-diameter tubings are not as easy to use offshore. Therefore, a special tool, called a Titus Assembly, is run as a contingency measure on the landing joint at the same time as the casing. The primary cementation is performed through the swivel in the open position. After the primary job is complete, a ball is dropped, which diverts the flow through the swivel down a hose to the Titus Ring. Slow circulation for approximately 3 hr, while waiting for the cement at the shoe to set, removes any contaminated cement from the top of the annulus. Several 50-bbl [8-m³] top-up jobs are then performed though the ring to ensure the placement of strong cement to the surface.

† Mark of Titus Tools
Exposed weak formations make cementing to the surface problematic. When a top-up job is anticipated, cement baskets are positioned within the previous casing. They allow a first cementing operation to form a ring of cement, used later after its initial set to support further top jobs until the cement reaches the surface.

13-3.3 Single-stage cementing

With the development of new ultralow-density cement systems (Chapters 3 and 7), the need for multistage cementing has been significantly reduced, if not eliminated. A long column of low-density, high-solids, or foamed cement can often be placed in the annulus in one stage without the risk of breaking down weak formations.

13-3.3.1 Mud conditioning

After the casing is in place, the mud is circulated as long as necessary to remove high-gel-strength mud pockets formed during the semistatic period of removing the drillpipe, logging, or running the casing. Mud circulation is usually performed through the cement head to avoid stopping for an excessive period of time after the mud has been conditioned. Under static conditions, mud gel strength can develop quickly and may greatly reduce the mud removal efficiency (Chapter 5). In case of gas cutting, mud circulation must continue until a steady in-out mud weight is obtained. In addition, cementing should not take place before the well is completely static.

If a single-plug cement head is used, circulation must be stopped before cementing to load both cement plugs. The bottom plug must be placed below the lower 2-in. [5-cm] inlet to allow room for the upper plug between the two inlets. If a double-plug cement head is used, both cement plugs can be loaded before starting mud circulation.

13-3.3.2 Bottom wiper plug

The bottom cement wiper plug is a key element in a cementing operation. It serves two functions: it prevents the intermixing of fluids and it sweeps clean the inner wall of the casing. The most obvious function of the bottom plug is to prevent mud from contaminating the cement slurry. Fraser et al. (1996) and Griffin and Valkó (1997) demonstrated that failing to use a bottom wiper plug was the cause of many primary cementing failures. However, if the bottom wiper plug is properly located, it can also contribute to the conservation of spacer or slurry properties. As discussed in Chapter 5, rheology has a crucial effect on the ability of a spacer fluid to remove mud. A small amount of mud contamination can alter characteristics and reduce effectiveness. Another role of the bottom wiper plug is to prevent heavy fluids (spacer or cement slurry) from falling through lighter ones (chemical washes and drilling fluid).

When a spacer is used, sinking of the cement slurry through the spacer will occur to a lesser extent, because the density differential between the two is usually not very large. If a plug is run between the spacer and the slurry but not between the spacer and the mud, the spacer will become contaminated with mud during the trip down the casing. In addition, the plug will sweep the casing wall clean, pushing accumulated mud film ahead and contaminating the last portion of the spacer. Once the bottom-plug diaphragm breaks, a mud-contaminated spacer will be in contact with the cement slurry—a situation the spacer was supposed to prevent. Depending on the type of mud and its compatibility with spacer or with cement, this situation can be circumvented by pumping a sacrificial volume of spacer or cement. Clearly, the ideal situation would be to use two bottom plugs to avoid intermixing of all fluids during the trip down the casing. Three-plug cement heads are used at times (Fraser et al., 1996); however, these are not common. With present plug containers (cement heads), more than one shutdown would be necessary to load the plugs.

The following sequences are normally recommended when only one bottom plug is used.

- **Bottom plug—spacer—cement slurry**
- **Wash—bottom plug—spacer—cement slurry**
- **Wash—bottom plug—cement slurry**

As a general practice, the bottom wiper plug should be placed between the fluids of highest density difference, provided a sacrificial volume is tolerated for the contamination between the other fluids, usually spacer and cement. These latter fluids are designed to be rheologically compatible, but contamination of the cement by the spacer may result in retardation. Therefore, the bottom plug is often dropped in the last portion of the spacer, meaning that the actual sequence is

- **Spacer—bottom plug—spacer**
  (last portion or sacrificial volume)—cement slurry.

13-3.3.3 Displacement procedures

Dropping the top wiper plug is an easy operation and should not take longer than the time needed to open and close the valves at the cement head. Cement heads are very reliable tools under normal working conditions and are designed to minimize time delays. Stopping circulation for long periods of time (5 to 10 min) allows downhole fluids to develop high gel strength. Remotely operated cement heads (Lavaure and Galiana, 1991) facilitate the wiper plug dropping exercise and increase
safety by not requiring someone to climb the mast to operate the valves and launch the plugs. There are two principal consequences when plug launching is delayed.

- Additional applied pressure may be required to restart fluid movement. In extreme cases, this pressure may exceed the fracture pressure resulting in lost circulation.
- Poor removal of gelled mud may occur, leading to poor zonal isolation.

The spacer and slurries are then displaced through the casing, isolated between the two wiper plugs. In reality, because of U-tubing (Chapter 12), the top of the cement column may be at a considerable depth below the surface at the time the top plug is released. Depending upon the mud density and the cement volume and density, the first part of the cement column may have already rounded the shoe. Computer programs for cement-job design (Chapter 12) can predict such phenomena. The rate at which the cement is displaced into the annulus is not the same as the pumping rate; instead, it varies depending upon the different fluid densities and volumes. This phenomenon continues until the fluid level inside the casing reaches the surface. Continuous flow can then take place.

In general, there is a tendency to disregard the importance of displacement rates during the period of U-tubing. If the job is designed for turbulent flow, the maximum pump rate possible is recommended during this period, because downhole fluid velocities are probably one-third to one-half of the surface pumping rate. For jobs pumped in laminar flow, the surface rate must be controlled to maintain the desired flow regime. Again, computer programs can calculate the optimal pump rates according to the well geometry and fluid properties. A tool to control U-tubing was introduced by Head et al., 1995. It did not gain popularity because the main use was in large casings. To be efficient, such tools must restrict the flow rate; as a result, the duration of the cement job increases and, owing to the low flow rates, mud removal may be questionable.

Once continuous flow is restored, the annular flow rate is equal to the pump rate, and the surface pressure begins to increase as the rest of the cement is placed behind the casing. Displacement then continues at the programmed rate until the top wiper plug bumps in the float collar. However, the pump rate is usually reduced at the end of the displacement to avoid a sharp pressure increase when the plug reaches the collar. On bumping the plug, one should watch for leaks. If pressure holds after bumping, the casing can be immediately pressure tested, provided that the plugs and collar have been selected to withstand such extra differential pressure without collapsing or breaking.

Surface pressure is then released, and backflow is observed to test the functioning of the float equipment. If no returns are observed, the line is left open during the waiting-on-cement (WOC) period. If the float-collar valve does not hold the backpressure, the fluid returned during the test must be pumped back into the well, leaving the casing pressurized until the cement gels and loses mobility. However, it is very important to bleed off the excess casing pressure (caused by thermal expansion) before the cement begins to develop compressive strength; otherwise, a microannulus may form because of expansion and contraction of the casing.

Once the cement slurry has started to set, the normal practices and operations of putting the string in tension and landing it in the wellhead can be performed according to the casing landing procedure (see Section 13-7.8).

13-3.4 Multistage cementing

As mentioned previously, high-performance lightweight cements have made multiple-stage cementing a relatively rare event. However, multiple-stage cementing may still be necessary if

- downhole formations are unable to support the hydrostatic pressure exerted by a long column of cement
- the upper portion of the annulus must be cemented with a higher-density cement system
- cement is not required between widely separated intervals.

Most multiple-stage cement jobs are performed to alleviate high hydrostatic pressure. It is not uncommon to cement a long string to the surface to protect the casing from corrosion. Another scenario might be the presence of lost circulation zones below the last casing shoe that prevents cement slurries from reaching the surface. Two-stage cementing, with the top of the first-stage covering the weak zone, will permit safer, more complete filling of the total annular space.

Three standard multistage techniques are commonly employed.

- regular two-stage cementing, in which the cementing of each stage is a distinct and separate operation
- continuous two-stage cementing, with both stages cemented in one continuous operation
- three-stage cementing, in which each stage is cemented as a separate operation

The longer execution time of stage cementing increases the rig time. In addition, most cement heads cannot accommodate the preloading of all the plugs and bombs required in the operation sequence. As a result, the cement head must be opened to release the opening
bomb, assuming the first-stage plug was preloaded. The shutoff plug could be loaded after the bomb is released, but caution should be exercised to ensure that all of the plugs and bombs are compatible with the cement head. In addition, the plugs should be carefully checked for correct fitting in the head.

Hydraulically operated stage collars are commonly used in deviated wells in which it would be difficult for the opening bomb to reach the collar by gravity and seal properly to operate the opening sleeve. However, even when using a hydraulically operated tool, it is prudent to have an opening bomb available as a contingency.

Figure 13-10 shows the operation of mechanical and hydraulic stage tools.

**Fig. 13-10.** Operation of mechanical (top) and hydraulic (bottom) stage collars.
13-3.4.1 Conventional two-stage cementing

In addition to conventional casing equipment (e.g., guide shoes and float collars), a stage-cementing collar (Chapter 11) is run to the desired depth. There are several types of two-stage collars. It is important to be completely familiar with the operation of the selected type and to follow the manufacturer's operating recommendations. All stage collars must be handled with care, as they are manufactured to close tolerances. Smooth sliding and sealing of the concentric sleeves is necessary for proper operation. Rough handling before or during installation can “egg” or misalign the moving parts, causing a job-execution failure. One must also be absolutely sure that the float collar and the stage collar are compatible. The first-stage wiper plug (if used) and the first-stage displacement plug must fit and seal against the float collar.

To explain the sequence of stage cementing operations, a brief explanation of the equipment is necessary (Fig. 13-5). Conventional stage equipment consists of the following.

- A stage cementing collar is basically a casing joint with ports, which are opened and closed or sealed off by pressure-operated sleeves.
- A rubber sealoff plate is a part installed in the top float collar to assure a positive shutoff.
- A first-stage plug is a rubber plug used to separate the slurry from the displacement fluid; it gives a positive indication of the end of displacement.
- An opening bomb is a device that is dropped after the first stage and allowed to gravitate to the opening seat in the stage collar. Subsequent application of pressure will move the sleeve downward, opening the collar’s ports.
- A closing plug is a rubber plug that is pumped to a shutoff on the closing seat.

13-3.4.1.1 Cementing the first stage

The mixing and pumping of spacers and slurries during the first stage are similar to those of a single-stage job, except that in most cases there is no bottom wiper plug. After the mixing of the slurry, the first-stage plug is dropped and displaced until it lands in the float collar. When cementing production strings, some operators displace the first stage using two fluids, leaving the casing below the stage collar filled with completion fluid and the upper casing filled with drilling mud. This mud is subsequently used to circulate the hole through the stage-collar ports.

Accurate hole volumes are necessary to determine the correct slurry height in the annulus; therefore, a caliper log should be mandatory on all multistage cementing jobs. The first-stage slurry should cover the stage collar. Any excess can be circulated out when the ports are opened. Some types of stage collars allow the use of first-stage wiper plugs. First-stage displacement plugs are mandatory and must be compatible with the original stage collar and the float collar. Plugs and stage collars from different manufacturers should never be mixed.

It is a common mistake to leave a portion of the first-stage openhole section uncemented. Unless an annular packer is coupled to the stage tool, the second-stage cement slurry will fall downhole, resulting in a poor second-stage cement job.

In case of high incompatibility between the cement and mud, it may be desirable to run a bottom wiper plug ahead of the slurry in the first stage. To do so, the following additional equipment must be used.

- Flexible plug: This special wiper plug is pumped ahead of the first-stage slurry.
- Bypass insert: This part, located above the float collar or float shoe, provides a seat for the flexible plug but allows continued circulation of slurry through its ports.
- Special insert collar: This collar, located above the bypass insert, provides a seat for the special first-stage plug that follows the cement.
- Special first-stage plug: This plug, provided with a head that is shaped to seal off in the insert collar, replaces the first-stage plug in conventional stage equipment.

The sequence of operations is similar to that of the conventional two-stage cementing procedure, except that the additional wiper plug is launched ahead of the first-stage slurry or spacer.

13-3.4.1.2 Cementing the second stage

After the first stage is completed, the opening bomb of a mechanically operated stage collar is dropped and allowed to fall by gravity to the lower seat in the stage collar. Once the bomb is seated, pressure is applied until the retaining pins are sheared, forcing the lower sleeve to move downward and uncover the ports. Usually 1,200 to 1,500 psi [8.4 to 10.5 MPa] will shear the retaining pins. A sudden drop in surface pressure indicates the opening of the ports. This operation is performed as soon as possible after the completion of the first stage. Under normal circumstances, the excess cement from the first stage will sit above the stage collar and must be circulated out of the hole before it develops excessive gel strength.
When using a hydraulically operated stage tool, the displacement of the first stage must be complete; i.e., the first-stage plug must have landed on the float collar. Then pressure is gradually increased until the opening pressure is attained.

Once the stage-collar ports have been opened, the well must be circulated until the mud is conditioned for the second stage and the first-stage cement is set. Otherwise, the weak zones along the first-stage section may not withstand the hydrostatic pressure from the second-stage cement column. For cementing the second stage, spacers and slurries are mixed as in any single-stage job. The closing plug is dropped after the slurry mixing and displaced to its seat in the stage collar. After the plug has seated, a minimum of 1,500 psi [10.5 MPa] above the second-stage displacing pressure is required to close the stage-collar ports. Pressure is usually released from the casing after the ports are closed.

Most second stages of two-stage jobs are performed using low-density filler slurries to allow circulation to the surface. Normal-density slurries are used when a high-pressure zone or an aquifer must be thoroughly isolated. Protection of the weakest point in the casing string, the stage collar, can be improved by simply increasing the density of the last portion of the cement slurry.

13-3.4.2 Continuous two-stage cementing

Sometimes the situation demands that the cement be mixed and displaced without stopping to wait for an opening bomb to gravitate to the seat in the stage collar. This is known as the continuous-stage cementing method (Fig. 13-11). This method is presented as a historical reference, because it is rarely used. This technique requires tight control of fluid volumes and does not address the objective of a multistage operation—to isolate the top section when lower weak zones are present.

The first stage of cement is mixed and pumped into the well. A wiper plug follows the cement to separate it from the displacement fluid. Following the plug, sufficient water or mud is pumped to displace the cement out of the casing below the stage collar. Allowance must be made for compression and pipe stretch so that the cement is not overdisplaced around the casing shoe. Overdisplacement is also possible owing to a bypass insert that is installed above the float collar on which the cement wiper plug lands. This insert prevents a shut-off when the plug lands and permits some tolerance in the displacement fluid volume. After this displacement fluid has been pumped, the stage-collar opening plug is released.

The second stage of cement may be pumped immediately behind the opening plug. The closing plug follows this slurry. Displacement of this slurry will cause the opening plug to seat on the opening sleeve. When pressure is applied, the sleeve will open the collar ports. Further pumping will displace the slurry through the ports and eventually land the closing plug on the closing seat. Application of 1,500 psi [10.5 MPa] above the circulation pressure will close the tool.

Fig. 13-11. Continuous two-stage cementing.
13-3.4.3 Three-stage cementing

The three-stage cementing technique is also presented as a historical reference, because it is rarely applied. It multiplies the operating time, complicates the operation, increases the number of weak points in the string, and significantly increases the failure risk. A single collar malfunction is sufficient to ruin the entire job.

Weak zones in deep wells, combined with gas channeling or potential casing corrosion problems, may require a three-stage cement job. The basic procedure is similar to two-stage cementing (Fig. 13-12). The first stage is performed through the shoe, the second through a regular two-stage collar, and the final stage through a top-stage collar. The first stage is performed through the shoe in the conventional manner, using a first-stage plug to shut off at the float collar. The second stage could be performed at any time after the first, depending upon the cement program.

A regular opening bomb is used to open the ports of the lower-stage collar. The well is circulated, and the spacers and slurries are pumped through the ports. The ports are closed using a special closing plug, which replaces the regular closing plug. This flexible type of plug passes through the top-stage collar and seats on the lower collar, allowing the application of pressure to close the ports.

The final stage can also be performed at any time after the second one. An opening bomb (larger than the one used for the second stage) is dropped and allowed to gravitate to the lower seat of the top-stage collar. Ports are opened, and the final stage is performed as usual. A special closing plug is then used to close the collar ports.

Figure 13-13 summarizes the different types of plug used in multistage cementing operations.

<table>
<thead>
<tr>
<th>Plug Type</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>First-stage sealing plug</td>
<td>Used in the first stage to seal off the well at the float collar.</td>
</tr>
<tr>
<td>Pumpdown opening plug</td>
<td>Used to pump down the cement slurry through the ports in the second stage.</td>
</tr>
<tr>
<td>Shutoff baffle</td>
<td>Used to close the ports in the second stage.</td>
</tr>
<tr>
<td>Bypass plug</td>
<td>Used to bypass the closing plug in the second stage.</td>
</tr>
<tr>
<td>First-stage shutoff plug</td>
<td>Used to shut off the ports in the second stage.</td>
</tr>
</tbody>
</table>

![Fig. 13-12. Three-stage cementing.](image)

![Fig. 13-13. Plugs used in multistage cementing operations.](image)
13-4 Liners

A liner is a string of standard casing that does not extend all the way to the surface; instead, it is hung from inside the previous casing string. The overlap depends on the purpose of the liner and could vary from 50 ft [15 m] for drilling liners to as long as 500 ft [152 m] for production liners. Liners can be classified as follows (Fig. 13-14).

- **Production liners** are run from the last casing to total depth. They replace production casing. Cementing is usually critical, because zonal isolation is essential during production and any subsequent stimulation treatments.

- **Drilling or intermediate liners** are set primarily to case off and isolate lost-circulation zones, overpressured zones, sloughing shales, or plastic formations. This is necessary to resume drilling. Cementing these liners is often difficult.

- **Tieback stub liners** extend from the top of an existing liner to a point uphole inside another casing. They are generally used to repair damaged, worn, corroded, or deliberately perforated casing above the existing liner and to provide additional protection against corrosion or pressure. In addition, they must be designed to perform within the casing-design envelope for the well.

13-4.1 Running a liner

Like a standard casing string, a liner is assembled joint-by-joint at the rotary table and lowered into the well. When liner rotation is planned during the cement job, premium connections that can withstand high torque are required. Float equipment is also included, and sometimes a landing collar (typically one joint above the float collar) is used to provide a seat for the liner wiper plug. The dart and plug system must be compatible with the float collar.

Centralizers are essential in liner cementing. Because annular clearances are usually small, the liner must be kept clear of the borehole wall. The mud displacement efficiency improves significantly with better centralization (Chapter 5). Centralizers also help prevent the liner from becoming stuck while running in the hole and make liner reciprocation and rotation during cement displacement easier and more effective.

A liner hanger is placed at the top of the liner (Fig. 13-15). The hanger is often combined with a packer, or sometimes provision is made for a tieback receptacle to allow running an isolation packer at a later date, if required. When set at the desired depth, this supports
the weight of the liner string. Therefore, the liner is kept under tension, which prevents it from buckling under its own weight. The liner hangers have slips that, when set, close tightly into the upper casing and provide the anchor to suspend the liner. There are two types of liner hangers, depending on the hanger setting mechanism: hydraulic (pressure-activated) or mechanical. The choice between the two types of hanger primarily depends on the rig type (floater or stationary rig) and the well type (deviated or not). In addition, the hanger design may provide the ability to rotate and/or reciprocate the liner. The liner hanger remains permanently in place once the liner is cemented. In addition, the liner hanger may be coupled to or complemented with a packer.

Liners are usually run into the well using drillpipe and a special setting tool. The setting tool is retrievable; i.e., it is pulled out of the well with the drillpipe after the liner is run and cemented. It performs the following functions.

- It provides a pressure-tight seal between the drillpipe and the liner. Thus, fluids pumped into the drillpipe must circulate down inside the liner and out of the shoe before returning up the annulus.
- It holds the weight of the liner as it is run into the well.
- It provides attachments for the liner wiper plug system. The liner wiper plug, attached by shear pins, has a hole through its center to allow the passage of fluids and cement slurry until the drillpipe pumpdown dart closes it. Applied pressure will then shear the pins, and the wiper plug can be pumped down the liner behind the cement slurry. Because this system does not accommodate a bottom plug, drilling fluid contamination inside the liner often occurs, resulting in poor isolation. This is particularly troublesome in long liners. Systems with bottom and top plugs, called two-plug-dart systems, are available but are not widely used.

During the last trip out of the hole before a liner job, it is a common practice to gauge or drift the landing string to ensure the passage of the balls and pumpdown dart.

With the liner at the desired depth, but before the hanger is set, connections are made and the liner and hole are completely circulated. This conditions the mud and ensures that circulation is possible before the liner is hung. In some deep liner-setting assemblies, a circulation valve is included, which allows circulation to be established above the liner before closing the valve.

If the liner is not or cannot be reciprocated during cementing, the liner hanger is set, and the drillpipe and setting tool are then raised slightly to verify that the setting tool is released from the liner. The seal assembly holding the liner wiper plug is usually 10- to 15-ft [3.0- to 4.6-m] long to enable this operation to be performed without breaking the seal between the liner and the drillpipe.

If reciprocation is planned during cementing, the hanger can only be set after cementing.

13-4.2 Liner cementing procedure

13-4.2.1 Mud removal

The success of any cement job depends upon the mud removal efficiency. Liner cementing can be one of the most difficult cases. The annular space is small, and the pipe may not be well centralized. This subject is covered thoroughly in Chapter 5; nevertheless, there are certain points that deserve reinforcement.

A 5-in. OD liner, hung from a 7-in. casing inside a 61⁄8-in. drilled open hole, will have a maximum clearance of 9⁄16 in. [1.4 cm] if the liner is perfectly centered. The annular clearance will be less in some parts of the hole because of a thin, nonremovable mudcake on the wall of permeable formations. Crooked hole and small clearances between the casing and formation often inhibit the use of normal centralizers, resulting in liner eccentering. Under severe conditions, actual borehole contact occurs. Under these circumstances, it becomes much more difficult for cement slurries to remove mud. Small clearance centralizers, including those that allow liner rotation, are available and should be used to increase the chance of success of this critical cementing operation.

It is for these reasons that pipe movement during displacement becomes critical. Bowman and Sherer (1988) reported that less than 20% of liner jobs include plans to move the liner during cementing. There are many industry concerns about liner reciprocation and rotation:

- not becoming unlatched from the liner after cementing
- that a large, stronger drillstring may be required for fear of drillstring parting during pipe movement
- excessive drag caused by centralizers
- swabbing or surging the pay zone
- hole deterioration caused by moving pipe, which could lead to annulus bridging
- that the liner may become stuck and have to be cemented without the designed tension.
In fact, the advantages of liner movement during cementing far outweigh the concerns listed above. With the hole in good condition and correctly selected centralizers on the liner, fewer problems should be experienced, and certainly better cementing results should be achieved. Bowman and Sherer (1988) stated that, in their study of more than 300 liner jobs, the inability to release the liner setting tool had only occurred twice. Premature cement setting caused one failure, and the other involved a very early tool design that was subsequently modified.

Rotation frequently has advantages over reciprocation. If the liner were in contact with the hole at any point, up-and-down motion would not remove the drilling fluid effectively (Chapter 5). However, pipe rotation would allow slurry to be dragged behind the pipe, ensuring a cement sheath all around the liner. As stated by Bowman and Sherer (1988), the inability to rotate liners is often caused by insufficient starting torque. Once this has been overcome, the torque required for rotation will probably be much less (assuming good centralizer design).

Because of the above problems, using adequate volumes of washes and spacers is even more critical in liner cementing than in casing cementing. Maximizing the contact time of the spacer or wash generally increases the chances of a good cement bond. In conventional casing strings, contact time can be improved by simply increasing the volume of the scavenger slurry. However, in a liner situation, slurry volumes can be critical because of the formation’s hydrostatic-pressure limit.

Turbulent flow displacement is efficient for mud removal, but care must be taken not to exceed allowable downhole pressures. Fortunately, small annular clearances make it easier to accomplish turbulent flow at low pump rates. If a job must be performed in laminar flow, spacer volumes, rheological properties, and rates may be adjusted to allow for the adequate mud displacement.

### 13.4.2.2 Regular liner cementing

The liner cement head and manifold are installed on the drillpipe with the pumpdown slurry displacement dart placed between the two inlets. The dart-releasing stem holds the dart in the cement head (Fig. 13-16). After the cementing lines are rigged up and pressure tested, the chemical wash or spacer is pumped down the drillpipe. Usually, a bottom wiper plug is not used ahead of the spacer or slurry. However, two-plug liner cementing systems exist and are preferred. Figure 13-17 shows the single and tandem liner plugs.
Figure 13-18 shows the typical steps of liner cementing with a single plug system, and Fig. 13-19 depicts the operation with a two-plug liner system. If possible, the cement slurry should be batch-mixed to obtain a homogeneous slurry at the proper density. Once the slurry is mixed and pumped into the drillpipe, the pumpdown dart is dropped and displaced to the liner hanger. At this point, the pumpdown dart passes through the liner setting tool and then latches into and seals the hole in the liner wiper plug. The surface pressure will rise when the dart lands. Further applied pressure, approximately 1,200 psi [8.4 MPa], will shear the pins that hold the liner wiper plug in place. Such a pressure peak is often easily detectable from surface. Therefore, this is a reference point in the displacement volume because, until this moment, only the drillpipe has been displaced. After this moment, only the liner is displaced.
Fig. 13-18. Typical liner cementing sequence.
Once released, the dart-plug combination moves as one plug inside the liner while displacement continues. When the internal volume of the liner has been completely displaced, the plugs seat on the float or landing collar and another pressure rise occurs, indicating job completion. Monitoring the returns after bleeding off the pressure allows one to test the float equipment.

It can be noted that the displacement of the cement slurry for a liner generally takes place using the cementing unit rather than the rig pumps, because of the relatively small volume to displace. Hence, control of the displacement volume is made much easier.

If a packer-type liner hanger has been used, the packer between the liner and the upper casing may be set at this time, the setting tool is pulled free from the liner hanger, and any excess cement is reversed out. If lost circulation is observed while displacing cement, the packer is not set, thus allowing eventual squeezing of cement in the liner-casing annular space (also called liner overlap) (Chapter 14). If no packer is incorporated into the hanger, the reversing out depends on the quantity of excess cement expected and whether lost circulation is observed. This is an important decision in liner cementing design, because proper isolation of the liner overlap is critical. Software helps to make sure the well is kept under control when reversing out. If gas releases (kicks) or losses occur, the quality of isolation may be compromised.

The amount of cement excess must be carefully calculated by taking into account the well conditions and operator requirements. The following factors must be balanced:

- Sufficient excess cement slurry must be available to ensure the placement of uncontaminated cement in the liner overlap. A caliper with at least four arms should be run before the liner operation, and the slurry volume should be determined from the caliper logs. Graves (1985) pointed out that hole volumes could vary by as much as 31%. When the liner is not too long, it is common practice to use a slurry volume

![Fig. 13-19. Liner cementing with two liner plugs.](image)

**Fig. 13-19.** Liner cementing with two liner plugs.
corresponding to the annular volume with its normal excess, plus the overlap volume between the liner and the casing, plus any volume above the hanger. This procedure typically doubles the slurry volume but significantly increases the success by reducing cement contamination.

- Displacement efficiency also becomes a key variable in determining cement-slurry volumes. Although 100% efficiency is the ideal, it is not uncommon to have 60% to 80% displacement efficiency in liner cementing (Smith, 1990). The efficiency suffers as the interval length increases.

- If excess slurry is to be reversed out while not having a liner top packer, weak formations could pose a problem. Also the thickening time of such slurries must be extended to allow for the reversing operation.

- If reversing out is not scheduled, operators usually do not want to drill out long columns of cement; therefore, the excess slurry volume may have to be limited. This could definitely affect the quality of cement around the overlapped interval.

Once the job is completed, the setting tool and drillpipe are pulled out, leaving the cement to cure throughout the recommended WOC time. A checklist for running liners is published in API Bulletin D17 and is reproduced in the sidebar.

To reduce slurry contamination inside the liner, particularly when the liner is fairly long, a two-plug system called a dual liner wiper plug system or tandem liner-wiper plug system is preferred (Fig. 13-17). This system features two darts to launch their corresponding plugs. An inner string liner cementing process was proposed by Fuller et al. (1998) which, in addition to reducing contamination inside the liner during the cementing operation, also allows cleaning the liner after cementing and displacing the well before tripping out of the hole with the hanger setting assembly.

### Lining Running Procedures Checklist

The following procedure is taken from API Bulletin D17. The reader will note that it should be modified if the intent is to reciprocate or rotate the liner. The procedure is as follows.

1. Run drillpipe and circulate to condition hole for running liner. Temperature subs should be run on this trip if bottomhole circulating temperatures are not known. Drop hollow rabbit (drift) to check drillpipe ID for proper pumpdown plug clearance. On trip out of hole, accurately measure and isolate drillpipe to be used to run the liner. Tie off remaining drillpipe on the other side of the racking board.

2. Run __ ft of __ liner with float shoe and float collar spaced __ joints above float collar. Volume between float shoe and plug landing collar is __ bbl. Sandblast joints comprising the lower 1,000 ft and upper 1,000 ft of the liner. Run thread-locking compound on float equipment and bottom eight joints of liner. Pump through the bottom eight joints to be certain that float equipment is working.

3. Fill each 1,000 ft of the liner while running, if automatic fill-up type equipment is not used.

4. Install liner hanger and setting tool assembly. Fill dead space (if packoff bushing is used in lieu of liner setting cups) between liner setting tool and liner hanger assembly with inert gel to prevent solids from settling around the setting tool.

5. Run liner on __ size, type connection, weight, and grade drillpipe with __ pounds minimum overpull rating. Run in hole at 1 to 2 min per stand in casing and 2 to 3 min per stand in open hole. Circulate last joint to bottom with cement manifold installed. Shut down pump. Hang liner 5 ft off bottom. Release liner setting tool and leave 10,000 lbf of drillpipe weight on setting tool and liner top.

6. Circulate bottoms-up with __ bbl/min to achieve __ ft/min annular velocity (approximately equal to previous annular velocities during drilling operations).

7. Cement liner as follows: _________________.

8. If unable to continue circulation while cementing because of plugging or bridging in liner and hole wall annular area, pump on annulus between drillpipe and liner to maximum __ psi and attempt to remove bridge. Do not overpressure and fracture the formation. If unable to regain circulation, pull out of liner and reverse out any cement remaining in drillpipe.

9. Slow down pump rate just before pumpdown plug receives the wiper plug. Drillpipe capacity is __ bbl. Watch for plug shear indication, recalculate or correct cement displacement, and continue plug displacement plus __ bbl maximum overdisplacement.

10. If no indication of plug shear is apparent, plug calculated displacement volume plus __ bbl (100% + 1% to 3%).

11. Pull out 8 to 10 drillpipe stands or above top of cement, whichever is greatest. Hold pressure on top of cement to prevent gas migration until cement sets.

12. Trip out of hole.

13. Wait on cement __ hr.

14. Run __-in.-OD bit and fill cement to top of liner. Test liner overlap with differential test, if possible. Trip out of hole.

15. Run __-in.-OD bit or mill and drill out cement inside liner as necessary. Displace hole for further drilling. Spot perforating fluid (if in production liner) or other conditioning procedures as desired.

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*From Bowman and Sherer (1988). Reprinted with permission from World Oil.*
13-4.2.3 Planned squeeze

Long liners can be cemented in two stages when they traverse weak formations that would not withstand the hydrostatic pressure of the entire cement column. As illustrated in Fig. 13-20, the first stage is performed through the shoe using a limited, calculated amount of cement to cover the weak zone and place the cement top as close to the last casing shoe as possible, but not in the overlap. After the first stage is completed, the setting tool and drillpipe are pulled out of the hole and the cement is allowed to cure. Drillpipe with a standard squeeze packer is then run into the hole, and the packer is set two or three joints above the liner hanger. The second stage consists of squeezing a premixed amount of cement around the liner hanger. To be able to squeeze cement into the annular space, the formation fracture pressure in the openhole section must be overcome.

The advantages of the method are
- it avoids damaging weak productive formations
- uncontaminated cement is placed at the liner hanger
- no excess cement is necessary.

Disadvantages include
- the complete annular space around the liner in the overlap may not be cemented
- it may not be possible to inject anything (at safe pressures)
- the technique is more expensive.

With the advent of high-performance ultralow-density and foamed cement systems, this procedure is rarely performed.

13-4.2.4 WOC for liners

When long liners are set, there may be a considerable temperature difference between the bottom and the top of the liner. A slurry designed to have sufficient thickening time at the total depth may take longer to set at the liner top. A range of cement retarders (Nelson and Casabonne, 1992) allows the cement slurry to set and develop strength quickly, even when a large temperature difference exists between the circulating temperature and the static temperature at the liner top (Chapter 3). Drilling of cement must be performed after the cement develops the minimum compressive strength at the top of the liner to withstand the shock caused by drilling tools.

13-4.2.5 Tieback liners

There are situations when it may be necessary to extend an existing liner farther uphole, with a tieback "stub" liner, or to surface with a tieback casing string. For example, from a well-architecture and casing-design point of view, if a well must be cased from bottom to surface, it will be much easier and safer to run and cement the string as a liner first. Later, one can connect and eventually cement a tieback string. Other reasons for running tieback stub liners or tieback casings include
- covering up damaged casing above the top of an existing liner
- installing larger-diameter casing above the existing liner to allow for multiple production strings
- selective testing of multiple zones to design future production assemblies and the production casing size
- cementing troublesome intervals (e.g., high pressure, sloughing shales) before running the casing string to surface.

To accomplish this, special tools must be used to connect the two liner strings.

**Tieback sleeve**

Also called a tieback receptacle, polished-bore receptacle, or packer-bore receptacle, the tieback sleeve (Fig. 13-21) is either installed on top of the liner hanger or it comes as an integral part of the liner packer itself. The tieback sleeve provides a receptacle for the sealing nipple. Its internal surface is usually polished and beveled on the top to guide the entry of the different tools used during the operation.

**Tieback sealing nipple**

Run at the bottom of the tieback stub liner or casing, the tieback sealing nipple (Fig. 13-22) has multiple packing and sealing elements, which provide a seal against the polished surface of the tieback sleeve. The arrangements differ depending on pressure and temperature conditions and whether an additional metal-to-metal seal is required.

Tieback casings are usually cemented by conventionally circulating the slurries. The job is performed before landing the seal nipple into the tieback sleeve. However, the cementing may also be conducted with the tieback casing in place, using a stage collar above the sealing nipple.

![Fig. 13-21. Examples of tieback sleeves.](image1)

![Fig. 13-22. Different seal arrangements for the tieback sealing nipple.](image2)
Tieback liners must be cemented after their liner hangers have been set with the seal nipple landed into the sleeve (Fig. 13-23). A stage collar can be run on top of the seal nipple in the open position. The liner wiper plug must be able to land on the upper seal and close the collar ports.

Apart from the special procedures given above, the considerations applicable to all cement jobs also apply to tieback liner cementing. In most cases, hydrostatic pressures are not significant because cementing is performed between casings. The same care must be exercised with slurry designs and cementing procedures as for a regular primary cementing operation. A tieback casing is often a key design element for well integrity. The temperature difference between the bottom and top of the tieback string may be significant. Slurries must be stable at all downhole temperatures. Although lightweight slurries are more economical, normal-density slurries are preferred because they are much more efficient in terms of displacement mechanics.

The use of washes and spacers ahead of cement slurries will prevent mud and/or cement contamination and help to remove the mud from the annular space. This is especially important in tieback liner cementing, in which no bottom plug separates the mud from cement inside the liner. If there is completion fluid in the hole, compatibility with the cement must be checked or large volumes of fresh water must be pumped ahead of the slurry. Salts used in completion brines may drastically affect the cement slurry's thickening time, causing a premature set or delaying compressive strength development.

13-5 Special offshore techniques

As discussed in Chapter 12, the logistics of offshore cementing operations are often very different from those for land-based operations, but the cementing procedure employed on offshore drilling rigs (such as jackups) or platforms fixed to the seabed is similar to primary cementing operations on land. However, considerable differences exist in the plug release technique used on floating rigs.

Figure 13-24 illustrates the general arrangement of the subsea cementing system with respect to the subsea wellhead system.

13-5.1 Conventional subsea plug system

The subsea plug system is similar in operation to the liner plug system, apart from the larger size of the plugs. Except for the largest size, it consists of a top and bottom plug. The bottom plug is normally launched with a ball gravitating through the drillpipe to the seabed. Some recent models use a two-dart plug launching system instead of a ball and a dart. The technology developed for these subsea release plugs has been adapted to liner cementing as a single-plug system in 8⅝-in. [219-mm] liners and larger. Most of the models available today are top-drive compatible (Fig. 13-25).
Figure 13-24 illustrates a conventional subsea plug release system. It consists of a special subsea assembly in the casing below the casing hanger. The cementing head on the floating drilling vessel is made up to the drillpipe serving as the casing landing string and controls the cementing plug release. The head contains a launching ball and dart, while the subsea assembly contains the top and bottom casing plugs. Modern heads are top-drive compatible. Referring to Fig. 13-24, and by chronological order of usage, (b) is the bottom plug-launching ball, which, when released before pumping the cement slurry, seats in the bottom plug (e). A 100- to 275-psi [0.7- to 1.9-MPa] pressure increase allows the connector pins to be sheared (d), and permits the bottom plug (e) to travel down the casing until it bumps on the float collar and casing shoe.

Figure 13-25. Top-drive subsea cement heads.
Extra pump or hydrostatic pressure extrudes the ball (b) through its orifice seat, and cement displacement continues. A ball catcher attached to the lower end of the bottomhole plug retains the ball.

Once the cement slurry has been pumped, the topplug launching dart (a) is released. It will seat into the body of the top cement plug (c). Increased circulation pressure will then shear the retaining pins and release the top plug (c) from the launching mandrel. The cementing operation thus continues. At the end of the slurry displacement, the top plug (c) bumps on the float.

In the subsea assembly, before cementing, the top plug is pinned at the lower end of a running mandrel that has a swivel (g). This avoids any rotation of the cementing plugs inside the casing that could damage the shear pins. The upper part of the mandrel is made up to the lower part of the casing hanger running tool (h). This casing hanger running tool is a tool connecting the casing hanger to the drillpipe of the casing landing string. One of the major limitations, and often a source of cementing failure, is the reduced flow area through the plug-retaining mandrel. This restricted flow area is susceptible to fluid erosion and failure owing to high pump rates (often required for turbulent flow) and large fluid volumes of either mud or cement.

13-5.2 Innovative system for launching plugs with subsea wellheads

Brandt et al. (1998) introduced a two-plug launching system (Fig. 13-26) adapted to subsea operations from its original fixed installation concept (Lavaure and Galiana, 1991). This cementing head offers enhanced reliability because of a simpler cement-plug design in which the plugs are isolated in their container from the main fluid flow. Plugs are released from the subsea tool without physical contact between the darts and the plugs, avoiding dart-to-plug or ball-to-plug sealing problems.

13-5.2.1 Dart launcher

A surface dart launcher contains two identical darts launched during cementing. Darts are remotely released, reducing rig time and increasing the safety of the operation. Using darts instead of a free-fall ball helps prevent contamination, provides positive fluid displacement, wipes the drillpipe clean, and saves time. Uninterrupted high pump rates improve mud removal, because the fluid is neither resting nor allowed to gel at any time.

The darts release casing wiper plugs when they reach the subsea tool. Because the dart launcher is modular, adding segments is easy. This increases the number of darts that can be launched.

13-5.2.2 Subsea tool

After dart launch, mud flows down the drillpipe, through the sliding sleeve of the subsea tool, and out of the orifices. The dart lands on a rod, and continued pumping forces the dart and rod down, pushing the plug out of a basket. A spring retracts the sliding sleeve, allowing complete, unobstructed flow through orifices.

A pressure differential resists rapid rod motion and stops rod movement after the plug releases. Combined with plug friction, this pressure differential increases pumping pressure and provides a positive indication at the surface of plug launch. Physical spacers prevent the plugs from sticking and are retrieved with the tool.

The downhole subsea tool encases the plugs inside a container, eliminating difficulties associated with pumping fluids through the inside of plugs. Simplified plug design allows use of high-performance, but easily drillable, plugs.
The dart launcher has a high-pressure rating, and the plugs have a high collapse resistance; therefore, this system allows the operator to conduct a casing pressure test immediately upon bumping the plug. This saves rig time and reduces the risk of creating a microannulus or damaging the cement sheath—a danger when this operation is carried out at a later stage (Carré et al., 2002).

13-5.3 Deepwater cementing considerations

Other significant considerations in subsea cementing are hydrostatic pressure and temperature. The hydrostatic pressure of the seawater above the subsea assembly can be a significant factor. In addition, the temperature at the sea bottom and the first several hundred meters of hole must be considered (Ward et al., 2003). Frequently, the temperature is close to freezing at the ocean floor, and the underlying formation is substantially cooler than what is observed on land. This has implications for numerical simulations to predict the temperature profile during the cementing operation and laboratory testing to design cement systems appropriate to the conditions. Therefore, the International Organization for Standardization (ISO) (2003) and API (2004) issued special recommendations for testing cement systems for deepwater applications (Appendix B).

One of the major difficulties in drilling deepwater wells is the small pore- and fracture-pressure window. Enabling technology such as dual gradient drilling is emerging for deepwater and ultradeepwater wells. This method eliminates the excessive hydrostatic pressures caused by heavy mud and cuttings in the marine riser. The riser is filled with seawater; therefore, the subsea wellbore is exposed to the hydrostatic pressure of seawater. This technology is not only important from a drilling and well architecture point of view (Cuvillier et al., 2000), but the reduced hydrostatic pressure also reduces the risk of losses during the cementing operation. The Subsea Mudlift Drilling Joint Industry Project (Eggemeyer et al., 2001) developed the first dual-gradient drilling system in the industry. From a cementing perspective, this technology requires the use of a special float collar and, above all, a flow restrictor to limit any free fall of the heavy cement slurry (Schumacher et al., 2002). This technology has been successfully used in a well in 910 ft [277 m] of water, but more work is required to develop a system that can tolerate the severe free fall in wells drilled in 10,000 ft [3,048 m] or more of water.

Shallow water-producing formations compound the already difficult problem of cementing deepwater wells. For such situations, API issued Cementing Shallow Water Flow Zones in Deep Water Wells (RP 65, 2003), which gives a number of recommendations for managing the well and minimizing hazards before, during, and after the cement job. Apart from needing ideal mud displacement to remove the viscous kill fluid in the often enlarged holes, shallow water formations require a cement slurry that sets very quickly to prevent water migration into the annulus. When a low fracture gradient imposes the need for low-density slurry, foamed cement or high-performance lightweight cement provides the required level of performance (Cuvillier et al., 2000). A foam cement job on an offshore rig is more difficult, especially in remote areas or with difficult weather conditions. In these situations, a high-performance lightweight cement system is often preferred when adequate bulk storage is available. However, the two options should be weighted and compared on technical and economical merits for each local situation and for each well requirement, because both can be successful (Carré et al., 2002).

Deepwater development often requires extended-reach wells to minimize the number of subsea templates or to allow a dry tree development using a surface wellhead platform (tension-leg platform, deep-draft caisson vessel). In West Africa, for example, the departure of the longest extended-reach subsea well is about 8,200 ft [2,500 m] in the Girassol field in Angola (Anres, 2003). Extended-reach well technologies under development will allow subsea wells to reach between 26,000 and 30,000 ft [7,925 and 9,144 m] of departure (Anres et al., 2003). Such developments may require changes in the way casings are run and cemented.

13-6 Cementing techniques and new enablers

A number of emerging techniques enable the industry to drill more complex wells and produce hydrocarbons from the reservoir in a more efficient manner. This short section does not attempt reviewing and detailing them, but rather describes a few particulars regarding cementing operations in these special wells.

13-6.1 Extended-reach wells

Extended-reach wells are highly deviated wells with a high measured-depth (MD)/total-vertical-depth (TVD) ratio. Horizontal wells are a subset of extended-reach wells in which part of the wellbore is inclined 90° from vertical. With existing technology, the length of the
extended-reach section decreases with increasing TVD (Fig. 13-27). Well departures can be more than 33,000 ft [10 km] at vertical depths ranging from about 5,000 ft [1,500 m] in the United Kingdom, to about 5,250 ft [1,600 m] in Argentina, to about 7,200 ft [2,200 m] in Germany. Companies are working to push this limit beyond the 50,000 ft [15 km] mark.

Many applications exist in which extended-reach and horizontal wells can achieve production more economically than vertical wells:

- gas and water coning
- tight reservoirs and heavy oil
- fractured reservoirs
- edge-water or gas-drive reservoirs
- inaccessible reservoirs
- enhanced oil recovery
- reducing the number of platforms and wells needed to develop a field.

There are numerous technical challenges associated with extended-reach wells (Fig. 13-28). Hole cleaning (Cunha et al., 2002), hole stability, and running casing (Mason et al., 2003) are issues that strongly influence cementing. Mud removal is also a key issue during the cementing operation. Special centralizers that significantly reduce drag are used to help run the casing (Chapter 11). When the last cemented casing is not the production pipe, only a short section near the shoe is cemented to minimize the equivalent circulating density (ECD) and avoid losses. When long sections of the production casing must be cemented, more precautions are taken, and high-performance lightweight cements are used to achieve successful cementing of the entire section without losses (Frank et al., 1998).

Running the casing to bottom is the next important challenge in extended-reach wells (Mason, 2003). When the casing cannot be run to bottom by ordinary means like centralizers and mud lubricants, flotation is one of...
the simplest mechanical means to reduce effective drag and assist in running the casing (Mason et al., 1999). This imposes some rig modification as well as the use of a specific flotation sleeve and flotation collar, a sacrificial plug, and a three-plug cement head to minimize manual handling (Rae et al., 2004). Figure 13-29 shows the string configuration and position of fluids when the casing is landed and after bursting the flotation collar. After the sacrificial plug picks up the flotation sleeve and opens the flotation collar, mud circulation adjusts mud properties, because the well could not be circulated until this moment. Then the cementing operation is performed normally, often with high-performance lightweight cements because the pressure-operating window is narrow in such long horizontal wells.

13-6.2 Solid expandable tubulars

Solid expandable tubulars were first tried as a contingency measure to allow drilling to proceed through problematic zones (heavy losses or unstable formations) without having to set an intermediate drilling liner. This technology prevents the loss of one casing diameter. Today, the technology has matured sufficiently to allow well architects to plan and engineer cost-effective wells. Demong and Rivenbark (2003) and Demong et al. (2004) showed that this technology could be successfully applied in extended-reach wells, allowing the operator to significantly reduce the torque and drag without losing casing size.

Fig. 13-29. Landing the casing and bursting the flotation collar in extended-reach wells (from Rae et al., 2004). MDRT means measured depth below rotary table. Reprinted with permission of SPE.
Campo et al. (2003) realized the ultimate goal for which solid expandable tubulars were invented: they successfully completed the first monobore well. This resulted in significant savings compared to conventional wells or even slim wells for the same production-casing size. Figure 13-30 compares the monobore architecture with that of conventional and slim wells.

Figure 13-31 details the installation process for a solid expandable tube and shows the cementing operation. With the tube on bottom before inflation, the cement slurry is pumped down the drillpipe and up the annulus like a normal inner-string cementing operation. The slurry volume corresponds to the annular volume of the inflated tube. One must ensure that the top of cement after inflation is below the overlap; otherwise, the expansion and sealing of the hanger may be affected. After mixing the slurry, the latch-down plug is dropped. When it reaches and latches onto the launcher, increasing pressure initiates the expansion process. The liner is then expanded from the bottom up in stages of one stand at a time. The cement slurry must remain stable and fully liquid until the expansion process is completed; otherwise, the expansion may be impaired by gelled slurry or by solids deposits from settled or dehydrated slurry. The entire expansion may require several hours, as much as 10 hr for long liners, after which the slurry should set and develop strength quickly.

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**Fig. 13-30.** Monobore well with conventional and slim-well plans (from Campo et al., 2003). SET means solid expandable tubular; FJ means flush joint; and MDDL means monodiameter drill liner. Reprinted with permission of SPE.
13-6.3 Multilaterals

Multilaterals are multiple wellbores (or multiple horizontal wells) that emanate from a single wellbore (Economides et al., 1998). They were invented in the 1920s and installed in Russia in the 1950s. However, it was not until the 1990s that interest in this technique became widespread and the technology was accepted by the industry for effective reservoir management. A joint industry project of North Sea operators, called Technology Advancement for Multilaterals (TAML) (Diggins, 1997), classified multilateral wells in six different categories (Chambers, 1998; MacKenzie and Hogg, 1999) depending on the mechanical integrity and pressure integrity required at the junction. The junction is defined as the point at which two separate wellbores merge. As seen in Fig. 13-32, the TAML classification ranges from Level 1, with an openhole sidetrack or unsupported junction, to Level 6, which includes both reformable and nonreformable splitters to provide pressure integrity. Level 5 provides pressure integrity with the downhole completion equipment. Levels 3 to 6 provide mechanical strength at the junction.

The junctions in Levels 2 to 5 are in fact laterals sidetracked from the cased and cemented mother wellbore. Then a completion with varying levels of complexity assures mechanical or pressure integrity at the junction. With respect to the mother wellbore, one must ensure that the cement sheath is resilient enough to resist the shocks incurred while the junction window is milled out. If the cement around the junction is brittle, it may fracture in chunks or blocks. Such blocks may fail at the wrong time, increasing the risk of an expensive bottomhole assembly (BHA) or completion string becoming stuck. Figure 13-33 shows the result of milling a window with conventional cement and a special cement system toughened by adding fibers (Chapter 7).

Fiber cements have very good impact resistance and good postfailure behavior. However, such systems are expensive and, if a small volume is used, placing it exactly at the right place may prove difficult. On the other hand, flexible systems (Chapter 7) are more affordable. They are highly elastic, deform easily without cracking, and have relatively good shock resistance. Latex-modified cements (Chapter 7) also provide

![Fig. 13-31. Installation sequence of a solid expandable tubular (from Demong and Rivenbark, 2003). Reprinted with permission of SPE.](image-url)
increased flexural and tensile strength and have found application in cementing some multilateral wells.

However, in a multilateral Level 4 system, when the liner hanger of the lateral bore is drilled out after cementing to leave the main bore entirely free, only tough and resilient cement can provide the adequate mechanical support without failing.

Throughout the industry, the emphasis is now shifting from providing an open, unsupported Level 1 junction in competent, consolidated formations to high-end Level 5 and 6 systems that offer full hydraulic and mechanical junction integrity (MacKenzie and Hogg, 1999). Even for the Level 6 system, in which pressure integrity does not by design depend on the cement job quality at the junction.

Fig. 13-32. Classification of multilaterals (from Moritis, 2003). Reprinted with permission from *Oil & Gas Journal.*

Fig. 13-33. Cement sheaths after milling junction window in a multilateral well.
(Hogg, 2002), it still seems preferable to use a small volume of tougher cement around a short junction at the bottom of the motherbore. This would ensure that the formed-metal structure of the splitter remains fully supported at all times when drilling and completing the two legs. Then pressure integrity at the junction can be assured. Therefore, all the different types of multilateral wells benefit from having an advanced tough cement around the junction.

13-6.4 Casing drilling

The concept of screwing a bit on a joint of casing, then drilling into the ground and cementing through the bit has been around for more than 100 years. It started in Russia at the beginning of the twentieth century. In the 1950s and 1960s, this technique was also used in the United States. However, the technique did not become widespread, because it was more suitable for one-trip applications. Therefore, it was limited to softer formations, relatively shallow wells (as in the mining industry), and wells in which there were no openhole evaluation requirements.

The industry tried for many years to develop effective retrievable systems but it is only in the last few years that mechanically reliable, retrievable drilling systems appeared on the market. Casing drilling could therefore be rejuvenated (Tessari and Madell, 1999) as a technique to eliminate the use of drillpipe, significantly reduce tripping times, and reduce lost time caused by unscheduled events such as reaming, fishing, and taking kicks while tripping. At about the same time, significant progress was made with a drillshoe system attached to the end of the casing. Although casing drilling technology is still in its infancy, experience so far has demonstrated that standard oilfield casing can be used to simultaneously drill and case the well.

Casing drilling is performed by attaching the bit to the bottom of the casing or through a BHA that extends beyond the casing. Bit rotation originates from rotating the casing string using the topdrive or by using downhole motors. The latter method employs wireline-retrievable BHAs so that bits or BHAs can be changed without tripping the casing (Fig. 13-34).

Surprisingly, casing drilling can reduce some lost-circulation problems. It appears that the casing drilling process consolidates and strengthens the wellbore by plastering the cuttings into the borehole walls.

The occurrence of stuck pipe, long a major drilling problem, is also relatively rare during casing drilling (Fontenot et al., 2003). When it does occur, the casing is cemented in place and drilling can continue with the next size; however, prematurely giving up a casing size may have a negative impact on production, because the ultimate size of the production casing or tubing may be smaller than planned. In some cases, that limitation is not acceptable. During drilling with a shoe, the stuck casing is cemented in place as usual though the drilling shoe. However, during drilling with a retrievable system, the BHA must first be recovered on wireline if it is not stuck. The use of casing drilling technology is expanding to directional wells (Warren et al., 2003) and deepwater wells (Galloway, 2003).

Cementing during a casing drilling operation differs slightly from conventional cementing. First, from a cement-slurry placement point of view, the casing is poorly centralized because only hard-facing wear bands and sometimes solid hydroformed centralizers are used. Both are crimped onto the casing. For a production casing string, when the string is drilled to total depth with a conventional bit attached to the bottom of the casing, stabilizers are sometimes used near the bottom to provide a stiffening effect and maintain verticality. The stabilizers are not designed for cementing centralization, so the rest of the casing string is not centralized.

Wear bands and stabilizers are solid and do not have any restoring force. They are sufficient to prevent the casing from touching the borehole walls and being worn out during the drilling operation. For cementing purposes, this is likely to be sufficient in a gauge hole, but
may become problematic and largely inadequate for casing centralization in a washed-out hole. This imposes constraints on the cement slurry, which must efficiently remove the drilling fluid at pressures below the fracture gradient. Diaz et al. (2004) showed that friction losses and the equivalent circulating density can be fairly well estimated; therefore, flow rates, rheologies, and fluid densities can be adjusted to minimize the annular friction pressures and avoid losses during cementing.

Although a few directional wells have been drilled with casing drilling technology, most of the experience today is with vertical or near-vertical wellbore sections, in which the casing is not centralized as discussed above. Little information is available regarding cementing operations in directional wells drilled with casing.

The cementing procedure differs with the type of bit installed on the casing.

- If the bit is attached to the casing, a special casing-drilling bit (Fig. 13-35), derived from an expandable drill bit (Brown and Gledhill, 2003), drills like a conventional polycrystalline diamond compact (PDC) bit. At casing depth, a pressure cycle displaces the PDC cutters into the borehole wall or extrudes them to a greater diameter than the next hole section, opening the bottom of the casing. The casing is then cemented normally, but this technique does not allow rotation or reciprocation. Following the cement job, the rest of the bit assembly can be drilled out with a conventional PDC bit.

- After casing has been drilled to its setting depth, using a retrievable bit assembly that can incorporate measurement while drilling and logging while drilling tools, it is normally first pulled out by wireline (Warren et al., 2000). However, in this situation, the casing does not have a float collar to land the cement plug. To overcome this problem, special bottom and top wiper plugs (Tessari and Madell, 1999) were designed; however, this equipment was not sufficiently robust. Today, a pump-down float (Vert and Angman, 2001) is pumped in place before the cement injection (Warren et al., 2000). A pressure increase confirms that the float has correctly landed in its profile nipple. An alternative solution (Skinazi et al., 2000) provides a single cement top wiper plug that locks into its landing collar (Fig. 13-36). The cementing operation can now proceed conventionally, and the casing can be rotated and reciprocated. In operations in which a poor bond was obtained conventionally, casing rotation greatly improved zonal isolation in subsequent operations.

![Fig. 13-35. Expandable bit for casing drilling (from Brown and Gledhill, 2003); reprinted with permission of SPE.](image)

![Fig. 13-36. Example of cement wiper plug and lock collar used in casing drilling operation (Skinazi et al., 2000). Reprinted with permission of SPE.](image)
If a pumpdown cement float or a locking cement plug is not available for the casing size used, then the casing is cemented through a composite retainer run on drillpipe (Warren et al., 2001a and 2001b). Floats and retainers can also be run on wireline. As a contingency measure, the cement slurry can also be placed volumetrically, a common approach on surface casing strings. However, this should be the last resort, because fluid intermixing and bypassing inside the larger casing will occur.

During the drilling of the last string in the well with casing, a knock-off sub is commonly used to drop the bit before performing any other cementing or completion operation.

### 13-7 Operational considerations

Planning is basic to successful primary cementing. It begins with accurate knowledge of the well conditions. The cement job is designed for these conditions, and job parameters must be monitored and recorded during job execution. Later, the actual job can be compared to the design.

#### 13-7.1 Calculations

##### 13-7.1.1 Slurry volume

Because of the difficulty of gauging large open holes, surface casing hole volumes are rarely known. The volume of cement slurry must be based on common field practice in the area. If this is not known, excess slurry volumes of 50% to 100% should be used. Excess slurry volumes of up to 200% are common in some areas; the volumes may exceed 300% for the top sections of some deepwater operations.

Even when a caliper is run and the theoretical volume is calculated, an excess volume is often required to ensure proper fill-up. As much as 50% in excess of the calipered hole volume may be used. In many countries, the volumes of slurries are governed by regulations that can be very stringent (Chapter 12).

##### 13-7.1.2 Displacement

The displacement fluid pushes the cement slurries out of the casing to fill up the annulus and isolate the respective horizons. It is important to achieve complete displacement not only to ensure that correct fill-up and isolation are achieved in the annulus, but also to avoid wasting time drilling out excess cement left in the casing. In addition, incomplete displacement eliminates the ability to pressure test the casing. Displacement ends when the top plug lands on the float collar, an event commonly known as bumping the plug. During some cementing operations, the plug does not bump after pumping the theoretical casing displacement volume. Under these circumstances, to avoid leaving a wet shoe (shoe surrounded by unset cement), an additional volume corresponding to half the shoe track volume is often pumped before stopping the operation. However, in most cases, a significant volume of cement is found above the float collar.

The displacement volume is normally calculated according to the nominal casing capacity for its size and weight. However, casing manufacturers do not make casing for a fixed internal diameter. Casing specifications include mechanical properties, outside diameters, wall thicknesses, and drift diameters, but not the internal diameters. Not accounting for the true casing diameter is the principal cause of not bumping the plug. For example, the internal displacement volume of 9,843 ft [3,000 m] of a 9 5/8-in., 47-lbm/ft casing is 720.5 bbl [114.6 m³]. This volume would be 735 bbl [116.9 m³] if the internal diameter is 1% larger than the nominal value. This difference exceeds 12.6 bbl [2 m³], and a two-joint shoe track has a capacity of 6.3 bbl [1 m³]. Therefore, to avoid such costly errors, some operators have adopted a policy to systematically gauge either all the casing joints or a statistically significant number of joints in the string.

A second cause of displacement-volume errors is failing to account for the compressibility of the displacement fluid, especially when using oil-base muds. Although pressure and temperature work in opposite directions, the displacement-volume error can be significant (several barrels). Drilling fluid companies can provide the compressibilities of their muds, allowing the operator to calculate the correct volumes to be safely pumped to achieve bumping the plug.

#### 13-7.2 Hole condition

In addition to the physical hole parameters (i.e., depth, diameter and direction), the drilling reports should be reviewed to identify potential problems that could affect the cement job. Hole washouts, lost circulation, and tight spots should be noted and addressed in the design. A caliper log should be mandatory on most jobs. When a caliper cannot be run, pumping a marker (such as a carbide pill) while drilling is always a good practice to assess the degree of washout before cementing. Drilling mud types and properties have a significant effect on the state of the borehole wall and the quantity of cuttings left downhole. This necessitates conditioning the hole before the cement job and influences the performance of the cement slurry. Drilling muds are
designed to drill the hole efficiently, but the mud engineer rarely considers the cement job. Therefore, after drilling, the mud properties must be optimized to satisfy cementing requirements. Proper practices must also be implemented to ensure that the modified mud effectively displaces gelled mud left over from the drilling process.

13-7.3 Temperature

Knowledge of the bottomhole circulating temperature (BHCT) is vital. The cement-slurry pumping time is a direct function of the bottomhole temperature. Overly long slurry pumping times can be as disastrous to primary cementing as those that are too short. Temperature also affects the cement and mud characteristics; consequently, the flow regimes, U-tubing effect, and friction pressures are all directly affected (Chapters 4, 5, and 12). If the BHCT is unknown, it can be determined through logging, circulating temperature probes (Jones, 1986), or mathematical simulation of cementing circulating temperature (Beirute, 1991; Mitchell and Wedelich, 1989). Temperature simulators (Guillot et al., 1993) have been introduced and validated (Merlo et al., 1994; Davies et al., 1994) with field measurements on land wells. Romero and Touboul (1998) further extended the capabilities of temperature simulators to deepwater operations, which were validated with field measurements (Ward et al., 2003).

When strength development time is a key parameter, it is equally important to know the time required for the cement-slurry temperature to reach the static temperature. Only temperature simulators can provide such information, which is used by laboratory personnel to test the performance of the cement systems under realistic conditions. Deepwater wells particularly benefit from this capability.

When dry cement is added to water, the subsequent hydration generates heat that raises the temperature of the cement slurry. The cement-slurry temperature also depends on the temperature of the dry cement and the mix water. The nomograph shown in Fig. 13-37 has been used for many years to estimate the cement-slurry temperature during mixing. Today, this nomograph is incorporated in cement-slurry design software applications.

The initial cement-slurry temperature can have a significant effect on the bottomhole circulating temperature during a cement job. If a job is performed in a hot or cold climate and the cement and mix-water temperatures differ significantly from 80°F [27°C], prejob laboratory testing should reflect these conditions. Jestes et al. (2003) presented a case study that illustrates the...

**Fig. 13-37.** Nomograph to estimate cement-slurry mixing temperature.
importance of the cement and mix-water temperatures on slurry performance. If these temperatures are not taken into account, WOC times may be too long in the winter and too short in the summer. The performance of cement additives, particularly accelerators, can vary widely with temperature.

13-7.4 Pressure
Accurate knowledge of downhole pressure is necessary for well control and successful primary cementing. A minimum slurry density is required for well control during and after placement, and slurry rheology governs the friction losses during placement. Excessive slurry density together with a high displacement rate can lead to fractured formations and lost circulation; when lost circulation is feared, the ECD in the annulus must be projected at the design stage. A typical intermediate casing string cement job, with its minimum and maximum hydrostatic pressures, is shown in Fig. 13-38. This type of plot should be generated for all primary cement jobs (Chapter 12).

Well control is also of concern after displacing the cement slurry, especially while WOC. On stationary rigs (land, jackups) using conventional wellheads, it is extremely important to WOC before lifting the BOPs for slips and packoff installation.

13-7.5 Quality control
A quality control program should be employed to test all materials before cementing. Laboratory conditions should simulate the job as closely as possible from known well conditions. Actual field samples of cement, additives, and mix water should be used for testing.

Because ISO and API specifications for cements are necessarily broad in scope, additional testing should be performed whenever the cement quality is suspect. ISO and API rheology tests may help to identify potential problems. Liquid additives should also be checked and thoroughly blended with the mix water before cementing. Certain dry additives are prone to separation (particularly weighting agents), and care should be taken to verify proper blending with the dry cement exists before the job (Gerke et al., 1990).

13-7.6 Casing movement
Casing movement—reciprocation, rotation, or both—positively improves the quality of primary cement jobs (Fig. 13-39). Casing movement breaks up areas of stagnant mud, which can cause cement channeling. Scratchers and wipers are of little benefit, unless they are put to work by casing movement.

Fig. 13-38. Pressure plot for intermediate casing cement job.
Casing that cannot be moved before cementing confirms that something is wrong. Often, not much can be done at this point other than to cement the casing in place; however, the chances of a successful cement job are diminished before even mixing the slurry.

Some operators prohibit the use of reciprocation when cementing from a floating rig, for fear of the casing getting stuck protruding above the subsea wellhead. Also, it should be noted that reciprocating is particularly difficult, not to say impossible, in deviated wells.

Although it can be easily accomplished on almost every drilling project, casing rotation is in fact seldom performed because of either wellhead design or other equipment or rig limitation. From the very beginning, the overall well design and equipment selection should aim towards making casing movement possible. When conventional casings are being cemented, the highest torque load is generally reached when the lead end of the cement reaches the shoe. Therefore, the casing connection strength requirement must be calculated to consider this load, not just the drilling load.

13-7.7 Cement job monitoring

The recording of critical parameters during cementing, from the commencement of mixing cement to the final displacement, is paramount. Pressure, slurry rate, density, and integrated volume are factors that must be known in real time. These data should also be recorded for future playback and analysis to evaluate and optimize the design of future jobs (Piot and Loizzo, 1998). Recording devices also verify that the correct volumes and densities of preflushes, spacers, and cement slurry were pumped into the well. Before cementing takes place, it is particularly important to ensure that the pressure-monitoring equipment is functioning correctly. A typical recording device output is shown in Fig. 13-40.

The sensor package is equally important. For pressure, accurate and fast-responding electronic transducers have replaced traditional hydraulic gauges. It is important to monitor and record the pressure until the top plug is bumped. Slurry densities and flow rates are accurately recorded with Coriolis mass-flow vibrating tube devices (Benabdellkarim and Galiana, 1991; Chapter 11). Such devices have largely replaced traditional radioactive densitometers.

Traditionally, pressure, rate, and density are recorded during a cement job. In 2003, Vigneaux et al. introduced a cement monitoring and control system based on the slurry volumetric balance. The slurry quality is guaranteed by assuring that it contains the designed quantity of cementitious solids, regardless of the slurry density. Although originally engineered for high-performance, low-density cements, this monitoring system (which records several other process parameters) offers improved accuracy at all slurry densities and for all types of cement slurries.

13-7.8 Casing operational sequence

13-7.8.1 Stationary rig (e.g., land rig, jackup rig)

When the conductor pipe has been driven to the desired depth (or cemented), a mud return line or flowline is installed underneath the rig floor so that drilling fluid can return to the pits. The hole is then drilled to the depth required for the surface casing. After the casing has been run and cemented (always to surface), it is cut off underneath the rig floor at the desired height. The casing head (which will enable the next size of casing to be hung and connects to the BOPs) is then welded to the surface casing, inside and outside. Some casing heads screw onto a casing thread.

The BOPs, with the connections for the kill line and choke line, are flanged onto the casing head. Before drilling can continue, the BOPs must be tested to the
desired pressure. A sealing plug is run into the casing on drillpipe, and the BOPs are closed one by one. The BOP elements are pressure tested one after the other. All BOPs and wellhead connections must hold pressure before drilling can continue (Fig. 13-41). Then, when the next size of hole has been drilled to the desired depth, the next size of casing is run in and cemented. Cement may or may not be required to reach the surface.

The cement is usually allowed to set while the casing is hanging from the elevators. After it has set and while the casing is still hung from the elevators, the BOPs are lifted from the casing head and suspended from the sub-structure. Slips and the packoff assembly are then set between the casing and the casing head.

To avoid buckling of the casing downhole, it is very important that the casing be set with the same weight hanging from the slips as that hanging from the elevator. The casing can then be cut off at the same level as the

Fig. 13-41. Connection of casing strings.
casing-head flange, or 1 or 2 ft higher. A sealing mechanism is normally placed above the slips to seal the annulus between the two casing strings. Then, a new casing head is flanged to the previous head, the BOPs are reattached (or replaced by BOPs with a higher pressure rating), and (after pressure testing the connection) drilling can recommence. This entire process is known as nipping up.

In this way, each time a new string of casing is run, it is hung from a casing head that was attached to the previous casing head. The production casing will have a head from which to hang the tubing—the tubing head. Therefore, the weight of all the strings is partly supported by the surface casing (Fig. 13-42).

13.7.8.2 Floating rig (e.g., semisubmersible, drillship)

On a floating rig, the wellhead and the BOPs are at the seabed. In some ways, the sequence is simpler than on a stationary rig because the BOPs are not removed each time a casing is run and cemented.

The surface casing is run and connected to the top of the wellhead housing. The subsea BOPs are then run and connected to the wellhead housing by a hydraulic connector. Drilling can continue after pressure testing of the wellhead-BOP system.

Each intermediate casing and the production casing are similarly run and cemented. They are connected to the top of a casing hanger, which lands in the wellhead housing, and an annular seal assembly is installed to seal the annulus. The successive casing hangers pile up on top of each other.

13-8 Conclusion

The basic mechanics of common primary cementing techniques have been presented in this chapter. When decoupled from the other related issues, such as fluid rheology, cement-slurry design, cement-slurry mixing procedures, and annular gas migration, these procedures may appear to be very simple. Such an impression is deceptive. It is essential that the engineer be intimately familiar with the procedures and devices that are used for primary cementing. In addition, it is critical that the engineer verify that all equipment is in proper working order before the job; otherwise, the long and meticulous planning process before each job may be wasted.
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<td>API</td>
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<td>Bottomhole assembly</td>
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<td>OD</td>
<td>Outside diameter</td>
</tr>
<tr>
<td>TAML</td>
<td>Technology advancement for multilaterals</td>
</tr>
<tr>
<td>TVD</td>
<td>True vertical depth</td>
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<tr>
<td>WOC</td>
<td>Waiting on cement</td>
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14-1 Introduction

Remedial cementing is a general term to describe operations that employ cementitious fluids to cure a variety of well problems. Such problems may occur at any time during the life of the well, from well construction to well stimulation, production, and abandonment. Remedial cementing is commonly divided into two broad categories: plug cementing and squeeze cementing. Plug cementing consists of placing cement slurry in a wellbore and allowing it to set. Squeeze cementing consists of forcing cement slurry through holes, splits, or fissures in the casing/wellbore annular space. This chapter describes each category and provides fundamental procedures and practices.

During well construction, remedial operations may be required to maintain wellbore integrity during drilling, to cure drilling problems, or to repair defective primary cement jobs. Wellbore integrity may be compromised when drilling through mechanically weak formations, leading to hole enlargement. Cement slurries can be used to seal and consolidate the borehole walls. Remedial cementing is often the only way to repair defective primary cement jobs, to either allow further drilling to proceed or to provide adequate zonal isolation for efficient well production. Lost circulation is another serious drilling problem that can be cured with cement slurries. Such applications are described in Chapter 6.

During well production, remedial cementing operations may be performed to restore production, change production characteristics (to alter the gas/oil ratio [GOR] or control water production), or repair corroded tubulars. During a stimulation treatment, the treatment fluids must enter the target zones and not leak behind the casing (Chapter 1). If poor zonal isolation behind the production casing is suspected, a remedial cementing treatment may be necessary.

Finally, well abandonment frequently involves placing cement plugs to ensure long-term isolation between geological formations, replicating the previous natural barriers between zones. However, before a well can be abandoned, annular leaks must be sealed. Squeeze cementing techniques are applied for this purpose.

Each candidate for remedial cementing presents a unique challenge to the engineer; therefore, to address the variety of problems that may occur, a wide range of techniques has been developed combining placement methods, specific slurry formulations, and execution procedures. Successful remedial cementing requires careful analysis of the downhole problem(s), meticulous planning to formulate the best solution, and proper job execution (Jones and Watters, 1998).

A wide variety of cement slurries has been developed to address almost any type of problem. Unless special formulations are used, the following points must be noted.

- Cement is an intrinsically brittle material, so it will have less resistance to mechanical stresses than purely mechanical solutions.
- Cement slurries are suspensions, so they have at best small penetration into narrow gaps and can repair only near-wellbore problems.

These limitations can be overcome by using alternative solids-free remedial techniques; thus, remedial cementing techniques are not the only solution to many of these well problems. A few of these techniques will be briefly discussed at the end of the chapter.

This chapter has the following organization. A preliminary section presents the types of well problems that can be cured by remedial cementing. To avoid confusion, detailed discussion of remedial cementing operations and techniques is kept to a minimum. Thorough discussions of plug- and squeeze-cementing operations and techniques are then presented separately.

14-1.1 Overview of remedial cementing operations

Plug cementing consists of placing an amount of cement slurry in a wellbore and allowing it to set. The plug may be temporary or permanent, and it may be placed in an open hole or a cased section.

Squeeze cementing is the process of forcing a cement slurry under pressure through holes, splits, or fissures in the casing/wellbore annular space. When the slurry is forced against a permeable formation, the solid particles filter out onto the formation face as the aqueous phase (cement filtrate) enters the formation matrix. The slurry is pumped until the wellbore pressure reaches a prede-
An impermeable filtercake, not the setting of cement, allows the well to withstand this increased pressure. When highly permeable media are present, such as gravel packs, the entire cement slurry may invade the porous medium. A properly designed squeeze job causes the resulting cement filtercake to fill the opening(s) between the formation and the casing. Upon curing, the cake forms a nearly impenetrable solid (Suman and Ellis, 1977). In cases in which the slurry is placed into a fractured interval, the cement solids must bridge the fracture and then develop a filtercake on the fracture face.

The execution of a remedial cementing operation begins by preparing the well. In particular, if the cement slurry must be placed off-bottom and there is a risk for the slurry to fall under gravity down the well, a plug is placed to serve as a cement base. The plug may be a viscous or reactive fluid (sometimes weighted to a density halfway between that of the wellbore fluid and the cement slurry) or a mechanical device (Fig. 14-1a).

The cement slurry is then prepared at the surface and pumped through drillpipe or coiled tubing to fill the wellbore. The tubular is usually pulled back out of the cement slurry. On rare occasions, the pipe is left in the cement (Fig. 14-1b). Before setting, the cement plug may be slightly squeezed into the formation, but most of the cement remains in the hole.

During squeeze cementing treatments, most of the cement slurry is forced into the formation or behind the casing (Fig. 14-1c). Excess slurry that did not enter the formation may be removed from the wellbore. This is the cleaning phase, often performed by reverse circulation (Fig. 14-1d). There are many variations on this general theme that are specifically tailored to the operational objectives, available equipment, and local practice.

14-1.2 Methodology
The selection and implementation of a specific remedial operation follows a logical series of steps.

Problem identification
This step may be either obvious (e.g., holes in casing detected following a corrosion log) or difficult to detect (e.g., identification of a gas leak resulting in sustained casing pressure). The importance of this step is often overlooked.

Selection of remedial method
Once the root cause of the problem is identified, selection of the appropriate solution is easier. Often, several radically different techniques are potentially applicable. Both economic and technical factors are considered.

Figure 14-1. Principal steps of a remedial cementing operation (refer to text for a detailed description).
**Selection of placement method and mechanical setup**

The simplicity of the operation is balanced with potential risks.

**Selection of fluid volumes**

At this stage, more detailed information about well properties is required. Sometimes different scenarios may be prepared, and the treatment choice is deferred until just before the job, based on last-minute well data.

**Detailed job design**

In this step, the job is simulated to verify that all well-safety issues are considered. Alternative treatment designs are formulated as a contingency in case the treatment does not go as expected.

**Execution**

Execution requires close monitoring of pressure and rate data, as well as comparison with design data. Significant discrepancies may result in pumping-schedule changes.

**Evaluation**

The evaluation of job success is based on comparing the actual results with the initial job objectives. This step is especially important to improve future jobs in nearby wells.

### 14-2 Problem identification—Well problems cured by remedial cementing

A wide variety of problems may be faced during the life of a well. Although the type of problem is often easy to determine, identifying its root causes may be difficult.

Very often, only a good knowledge of the root causes can ensure that the selected remedial treatment will have an acceptable chance of success. In this section, the common types of problems are presented along with a short description of the appropriate remedial treatments. Table 14-1 provides a concise summary.

#### 14-2.1 Well construction

During well construction (i.e., drilling, casing, cementing, and completion), a drilling rig is available on location. This allows one to consider all of the standard methods for curing the problem.

##### 14-2.1.1 Lost circulation

Lost circulation is considered in detail in Chapter 6. Lost-circulation problems are detected by comparing mud return rates with pump rates or by monitoring the fluid level in the mud tanks. When adding chemicals, lost-circulation materials (LCMs), or fibers during drilling is unsuccessful, various types of cement plugs can be placed and slightly squeezed to ensure good adhesion between the cement and the formation. Once the cement has set, drilling can resume.

Two key questions must be answered before the job.

- What is the nature of the leak: permeable formation, natural fissures, induced fractures, caverns?
- At which depths are the loss zones located?

Natural fractures and caverns are more common in carbonate rocks. Permeable zones are encountered more frequently in sandstones. The depth is measured by correlating drilling reports with electrical imaging logs.

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<table>
<thead>
<tr>
<th>Table 14-1. Principal Activities that Can Be Accomplished by Plug Cementing and Squeeze Cementing</th>
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<tbody>
<tr>
<td><strong>Plug Cementing</strong></td>
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<tr>
<td>Seal lost-circulation zones</td>
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<tr>
<td>Sidetrack around a <em>fish</em> (lost object or other debris in the hole)</td>
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<tr>
<td>Initiate directional drilling</td>
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<tr>
<td>Seal a depleted zone</td>
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<tr>
<td>Protect a low-pressure zone during a workover treatment</td>
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<tr>
<td>Provide an anchor for openhole tests</td>
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<tr>
<td>Seal wells for abandonment</td>
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An appropriate cement slurry is then set across the lost-circulation (or “thief”) zone. Although some of the slurry may be lost to the thief zone, it will harden and consolidate the formation (Fig. 14-2). A cement plug can also be set above a zone to protect it from being fractured by the hydrostatic pressure developed while cementing a casing string. LCMs are often added to the plug slurry to maximize the chance for success (Chapter 6). Cements containing fibers have also been used. The fibers not only form a “mat” to inhibit loss of cement slurry to the formation, but also prevent cement fragments from falling on the bottomhole assembly (BHA) (van Vliet et al., 1995). The combination of fibers and cements with optimized particle-size distributions has produced acceptable solutions in difficult situations (Elmoniem et al., 2000). In the extreme case, when the wellbore offers no support (e.g., for caves or caverns), inflatable cement bags have been proposed (Piot et al., 1994).

Many alternatives to cement plugs are available to control lost circulation, such as deep-penetrating fluids that plug fissures and fractures (Chapter 6). Such materials are beyond the scope of this discussion.

One of the factors that helps kicking off is to make the compressive strength of the plug greater than that of the formation or to increase the toughness of the plug. The usual compressive-strength requirement for a kickoff plug is 5,000 to 7,000 psi [35 to 49 MPa]. If it is not possible to prepare a cement system with a higher compressive strength than the formation, the toughness of the plug can be increased by reinforcing the cement matrix with materials such as polymer fibers (Loveland and Bond, 1996) or metallic microribbons (Al-Suwaldi et al., 2001; Chapter 3). However, Trabelsi and Al-Samarrai (1999) raised concerns about potential degradation of some cement properties (porosity, permeability, and compressive strength) when fibers are added. Other factors that determine the chances of kicking off relate to the BHA used, the well deviation and the drilling direction.
14-2.1.3 Protective plugs

In addition to repairing defects, temporary cement plugs are used to protect a weak zone at the bottom of a well while performing high-pressure operations in upper zones. Cement plugs are used when the hole is not cased; otherwise, mechanical bridge plugs are a better solution. The cement plug is called a test anchor (Fig. 14-4).

![Fig. 14-4. Plug set as an anchor for a test.](image)

14-2.1.4 Well construction evaluation

After a section has been cased and cemented, the cement quality is checked before drilling is resumed. The most common evaluation technique is the pressure test. The pressure test involves pumping a fluid into the wellbore to exert pressure, closing the well, and monitoring the wellbore pressure. A pressure decline indicates the presence of a leak that must be plugged. More advanced cement evaluation methods include cement logs that are run only when good zonal isolation and casing mechanical support must be demonstrated. The occurrence of such defects has decreased as better cementing practices have been implemented. In exceptional cases, some flow may be observed at the surface, which is a clear signature of poor zonal isolation. Evaluation techniques are presented in detail in Chapter 15.

If a problem has been detected, the root causes must be investigated. Common causes include the following.
- Poor mud displacement
- Poor knowledge of the well before cementing (e.g., hole geometry)
- Cement-placement problems such as lost circulation

Poor mud displacement during primary cementing causes the cement slurry to channel through the drilling mud or a mud film to remain on the walls. Consequently, pockets or channels of mud are left behind the casing (Fig. 14-5), and the principal goal of primary cementing—zonal isolation—is not achieved. Should such zonal-isolation defects not be corrected, serious problems may occur during the life of the well.
- Stimulation treatments may not achieve the expected results because of poor fluids-placement control (Chapter 1).
- Evaluation of a well’s production potential may be inaccurate because of the parasitic effects of nearby flowing fluids.
- Poor well productivity may occur as a result of a high WOR or GOR.
- Enhanced oil recovery techniques such as waterflooding may fail (Goolsby, 1969).

![Figure 14-5. A defective primary cementing job.](image)

The principal tool for diagnosing the root cause is a careful comparison of the job record with design and evaluation data. Once the root cause is known, a variety of cement-based repair treatments may be performed.
- Squeeze the shoe
- Liner top squeeze
- Perforate and squeeze mud channels
Circulation squeeze
Block squeeze
Perforate and fill the annulus in a manner similar to a two-stage cementing operation

E lecting to perforate a cemented casing and perform a squeeze job is a difficult decision. Any procedure that might compromise casing integrity or further harm zonal isolation should not be taken lightly. Defining precisely where to perforate is also critical. A thorough analysis of the primary cementing job, based on an accurate record of all the parameters of the operation and a careful interpretation of the logs (Chapter 15), is a key element in the decision process. Two situations may exist behind the casing.

- The mud channel sits against a permeable formation. During the squeeze job, the cement filtercake builds and eventually fills the void.
- Circulation is established between two sets of perforations. A “circulation” or “channel” squeeze is performed to replace the mud in the channel with cement. Basically, this is a partial or total recementing of the interval of interest. It is important to note that this procedure can be precarious. The risks and possible unwanted consequences are explained later in this chapter.

Both of these operations can be successful only if the downhole treating pressure remains below the formation fracturing pressure. If not, fractures created during the job would open a preferential route through which a large quantity of the cement slurry can penetrate; as a result, damage to the permeable interval will occur; and the treatment objectives will not be met.

14-2.1.5 Circulating squeeze

The circulating squeeze, illustrated in Fig. 14-6, is often performed with a cement retainer in preference to a packer (Chapter 11). Circulation is achieved with water or acid as a preliminary fluid. The interval is circulated with a wash fluid to ensure good cleanup, and the cement slurry is then pumped and displaced. No pressure buildup occurs during the job, except for an increase caused by the hydrostatic pressure of the cement column as it flows up the annulus. Once the placement is completed, the stinger or packer is released. The excess cement circulating out of the upper perforations can be reversed out if desired.

The volume of slurry required to complete a circulating squeeze is unknown; therefore, plenty of slurry is prepared. Consequently, there is a strong possibility that some of the cement slurry may enter the casing, drillpipe, or tubing or the annulus above the squeeze tool during the job. Should this cement set, the drillpipe (or tubing) may become stuck in the hole. Therefore, to minimize this risk, a cement retainer should be run instead of a packer. It is easier to remove the stinger assembly than the packer, because the latter has minimal casing clearance. The retainer should be set as close as possible to the upper perforations. This minimizes exposure of the drillpipe to cement slurry that may enter the wellbore through the upper perforations.

14-2.1.6 Block squeeze

Block squeezing is a method to prevent fluid migration from either above or below a producing zone in which the bond log indicates poor zonal isolation. The permeable section below the producing zone is perforated and squeezed. The procedure is then repeated for the permeable zone above the producing zone. The two plugs of residual squeeze cement are then drilled out, and the productive zone is perforated for production. This method has frequently been successful in preventing water coning.

14-2.1.7 Top of liner squeeze

As discussed in Chapter 13, liner cementing can be difficult because of the small annular clearance and often poor centralization. The amount of cement used during primary liner cementing is small, and the wellbore geometry is often not conducive to good mud removal;
consequently, mud contamination can occur. In addition, annular fluid migration can be a complicating factor (Chapter 9).

If the liner leaks at the overlap, the remedial procedure is the same as squeezing a hole in the casing. If good coverage is not obtained, the casing must be perforated and another squeeze job performed (Smith, 1987).

14-2.2 Production/injection
Several types of problems may occur during the life of a well that require remedial cementing operations, linked either to poor zonal isolation behind casing or changes in the nature of the production.

14-2.2.1 Before stimulation treatments
During a stimulation treatment, the treatment fluids must enter the target zones and not leak behind the casing. If poor zonal isolation behind the production casing is suspected, a remedial cementing treatment is necessary. As detailed above, the most common method to assess zonal isolation is the cement bond log.

14-2.2.2 Sustained casing pressure
A producing well that displays casing pressure on the surface suffers from a lack of zonal isolation. In such cases, gas often migrates to the surface. Eventually, remedial treatments will be required.

Xu and Wojtanowicz (2001) described a method to assess the severity of the problem, based on a pressure test. Once the problem has been assessed, noise logs are used to find the leak and specifically the depth at which the gas enters. Noise is generated by fluid flowing through narrow channels within the cement sheath (McKinley and Bower, 1979). The depth at which noise is observed corresponds to the producing-zone location.

The carbon-isotope method is a more recent technique to locate the depth of a leaking gas zone. The method is based on the recognition that, for shallow gas reservoirs, the origin of the gas may be thermogenic or biogenic. The relative amount of biogenic gas decreases with increasing depth, and the isotopic composition is variable. The isotopic composition of thermogenic gas is not.

Thus, the $^{13}$C/$^{12}$C ratio of various components of a gas (mainly ethane) can be correlated with the reservoir depth. This calibration must be performed for each reservoir. The current calibration method is to perform an isotopic analysis of gas in drilling fluid as hole depth increases. The carbon isotope technique was developed at the University of Alberta (Rich et al., 1995; Ellis et al., 2003) and has been used in Canada and the Gulf of Mexico. The technique is currently limited to shallow-gas reservoirs and must be considered a complement to other information sources.

14-2.2.3 Casing and packer leaks
Producing wells may suffer from corrosion caused by brines or acid gases that migrate from the formation to the tubulars. Leaks will eventually appear in the production tubing or casing (Figs. 14-7 and 14-8). Leaks may also appear at packers. In all cases, crossflows, production of unwanted fluids, or loss of production to other zones may result.

![Fig. 14-7. Three-dimensional image of a hole in casing.](image-url)
Under these circumstances, cement plugs are frequently more successful than squeeze cementing (Nowak et al., 1996; Loveland and Bond, 1996). Old and corroded casing may suffer further damage when subjected to the high treating pressures and packer-generated stresses associated with squeeze cementing. Casing leaks have also been seen on new pipes, in which case a patching job can be performed.

14-2.2.4 Production and injection control

The GOR or WOR may not meet expectations for many reasons, including errors when perforating the reservoir and reservoir depletion. Determining the root cause of excessive water production is beyond the scope of this chapter; however, methods are available to help identify the problem (Bailey et al., 2000). The most common problems include a moving oil/water contact (Fig. 14-9), crossflow, bypass through fractures or high-permeability streaks, and water coning.

Like production control, water-injection or steam-injection profiles can be durably controlled by remedial cementing methods, provided no crossflow occurs between the zones.

Methods available to identify the root causes of these production problems include various logging or injection methods.

- Temperature logs (Bergren and Bradley, 1988)
  Temperature logs follow wellbore temperature variations as a cold fluid is injected through the perforations and can indicate whether channels exist in the cement behind the casing. This procedure is also called a pump-in temperature log. Correlating temperature logs with cement logs allows a full assessment of the presence of channels in the cement.

- Boron-pulsed neutron log (Blount et al., 1991; Sommer and Jenkins, 1993)
  The procedure is similar to the pump-in temperature log. A boron solution is injected through the perforations, and a pulsed neutron log is generated. Boron absorbs neutrons very efficiently; consequently, channels in the cement sheath can be readily detected, even through two strings of casing. The method is more sensitive than the pump-in temperature log.
Oxygen activation logs (Pappas et al., 1995)
Oxygen activation logs are used to quantify water flow behind casing. The logging tool uses the high-energy neutron generator to send large quantities of neutrons around the wellbore and the formation. The neutrons cause the oxygen nuclei to produce a radioactive isotope of nitrogen with a 7-sec half-life. As the nitrogen decays, high-energy gamma rays are emitted. If there is water movement past the tool, each gamma ray detector will detect the decay at two different times. The two times are converted to a fluid velocity. By using more detectors or changing their spacing, the range of measurable velocities can be adapted. A significant benefit of this technology is that fluid movement can be detected and measured without direct contact with the logging tool. For example, it is possible to detect water flow behind tubing or nonperforated casing.

Production logs (Kuchuk and Sengul, 1999; Lenn et al., 1996; Caretta et al., 2000)
Water/oil contacts and other formation heterogeneities can be detected by production logs either during production or shut-in periods. Such information can help identify water entry points along producing intervals.

Injectivity test
An injectivity test consists of pumping a fluid into the formation and analyzing the pressure response. This type of test is especially useful to help characterize water-control problems or to determine whether there is a void space behind the casing.

Production history
If there has been any sand production or dissolution of the formation, there is a chance that void spaces exist behind the casing.

Only a limited number of production problems can be reliably cured by remedial cementing methods. Some root causes, and the remedial-cementing techniques employed to cure them, are listed below.

- Breakthrough through a well-identified layer, with no crossflow:
  The remedial treatment involves plugging the perforations or part of a gravel pack in front of the problem zone.

- Communication behind casing:
  The channel is plugged by performing a low-pressure or circulation squeeze.

- Natural fissures or fractures and void space behind casing:
  A squeeze treatment is performed with the goal of filling the void with cement.

- Induced fractures or channels:
  Treatments other than remedial cementing are often better suited for these types of problems. Nevertheless, squeeze treatments are frequently employed.

- Production depletion:
  When production from a zone falls below a commercially viable level and other zones exist uphole that can produce economically, a cement plug can be placed across the depleted zone to isolate it from the wellbore (Fig. 14-10).
Well abandonment:
To abandon a well, several cement plugs are set at various depths, often using coiled tubing. This procedure prevents interzonal communication and fluid migration that might pollute underground freshwater sources (Fig. 14-11). In many countries, oil and gas well operators are compelled to follow abandonment procedures dictated by government authorities (e.g., Texas Railroad Commission Rule 3.14: Plugging, 2002; Barclay et al., 2001; Nagelhout et al., 2005). The ultimate objective of these remedial treatments is to restore the natural integrity of the formation that was disrupted by drilling. The resulting hydraulic isolation is expected to last for several decades.

14-3 Plug cementing—Tools and techniques
There are several tools and techniques for placing cement plugs:
- balanced plug
- dump bailer
- two-plug method
- mechanically supported method (with jet-hole cleaning)
- flexible bags
- inflatable through-tubing packers
- umbrella-shaped membranes
- coiled tubing placement.
Cement slurries are almost never pumped through drillbits. Doing so could damage the bit bearings. Consequently, placing cement plugs consumes rig time because it requires several drillstring trips. Cement slurries used in plug cementing must not display sedimentation or free water, and the thickening time must be sufficiently long to allow thorough cleaning of the drillstring after placement.

14-3.1 Balanced plug
The most common placement method is the balanced-plug technique (Fig. 14-12). Tubing or drillpipe is run into the hole to the desired depth for the plug base. To avoid mud contamination, appropriate volumes of spacer or chemical wash are pumped ahead of and behind the cement slurry. The volumes are such that they correspond to the same heights in the annulus and in the pipe. The slurry is often batch mixed for better control of density and rheology. Basic calculations used to design balanced plugs are presented in Appendix C.

It is common practice to slightly underdisplace the plug (usually by 2–3 bbl). This practice avoids mud flowback on the rig floor after placement and allows the plug to reach a hydrostatic balance. Once the plug is balanced, the pipe is slowly pulled out of the cement to a depth above the plug, and excess cement is reversed out. One variation of this process involves placing the cement slurry in two steps—as two balanced plugs, one on top of the other.

The main problem that may arise during the placement of a balanced plug is cement contamination. To minimize downward migration of the cement plug, fluids with high gel strengths can be placed as a base. Examples of such fluids include thixotropic bentonite suspensions or crosslinked polymer pills. These pills may be weighted to ensure better stability of the cement lower interface by avoiding instabilities caused by fluid density differences. Mechanical devices are also commonly employed (Section 14-4.2.1).

14-3.2 Dump bailer
A dump bailer is a vessel that holds a measured quantity of cement slurry. Lowered on a cable, the dump bailer opens when it touches a permanent bridge plug placed below the desired plug interval (Chapter 11, Section 14-4.2.1). The cement slurry is dumped on the plug by raising the bailer (Fig. 14-13). Usually employed for setting plugs at shallow depths, the dump-bailer method can also be used at greater depths if the cement slurry is properly retarded. The advantages of this method are that the depth of the cement plug is easily controlled and it is relatively inexpensive. The principal disadvantage is that the quantity of cement slurry is limited to the volume of the dump bailer; however, multiple runs can be made.
To help meet the plug objectives, the dump-bailer method must incorporate hole and mud conditioning. The bailer should be raised slowly for proper placement. Because the slurry is stationary during its descent, special slurry-design considerations are required, especially under high-temperature conditions. Slurry gelation or instability must be avoided to ensure that the slurry will exit the dump bailer.

14-3.3 Two-plug method
The two-plug method uses a special tool to set a cement plug at a calculated depth, with a maximum of accuracy and a minimum of cement contamination. The tool essentially consists of a bottomhole sub installed at the lower end of the drillpipe, an aluminum tailpipe, a bottom wiper plug (which carries a dart), and a top wiper plug (Fig. 14-14). Foam balls may also be used in the place of wiper darts.

The procedure includes the following steps.
1. The bottom plug is pumped ahead of the cement slurry to clean the drillpipe wall and isolate the cement from the mud.
2. The shear pin connecting the dart to the plug is broken by increased pump pressure and pumped down through the aluminum tailpipe.
3. The top plug is pumped behind the cement slurry to prevent contamination from the displacement fluid. Increased surface pressure is observed when the plug arrives at its seat.
4. The drillpipe is pulled up until the lower end of the tailpipe reaches the calculated depth for the top of the cement plug.
5. The shear pin between the catcher sub body and the sleeve is then broken, allowing the sleeve to slide down and open the reverse circulating path. If the aluminum tailpipe becomes stuck in cement, an increase in the pull will break the tailpipe and free the drillpipe.
6. Excess cement is then circulated from the hole.

14-3.4 Inflatable packers
Use of inflatable packers is an adaptation of the balanced-plug method (Heathman et al., 1994; Jones and Watters, 1998) and employs an inflatable-set packer to provide a solid bottom (Chapter 11). The packer assembly includes a diverter tool that circulates fluid and washes the wellbore as the tool is run into the hole. A drillable aluminum tailpipe is installed above the packer to the required plug height.

When the tool reaches the target location, the inflatable packer is filled with cement slurry and expands to form a mechanical support. Then the ports in the tailpipe are opened and the cement slurry is placed in the same manner as a balanced plug. The tailpipe is then disconnected and left in the plug.

More recently, this technique has been adapted to allow packer installation and inflation with coiled tubing (Wilson et al., 2004). In addition, packers have been designed to withstand extreme temperatures and pressures as well as harsh chemical environments.

14-3.5 Umbrella-shaped membranes
Harestad et al. (1996) developed an umbrella-shaped tool that is deployed below the cement plug to aid the placement of balanced plugs. After deployment, the tool keeps the cement slurry separated from the drilling fluid below (Fig. 14-15). It must be emphasized that the tool is not a hydraulic barrier and cannot be used to control losses farther down the well.
Arebrat (2004) described another tool—a diaphragm bow—that is pumped like a cement plug through a drillpipe and expands when it exits (Fig. 14-15). This tool is designed to prevent both fluid mixing during placement and fluid swapping.

14-3.6 Inside blowout preventer

An internal, or inside, blowout preventer (IBOP) is sometimes inserted in the drillpipe near the rig floor when the drillpipe is pulled above the cement plug (Fig. 14-16). The IBOP is run to avoid flowback in situations when, owing to a small density differential, it is difficult to balance the plug. The IBOP is activated from the surface. In terms of design, it has no specific impact except preventing backflow. Today this tool is mainly used in the U.S. Gulf of Mexico.

14-3.7 Coiled tubing placement

Use of coiled tubing for remedial cementing began in the early 1980s. Since then, the technique has gained considerable popularity (Walker et al., 1992; Loveland and Bond, 1996). Coiled tubing has proved to be a very economical method to accurately place the small volumes of cement slurry required in plug cementing operations. Harrison and Blount (1986) reported that, in some instances, up to 85% savings on workover costs can be achieved when using coiled tubing. Coiled tubing is also used extensively for squeeze cementing. It is discussed later in this chapter.

14-4 Plug cementing—Placement

To ensure the cement plug fulfills its objectives, several placement issues must be considered.

- Place the plug at the correct location.
- Prevent cement contamination.
- Ensure sufficient thickening time at downhole temperature to complete the placement and well cleanup.
- Ensure that pressure and mechanical-strength limits are not exceeded during all stages.

14-4.1 Plug location

Placement of abandonment plugs is often controlled by government regulations. The key objective is to restore the natural isolation between geological layers that was
destroyed when the well was drilled. The natural location to place a plug is at the same depth as the caprock. Kelm and Faul (1999) reviewed the best practices in this domain.

Lost-circulation plugs should be placed wherever loss zones are encountered (Lindstrom et al., 1999). Whiptstock or kickoff plugs should not be positioned against excessively hard formations.

14-4.2 Contamination

Contamination during plug cementing has long been recognized as a serious problem, and sets of preventive guidelines have been proposed (Dees and Spradlin, 1982; Heathman et al., 1994). The primary consequences of cement contamination are a dramatic setting-time change and deterioration of mechanical properties. Table 14-2 shows a situation in which the setting time increased with water-base mud contamination. The situation is more complex with emulsion muds. If the emulsion remains stable, serious retardation may result. If the internal aqueous phase contains calcium chloride and the emulsion breaks, acceleration may occur.

Contamination of cement plugs may occur at different times and for different reasons.

- During placement, inside the drillpipe, at the front and rear interfaces of the cement slurry
- Unstable base or top, owing to density differences (heavy fluid on top of a lighter fluid)
- During placement with drillpipe (downward flow at the drillpipe tip can cause mixing of the cement slurry with other wellbore fluids)
- Washed-out zones (mud removal is difficult, and the wellbore volume may be underestimated)

Table 14-2. Effect of Mud Contamination on Cement Performance

<table>
<thead>
<tr>
<th>Mud Contamination (% by volume)</th>
<th>Neat Class H Cement (16.5 lbm/gal)</th>
<th>Compressive Strength in 18 hr at 230°F</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Compressive Strength (psi at 170°F)</td>
<td>8 hr</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Normal Slurry 15.0 lbm/gal (psi)</td>
</tr>
<tr>
<td>0</td>
<td>4,650</td>
<td>5,860</td>
</tr>
<tr>
<td>5</td>
<td>3,500</td>
<td>5,300</td>
</tr>
<tr>
<td>10</td>
<td>2,600</td>
<td>4,540</td>
</tr>
<tr>
<td>20</td>
<td>2,400</td>
<td>2,330</td>
</tr>
<tr>
<td>50</td>
<td>245</td>
<td>471</td>
</tr>
</tbody>
</table>

1 Contains dispersant.

- Contamination caused by overdisplacement
- Failure to adhere to mud removal guidelines (cement may be contaminated by a mud channel or by a mud layer not being displaced from the walls)
- While pulling the pipe out
- Reversing out the excess cement

Each of these scenarios is covered in the following discussion.

14-4.2.1 Mechanical devices to prevent or minimize contamination

There are several mechanical devices that can address some of the causes of cement contamination mentioned above.

Bridge plugs

When a cement plug is placed off-bottom, a bridge plug (Fig. 14-17) can be used to prevent the heavy cement slurry from falling through the less dense fluid underneath. To prevent the releasing mechanism from being cemented, most operators drop one or two sacks of sand on top of the retrievable bridge plug before the job. Calcium carbonate is also sometimes placed on top of the plug, followed by a sand cap. The calcium carbonate can be removed by acid to facilitate packer retrieval.

Drillable bridge plugs are normally used to isolate the casing below the zone to be treated. Their design is similar to that of cement retainers (Chapter 11). They can be run with a wireline or with the workstring. Bridge plugs do not allow flow through the tool.
Tailpipe or stinger

The drillpipe is equipped with a stinger or tailpipe (i.e., a few joints of smaller-diameter pipe). This reduces contamination when the drillpipe is pulled out, because the fluid volumes involved are smaller. The stinger may be made of aluminum or fiberglass pipe and may be left in the cement plug to provide additional reinforcement while the cement sets. In the latter case, once the cement is set, the tailpipe is broken at its top by increasing tension or with explosives. This method is sometimes used in horizontal wells, reducing the tendency of the cement slurry to slump (Fig. 14-18). Van Vliet et al. (1995) presented cases in which a glass-fiber-reinforced epoxy pipe was left in the middle of a temporary cement plug to ease the plug removal process.

Diverter tool

As cement slurry exits the pipe, a downward jetting action may occur that may break or contaminate the viscous gel that serves as the plug base. To prevent downward flow, the tip of the pipe can be equipped with a diverter tool (combination nozzle) (Fig. 14-19). The tool redirects the flow in an outward or radial direction. There are many tool designs available for both drillpipe and coiled tubing (Krause, 1991; Walker et al., 1992).

Mechanical plugs, darts, and balls

Various types of mechanical plugs, darts, and balls have been used to provide a barrier between fluids as they flow downhole. These devices may eventually be used to accurately indicate the positions of interfaces and prevent overdisplacement. They are an integral part of the two-plug placement method described earlier in Section 14-3.3.

14-4.2.2 Interface stability

Cement plugs placed off-bottom have a natural tendency to be unstable, because the density of the cement slurry is greater than the fluid underneath (Fig. 14-20).

Beirute (1978) was the first to clearly recognize this instability. Since then, extensive laboratory experiments have been performed to study the phenomenon (Smith et al., 1983; Calvert et al., 1995; Heathman, 1996), and
some correlations have been found, including the effect of density differential, yield stress, hole size, and deviation. Although the principle of the instability is easy to understand, its physical modeling is more difficult.

Beirute (1978) presented the first analytical model for a perfectly vertical well. This basic model was further developed and numerically solved by Griffin and Valkó (1997). Crawshaw and Frigaard (1999) presented a more general solution that is valid for inclined wells, showing that the heavy fluid slumps along the borehole wall and leads to a flow exchange between the cement slurry and the underlying mud. From a theoretical analysis varying well deviation, hole size, and density differential, they determined the minimum yield stresses required to prevent the flow exchange. Wamba Fosso et al. (2000) used these predictions in field operations and found the success rate to be close to 100%.

The relevant dimensionless groups that describe the process are

\[ \tau_{mud} = \frac{(\tau_y)_mud}{\Delta\rho g d_{hole}} \quad \text{and} \quad \tau_{cem} = \frac{(\tau_y)_{cem}}{\Delta\rho g d_{hole}}, \]

in which \((\tau_y)_{mud}\) and \((\tau_y)_{cem}\) are the yield stresses of the mud and cement, respectively. \(\Delta\rho\) is the density difference, \(g\) is the acceleration of gravity, and \(d_{hole}\) is the hole diameter. The stability limit is shown in Fig. 14-21. Any condition located on the upper right side of the plot corresponds to a stable situation. It appears that the predictions are conservative with respect to the experiments by a factor of approximately two.

Different types of viscous pills have been used to prepare a base for the plug, including bentonite suspensions, silicate gels, and crosslinked polymer solutions. A shear-sensitive plugging fluid has been used in difficult situations (Lindstrom et al., 1999). Reactive solutions have also been applied to form a strong gel upon contact with the cement slurry.

14-4.2.3 Displacement volume for a balanced plug

When placing a balanced plug, overdisplacement of the cement slurry may lead to severe contamination. To avoid overdisplacement, one must have an accurate measurement of the displacement volume.

An ideal example of balanced plug placement is given below.

- A drillpipe is lowered to the planned cement-plug bottom. The drillpipe has well-defined inside and outside diameters, and the hole is gauge and filled with a known mud.
- A spacer fluid, a cement slurry, and a spacer fluid are displaced by the same mud that is in the hole.
- The volumes of the two spacer stages are such that their respective heights in the annulus and pipe are
equal. The volume of displacement mud is exactly equal to the internal volume of the drillpipe up to surface.

- Once all the fluids are pumped, the drillpipe is slowly pulled out.
- As the drillpipe is pulled out, the fluid interfaces fall. When the pipe end reaches the cement-spacer interface, no mixing between the spacer and the cement occurs because the interfaces in both the annulus and the pipe are at the same depth.

In actual operations, there are many factors that lead to uncertainties regarding the displacement volume.

- The diameter of the pipe is not uniform when a stinger is used.
- If the plug is placed in an openhole section, its diameter will not be uniform.
- Often the only way to monitor the volume of mud pumped is to count the number of pump strokes; unfortunately, the pump efficiency is rarely known. When possible, it is better to directly monitor the fluid level in a calibrated tank.
- The internal pipe volume is frequently unknown, because the pipe may be worn or covered with a layer of set cement. The nominal pipe diameter also varies within a given range. For example, an internal-diameter variation of 0.1 in. corresponds to a volumetric variation of about 1 bbl per 1,000 ft. Varying the displacement volume by this amount could significantly change the location of the fluid interfaces.

- The fluids are compressible, and their volumes will decrease as they are pressurized. It is often assumed that thermal expansion compensates for compressibility; however, this assumption is far from exact, particularly when oil-base muds are involved.
- Balanced plug design is particularly difficult in situations in which there is lost circulation. The well conditions are uncertain and the hole may only be partially filled.

Considering these uncertainties, it is usually preferable to underdisplace the cement rather than risk overdisplacement.

Software programs are available to simulate these effects and determine the optimal displacement volume (Fig. 14-22). Appendix C also presents the equations for manual calculation. Treatment designs performed with foamed cement require special computational methods (Kulakovsky and Creel, 1992).

Another way to eliminate the risk of overdisplacement is to use mechanical plugs. When they land on a downhole collar, a positive pressure change is observed at the surface.

![Diagram](image)

**Fig. 14-22.** Example of under-displacement for cement plug placed with a tailpipe. Left diagram: fluids position at the end of pumping. Right plot: movement of the various fluid interfaces while the pipe is pulled out.
14-4.2.4 Inadequate mud removal
An accepted rule is to limit the plug length to about 1,000 ft (300 m) to minimize contamination. Longer plugs can be set provided special attention is paid to controlling gel-strength development and ensuring excellent mud removal. If the wellbore is deviated, the risk of contamination is higher because the plug slides downhole as the drillpipe is removed. It is preferable to place several shorter plugs on top of each other, even if the cost is higher.

To prevent contamination in the annulus, rotating or reciprocating the pipe during placement is essential. A diverter tool also helps to displace gelled mud and mud-cake deposited on the borehole wall. Minimizing pipe eccentricity and combining pipe movement and efficient jetting through the diverter provide the best possible mud removal.

14-4.2.5 Pipe removal and reversing out
While pulling the pipe out, cement contamination can be prevented by using a stinger and reducing the pull-out speed. This is especially important in highly deviated sections where gravity forces are not helpful. One solution is to leave the stinger in the cement during setting and to cut it afterwards.

When reversing out excess cement slurry, the pipe bottom should be moved at least 100 ft above the top of cement to prevent its destabilization. This is discussed in the following section.

14-4.3 Cleanup
Excess cement is cleaned out by either direct or reverse circulation. Cleanup is performed when the actual hole volume is uncertain and a large excess of cement has been used to ensure that the top of cement lies at the correct depth. A cleanup operation is also required to ensure that no cement remains in the drillstring.

Direct circulation involves pulling the pipe above the desired top of cement and circulating a contaminating fluid. Cleanup in reverse circulation consists of pumping the contaminating fluid down the annulus so that the excess cement slurry goes up the pipe. Each method has advantages and disadvantages.

- The time required to circulate out a given volume of fluid is much shorter when reverse circulating. The thickening time of the slurry can be designed to be shorter for a reverse circulation cleanup.
- When performing reverse circulation, the smaller hydraulic diameter of the pipe compared to the annulus can lead to higher bottomhole pressures. If lost circulation is a potential problem, direct circulation should be selected.

If coiled tubing is being used, the excess cement is also contaminated and circulated out (refer to Section 14-15).

Typical contaminating fluids include borax solutions with bentonite and biopolymer solutions. The aims are to delay the thickening time sufficiently to allow removal of the cement slurry and to prevent solids sedimentation in the contaminated slurry. When the drillstring is used to inject the contaminant, the volume is limited by the length of a pipe stand. In such cases, reverse circulation may be preferred. In all cases, the cement plug itself must not be disturbed. To eliminate this risk, some operators prefer to allow the excess cement to set and then drill it out.

14-4.4 Pressure and mechanical-strength constraints
Three basic safety constraints must be checked at all times during the various stages of the operation, including cement placement and cleanout.

- The dynamic fluid pressure in front of the formation must be less than the formation fracturing pressure.
- To prevent formation-fluid entry, the static fluid pressure in front of the formation must be higher than the pore pressure.
- The differential pressure across the various tubulars must be less than their burst or collapse pressures. When working with coiled tubing, the weight of tubing filled with cement must remain within its tensile-strength limits. One must also account for fatigue of the coiled tubing.

Software that predicts fluid pressures is readily available, even for foamed fluids (Bour et al., 1990).

14-5 Plug cementing—Cement-slurry design
Cement-slurry design is covered elsewhere in this textbook (Chapters 3, 7, and 12). However, there are a few slurry-design guidelines related to plug cementing that deserve to be mentioned here (Jones and Watters, 1998).

In general, the thickening time should be adequate for placement, but strength should develop rapidly. Slurry sedimentation or free water must be scrupulously avoided. If weak formations are present, the slurry density should be the minimum necessary to obtain the desired ultimate strength; otherwise, a dense slurry can be beneficial. To preserve the integrity of the plug, the set cement must not shrink.
When the goal of the plug is well abandonment, the set cement must have low permeability—preferably less than 0.001 mD. If the plug is set in an open hole, the slurry should have adequate fluid-loss control.

For directional drilling and whipstock plugs, the set cement should be stronger than the surrounding formation. If this is not possible, adding toughening agents such as metal fibers can be useful (Chapter 3).

For lost-circulation plugs, low-density or thixotropic cement systems can be effective. Adding particulate LCMs or fibers is also beneficial.

Frequently a remedial cement system must be resistant to subsequent well stimulation treatments. The requirement is usually expressed in terms of solubility in HF-HCl acid systems. Latex cement slurries and epoxy-base synthetic cements are especially resistant to these conditions. Combining low cement permeability with small-particle-size cement and latex also provides enhanced acid resistance (Heathman et al., 1993).

Chemical resistance to wellbore fluids—brines and hydrocarbons—is required for long-term durability of abandonment plugs. Bosma et al. (1998) suggested using a silicone-based material. For high-temperature applications, special systems have been developed that provide good durability in the presence of brines (Chapter 10).

Adequate bonding of the set cement to the casing is required to ensure durable isolation. The bonding may be compromised by radial casing movement following the high mechanical stresses exerted during production operations or negative-pressure tests. The shear strength of the bond between the set cement and casing must also be sufficient to withstand high differential pressures. The bond strength of cement with steel is usually assumed to be a small fraction of the cement compressive strength (Chapter 6). The bond strength can be increased by using expansive cement systems (Vijn and Fraboulet, 2001) or nonshrinking materials such as silicone-cement composites (Bosma et al., 1998).

**14-6 Cement-plug evaluation**

After the waiting-on-cement (WOC) time has elapsed, the job results are evaluated. For cement plugs this process is fairly straightforward.

- The quality of a whipstock or kickoff plug is tested while attempting to kick off.
- The efficiency of a lost-circulation plug is evaluated by comparing the loss rates before and after the treatment.
- A well abandonment plug is tested for imperviousness by monitoring the fluid level in the well.
- The depth of the top of the plug can be determined by tagging the cement after the WOC time has elapsed.

If the job objective has not been attained or the problem has not been satisfactorily repaired, the reasons for failure should be carefully investigated. Design modifications and improvements can then be made to improve the probability of success during subsequent treatments.

As discussed earlier, the most common causes of failure are linked to cement contamination or insufficient cement volume. For a cement plug placed off bottom, contamination is likely caused by an unstable bottom interface. A cement plug placed in a washed-out zone is more likely to fail because mud removal is difficult and the wellbore volume may be underestimated. Finally, if mud removal guidelines have not been followed, the cement may be contaminated by a mud channel, by mud left on the borehole wall, or while pulling out the pipe.

**14-7 Squeeze cementing—Introduction**

As mentioned earlier, squeeze cementing has many applications.

- Repairing a primary cement job that has failed because of mud channeling or insufficient cement height in the annulus
- Eliminating water intrusion from above, below, or within the hydrocarbon-producing zone
- Reducing the producing GOR or WOR by isolating the gas or water zones from adjacent oil intervals
- Repairing casing leaks caused by corroded or split pipe
- Abandoning a nonproductive or depleted zone
- Plugging one or more zones in a multizone injection well to direct the injection into the desired intervals
- Sealing lost-circulation zones
- Protecting against fluid migration into a producing zone

In the following sections, a review of perforation plugging theory, tools, placement techniques, slurry design, job design, and job monitoring is presented. Finally, job evaluation and reasons for failures are discussed.
### 14-8 Squeeze cementing—Perforation plugging theory

During most squeeze cementing treatments, the particles in the cement slurry are too large to enter the formation matrix. As a result, an external cement filtercake accumulates, fills the perforations, and forms nodes that protrude into the wellbore (Figs. 14-23 and 14-24).

When a volume of slurry, \( V_{\text{slurry}} \), containing a solid-volume fraction, \( f_{\text{slurry}} \), is forced against a porous medium, a liquid filtrate of volume \( V_{\text{filt}} \) passes into the medium. The solids that remain behind produce a filtercake of porosity \( \phi \). Mathematically, this is written as follows.

**Solids volume fraction:**

\[
 f_{\text{slurry}} = \frac{V_{\text{solids}}}{V_{\text{slurry}}} \quad (14-2)
\]

**Conservation of volumes:**

\[
 V_{\text{slurry}} = V_{\text{filt}} + V_{\text{fc}} \quad (14-3)
\]

where

\( V_{\text{fc}} = \) filtercake volume.

Cake porosity:

\[
 V_{\text{fc}} = (\phi \times V_{\text{fc}}) + V_{\text{solids}} \quad (14-4)
\]

Inserting Eq. 14-2 and 14-3 into Eq. 14-4, one obtains

\[
 V_{\text{fc}} = \frac{f_{\text{slurry}}}{1 - f_{\text{slurry}} - \phi} V_{\text{filt}} = wV_{\text{filt}} \quad (14-5)
\]

The factor

\[
 \frac{f_{\text{slurry}}}{1 - f_{\text{slurry}} - \phi}
\]

is called the deposition factor, \( w \). It corresponds to the ratio of the filtercake volume to the filtrate volume and can be measured by a standard American Petroleum Institute (API) or International Organization for Standardization (ISO) fluid-loss test. Experimentally, one observes that this factor is almost constant when the differential pressure is varied, indicating that cement filtercakes are incompressible. A neat 15.8-lbm/gal [1,900-kg/m³] cement slurry has a solids volume fraction of 40%. The porosity of cement filtercakes from this system is usually about 30%. Thus, a typical value for the deposition factor is about 1.3.

To determine the time required to build a filtercake of given height \( h_{\text{fc}} \) under a constant filtration pressure, \( \Delta p \), Darcy’s law is frequently used under the assumption that the pressure drop is constant throughout the cake. The following relationship is obtained where the cake permeability is \( k_{\text{fc}} \) and the filtrate viscosity is \( \mu_{\text{filt}} \).

\[
 h_{\text{fc}} = \sqrt{\frac{2k_{\text{fc}} w \Delta p}{\mu_{\text{filt}}}} \times t \quad (14-6)
\]

Expressed in terms of the API/ISO fluid loss of the slurry, \( V_{\text{API}} \), the cake height is

\[
 h_{\text{fc}} = w \times \frac{V_{\text{API}}}{A_{\text{API}}} \times \sqrt{\frac{\Delta p}{\Delta p_{\text{API}}}} \times \sqrt{\frac{t}{t_{\text{API}}}}, \quad (14-7)
\]

where the subscript API refers to API/ISO conditions: \( A_{\text{API}} = 3.5 \text{ in.}^2 \), \( \Delta p_{\text{API}} = 1,000 \text{ psi} \), and \( t_{\text{API}} = 30 \text{ min} \). The time required to build a cake of height \( h_{\text{fc}} \) is therefore

\[
 t = t_{\text{API}} \left( \frac{h_{\text{fc}} A_{\text{API}}}{w V_{\text{API}}} \right)^2 \frac{\Delta p_{\text{API}}}{\Delta p} \approx \frac{6.1 \times 10^7}{w V_{\text{API}}} \left( \frac{h_{\text{fc}}}{w V_{\text{API}}} \right)^2. \quad (14-8)
\]
Using this simple approach, the time required to build a 2-in. [5.1-cm] thick cake with a slurry having an API/ISO fluid-loss rate of 80 mL/30 min under a differential pressure of 500 psi [3.5 MPa] is

\[
t = 6.1 \times 10^7 \left( \frac{5 \text{ cm}}{1.3 \times 80 \text{ mL}} \right)^2 = 180 \text{ min.}
\]

It is important for the reader to realize that the above equations provide an approximate model to determine the relative orders of magnitude of relevant squeeze cementing parameters. Some caution should be exercised when attempting to use these equations to describe real downhole conditions.

Hook and Ernst (1969) gave orders of magnitude of the time required to build 2-in. [5.1-cm] thick filtercakes as a function of the API/ISO fluid-loss value (Table 14-3). This cake height is accepted as a good estimate of what is needed to fill perforations and build cement nodes (Fig. 14-25).

Table 14-3 is a compilation of permeability measurements conducted on filtercakes formed with different concentrations of a fluid-loss additive in the original cement slurry. The permeability of a neat-cement filtercake was about 5 mD—a value lower than that of many producing sandstone formations. When the slurry contained sufficient fluid-loss additive to reduce the API/ISO fluid-loss rate to 25 mL/30 min, the resulting filtercake was approximately 1,000 times less permeable. This value approaches the permeability of matrix formations that produce very slowly and have a low injectivity.

![Table 14-3. Filtercake Permeability and Slurry-Dehydration Rate†, ‡](image)

<table>
<thead>
<tr>
<th>Concentration of Fluid-Loss Additive (gal/sk)</th>
<th>API/ISO Fluid Loss at 1,000 psi (mL/30 min.)</th>
<th>Permeability of the Filtercake Formed at 1,000 psi (mD)</th>
<th>Time to Form a 2-in. Thick Filtercake (min.)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.00</td>
<td>1,200</td>
<td>5</td>
<td>0.2</td>
</tr>
<tr>
<td>0.07</td>
<td>600</td>
<td>1.6</td>
<td>0.8</td>
</tr>
<tr>
<td>0.13</td>
<td>300</td>
<td>0.54</td>
<td>3.4</td>
</tr>
<tr>
<td>0.17</td>
<td>150</td>
<td>0.19</td>
<td>14</td>
</tr>
<tr>
<td>0.19</td>
<td>100</td>
<td>0.09</td>
<td>30</td>
</tr>
<tr>
<td>0.22</td>
<td>50</td>
<td>0.009</td>
<td>100</td>
</tr>
<tr>
<td>0.24</td>
<td>25</td>
<td>0.006</td>
<td>300</td>
</tr>
</tbody>
</table>

† As a function of the fluid-loss-additive concentration. From Hook and Ernst (1969); reprinted with permission of SPE.
‡ API Class A cement with liquid fluid-loss additive and 46% water.

The data presented in Table 14-4 demonstrate the influence of squeeze pressure on the rate of filtercake growth. First, it shows that varying the squeeze pressure from 500 to 1,000 psi [3.5 to 6.9 MPa] does not influence the permeability of the resulting filtercake. Nevertheless, in keeping with Darcy’s law, the data show that the flow rate of fluid through the filtercake is directly proportional to the squeeze pressure.

![Table 14-4. Effect of Differential Pressure on the Permeability of Filtercakes and the Filtration Rate†, ‡](image)

<table>
<thead>
<tr>
<th>Differential of Filtercake Formation (psi)</th>
<th>Permeability of Filtercake (mD)</th>
<th>API/ISO Fluid Loss at 1,000 psi (mL/30 min.)</th>
<th>Flow Rate Through Filtercake (mL/min)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Slurry I†</td>
<td>500</td>
<td>5.8</td>
<td>1,200</td>
</tr>
<tr>
<td></td>
<td>1,000</td>
<td>6.0</td>
<td>1,200</td>
</tr>
<tr>
<td>Slurry II††</td>
<td>500</td>
<td>1.9</td>
<td>600</td>
</tr>
<tr>
<td></td>
<td>1,000</td>
<td>1.6</td>
<td>600</td>
</tr>
<tr>
<td>Slurry III‡‡</td>
<td>500</td>
<td>0.53</td>
<td>300</td>
</tr>
<tr>
<td></td>
<td>1,000</td>
<td>0.54</td>
<td>300</td>
</tr>
</tbody>
</table>

† From Hook and Ernst (1969); reprinted with permission of SPE.
‡ By increasing the pressure from 500 psi to 1,000 psi, the filtration rate is increased by a factor of about 2.
§ Class A cement, 45% water.
†† Class A cement with 0.5% dispersant, 0.07 gal/sk liquid fluid-loss additive, and 46% water.
‡‡ Class A cement with 0.5% dispersant, 0.13 gal/sk liquid fluid-loss additive, and 45% water.

![Fig. 14-25. Node buildup after a 45-min squeeze, using slurries with different fluid-loss rates (from Rike, 1973; reprinted with permission of SPE).](image)
Equation 14-7 provides only an estimate of filtercake growth, especially when the formation has a low permeability. In this case, an appreciable part of the differential pressure is applied through the formation, and cake growth is much slower than Eq. 14-6 predicts. Hook and Ernst reported experimental data to support this fact by building cement filtercakes on various filtration media (Table 14-5). These data support another conclusion by Hook and Ernst: Cement cakes are indeed not compressible, and the cake permeability does not vary with the differential pressure.

Consequently, it is common practice to design the fluid-loss rate of a squeeze cementing slurry according to the formation properties, with high fluid-loss rates for low-permeability formations and low fluid-loss rates for high-permeability formations. For vuggy zones, Grant et al. (1990) reported success with a two-slurry squeeze design. A lead slurry with a short pumping time and a fairly high API/ISO fluid-loss rate (300–500 mL/30 min) is followed by a tail slurry with a longer pumping time and lower fluid-loss rate. The tail slurry is used for hesitation.

Binkley et al. (1958) performed a more detailed analysis of perforation squeezing. They accounted for the successive perforation filling followed by node buildup according to the geometry shown in Fig. 14-26. The squeezing process is divided into three successive steps:

1. filling of perforation tunnels located inside the formation
2. filling of perforation tunnels crossing the casing and cement sheath
3. building cement nodes.

Step 1. The depth of the perforation is considered large in relation to its diameter (at least four times greater). This allows one to assume that the cake builds up radially inside a cylindrical perforation of radius \( r_{\text{perf}} \). Assuming that the pressure drop in the formation is zero, Binkley et al. demonstrated that the time required to build a filtercake filling the perforation tunnel inside the formation can be expressed by the following equation.

\[
t = \frac{\mu_{\text{filt}}}{k_{\text{form}}} \times w \times \Delta p \times \left( \frac{r_{\text{perf}}}{2} \right)^2
\]

(14-9)

The ratio

\[
\frac{\mu_{\text{filt}}}{k_{\text{form}}} \times w \times \Delta p
\]

contains all the variables related to the deposition properties of the cement slurry and is called the composition factor. It is interesting to note that, with the assumption regarding perforation depth versus its diameter, the depth of the perforation has no effect on the deposition process.

Step 2. For the second step, the flow is assumed to be linear along the axis of the perforation. The time required to build a filtercake in close contact with the inside of the casing can be calculated by the following equation.

\[
t = \frac{\mu_{\text{filt}}}{k_{\text{form}}} \times w \times \Delta p \times \left( \frac{h_{\text{comb}}}{2} \right)^2 + \left( k \times r_{\text{perf}} \times h_{\text{comb}} \right)
\]

(14-10)

where \( h_{\text{comb}} \) is the combined thickness of the cement sheath and casing and \( K \) is a factor that was used to fit the experimental data and was determined to be 0.25.

### Table 14-5. Effect of Formation Permeability on the Rate of Filtercake Growth

<table>
<thead>
<tr>
<th>Slurry</th>
<th>Time required for the formation of a 1½-in. filtercake on a 1-in. diameter filtration surface at 1,000 psi</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Bandera Sandstone 30 mD</td>
</tr>
<tr>
<td>Slurry I(^\dagger)</td>
<td>6 min</td>
</tr>
<tr>
<td>Slurry II(^\ddagger)</td>
<td>9 min</td>
</tr>
<tr>
<td>Slurry III(^\S)</td>
<td>5 min</td>
</tr>
</tbody>
</table>

\(^\dagger\) From Hook and Ernst (1969); reprinted with permission of SPE.
\(^\ddagger\) API Class A cement with 0.5% dispersant, 0.14 gal/sk liquid fluid-loss additive, and 46% water.
\(^\S\) API Class A cement with 0.7% solid fluid-loss additive and 46% water.
Step 3. To simplify the calculation, Binkley et al. (1958) assumed that the nodes building inside the casing have a spherical shape at every stage of growth and that the lateral growth occurs at the same rate as the vertical growth. The geometry is illustrated in Fig. 14-26. If \( h_{node} \) is the height of the node building up inside the casing, Eq. 14-11 can be derived.

\[
\frac{d h_{node}}{d t} = \frac{k_{form} \times w \times \Delta p}{\mu_{filt}}
\times \left[ \frac{1}{\left( h_{comb} + \beta + (K \times r_{perf}) \right)} \left( \frac{r_{o}}{r_{i}} \right)^{2} + \left( \frac{r_{o}}{r_{i}} \right)^{2} - r_{o} \right]
\]

(14-11)

where

\( h_{comb} \) = combined thickness of the cement sheath and casing

\( K = 0.25 \)

\[
r_{i} = \sqrt{\left( r_{o} - h_{node} \right)^{2} + \left( r_{perf} \right)^{2}}
\]

\[
r_{o} = \frac{\left( h_{node} \right)^{2} + \left( r_{perf} + h_{node} \right)^{2}}{2h_{node}}
\]

\( r_{perf} \) = radius of the perforation

\( \beta = r_{i} - \sqrt{\left( r_{i} \right)^{2} - \left( r_{perf} \right)^{2}} \).

This equation was integrated numerically. The three calculated times are then added, and the results are plotted in Fig. 14-27. Using dimensionless variables, these results represent the time required to fill a perforation and build a node, versus the ratio \( h_{comb}/r_{perf} \), for different node heights \( h_{node}/r_{perf} \).

The bottom curve, \( h_{node}/r_{perf} = 0 \), represents the times required to obtain a cake that is flush with the inside of the casing.

In actual squeeze operations, the squeeze pressure is increased in steps. Provided the cement cake is truly incompressible, Eqs. 14-6 and 14-7 remain valid if the filtration pressure is replaced by an effective filtration pressure, \( \Delta p_{e} \), equal to the time-average of the actual filtration pressure,

\[
\Delta p_{e} = \frac{\sum \Delta p_{i} t_{i}}{\sum t_{i}},
\]

(14-12)

where \( p_{i} \) = pressure for a step of duration \( t \). For slightly compressible cakes, Eq. 14-6 and 14-7 can still be used provided the cake properties are measured at the effective filtration pressure.

14-9 Squeeze cementing tools and techniques

There are two traditional and fundamentally different squeeze job classifications.

- Low-pressure squeeze: The bottomhole treating pressure is maintained below the formation fracturing pressure.
- High-pressure squeeze: The bottomhole treating pressure exceeds the formation fracturing pressure.

Within these two classes, there are two basic techniques (the Bradenhead squeeze and the squeeze-tool technique) and two pumping methods (the running squeeze and the hesitation squeeze). Each of these classifications and techniques is explained in this section. These techniques are also compared and contrasted in Tables 14-6, 14-7, and 14-8.
### Table 14-6. Comparison of High-Pressure and Low-Pressure Squeeze Techniques

<table>
<thead>
<tr>
<th>Features</th>
<th>High Pressure</th>
<th>Low Pressure</th>
</tr>
</thead>
<tbody>
<tr>
<td>Induces fractures in the formation that allow cement to replace the dirty fluid in the wellbore</td>
<td>Offers the best option for squeezing the pay zone</td>
<td>Uses small volume of slurry</td>
</tr>
<tr>
<td>Offers the best option for squeezing the pay zone</td>
<td>Avoids fracturing the formation</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Applications</th>
<th>When</th>
<th>In</th>
</tr>
</thead>
<tbody>
<tr>
<td>“dirty” wellbore fluids must be displaced to allow placing the cement into a void</td>
<td>multiple zones</td>
<td></td>
</tr>
<tr>
<td>there is mud in the hole that must be displaced before cement can enter the voids</td>
<td>long intervals</td>
<td></td>
</tr>
<tr>
<td>there are no voids to fill, e.g., shoe squeeze, block squeeze, or when cementing liner top</td>
<td>wells with low bottomhole pressure</td>
<td></td>
</tr>
</tbody>
</table>

| Disadvantages | Larger slurry volumes will be required to fill the additional void space created by the fracture. It may be difficult to develop filtercake in the fracture. Squeeze pressure may be difficult to attain. | More careful design and execution is required. |

### Table 14-7. Comparison of Running- and Hesitation-Squeeze Techniques

<table>
<thead>
<tr>
<th>Applications</th>
<th>Running Squeeze</th>
<th>Hesitation Squeeze</th>
</tr>
</thead>
<tbody>
<tr>
<td>Only when</td>
<td>Easy to apply</td>
<td>Self-diverting technique</td>
</tr>
<tr>
<td>fluids are clean</td>
<td>Simple slurry design, little fluid-loss control needed</td>
<td>Better way of filling all the voids and creating a complete hydraulic seal</td>
</tr>
<tr>
<td>the formation is free from fractures or interconnected voids</td>
<td>Good chance of obtaining final squeeze pressure under correct conditions</td>
<td>Achievement of “squeeze pressure” a relatively good indicator of success</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Advantages</th>
<th>Disadvantages</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Easy to apply</td>
<td>Attaining a squeeze pressure is not a reliable indicator of success. The method cannot be relied upon to fill all voids. The method can only be carried out with clean fluids in the hole.</td>
<td>Job procedure is more complicated. Cement placement time is longer, resulting in increased time WOC. Squeeze tool placement is more critical. The procedure requires a skilled supervisor with an ability to “feel the well” to modify job execution, including</td>
</tr>
<tr>
<td>Simple slurry design, little fluid-loss control needed</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Good chance of obtaining final squeeze pressure under correct conditions</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>cement volume</td>
</tr>
<tr>
<td></td>
<td></td>
<td>pumping rate</td>
</tr>
<tr>
<td></td>
<td></td>
<td>stage volume</td>
</tr>
<tr>
<td></td>
<td></td>
<td>hesitation time.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Slurry design is more complex, because</td>
</tr>
<tr>
<td></td>
<td></td>
<td>pumping time testing procedure must account for hesitation periods</td>
</tr>
<tr>
<td></td>
<td></td>
<td>low gel strength is needed during hesitation periods</td>
</tr>
<tr>
<td></td>
<td></td>
<td>requirements for fluid loss will vary depending on nature of voids and permeability.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Well Cementing
14-9.1 Low-pressure squeeze

As discussed earlier, the aim of a squeeze operation is to fill perforation cavities and interconnected voids with cement filtercake, with a small “node” protruding inside the casing. The cement-slurry volume is usually small, because no slurry is actually pumped into the formation. Precise control of the pump pressure and the hydrostatic pressure of the cement column is essential because excessive pressure could result in formation breakdown.

In low-pressure squeezes, it is essential that perforations and channels be clear of mud or other solids. If the well has been producing, such openings may already be free of obstructions; however, for newly completed wells, it may be necessary to clean the perforations before performing the squeeze job (Section 14-9.9).

A properly designed slurry will leave only a small node of cement filtercake inside the casing. Improperly designed systems that cause excessive filtercake development can lead to complete bridging of the inside of the casing, loss of pressure transmission to the formation, and insufficient contact of the cement filtercake with the formation.

Review of the literature shows that most authors believe a low-pressure squeeze should be run whenever possible and that this technique has the highest success rate (Rike and Rike, 1981; Goodwin, 1984; Bradford and Reiners, 1985).

14-9.2 High-pressure squeeze

In some cases, a low-pressure squeeze of the perforations will not accomplish the job objective. The channels behind the casing may not be directly connected to the perforations. Small cracks or microannuli that may allow gas flow do not allow the passage of a cement slurry. Such channels must be enlarged to accept viscous solids carrying fluid. In addition, many low-pressure operations cannot be performed if it is impossible to remove plugging fluids or debris ahead of the cement slurry or inside the perforations.

Cement-slurry placement behind the casing is accomplished by breaking down, or fracturing, the formation at or close to the perforations (Fig. 14-28). Fluids ahead of the slurry are displaced in the fractures, allowing the slurry to fill the desired spaces. Further application of pressure dehydrates the slurry against the formation walls, leaving all channels (from fractures to perforations) filled with cement cake.

However, during a high-pressure squeeze, the location and orientation of the created fracture cannot be controlled. Sedimentary rocks usually have a low tensile strength and are held together primarily by the compressive forces of overlying formations. These cohesive forces act in all directions to hold the rock together but do not have the same magnitude in all directions. When sufficient hydraulic pressure is applied against a
formation, the rock fractures along the plane are perpendicular to the direction of the least principal stress (Fig 4-29). A horizontal fracture is created if the fracturing pressure is greater than the overburden pressure. A vertical fracture occurs if overburden pressure is greater (Roegiers, 1989).

The extent of the induced fracture is a function of the pump rate applied after the fracture is initiated. The amount of slurry used depends on the way the operation is performed. High pump rates generate large fractures; thus, large volumes of cement are required to fill them. A properly performed high-pressure squeeze should place the cement as close to the wellbore as possible.

Drilling muds or other fluids with low fluid-loss rates should not be pumped ahead of the slurries. A wash with a high fluid-loss rate, such as water or a weak hydrochloric acid solution, not only opens smaller fractures but also cleans perforations and the cement path. As a result, the fracture initiation pressure is lower.

14-9.3 Running squeeze method

During a running squeeze procedure, the cement slurry is pumped continuously until the final desired squeeze pressure—which may be above or below the fracture pressure—is attained. The pressure is monitored after pumping stops. If the pressure falls owing to additional filtration at the cement/formation interface, more slurry is pumped to maintain the final squeeze pressure. This continues until the well maintains the squeeze pressure for several minutes without additional cement-slurry injection. The volume of slurry injected is usually large. Rike and Rike (1981) reported that volumes ranging from 10 to 100 bbl are commonly used. A modified running squeeze technique, using pumps that can deliver several barrels of slurry at rates as low as 0.06 bbl/min [10 L/min] to avoid formation fracturing, has been used successfully to seal narrow microannular gaps (Slater et al., 2001).

14-9.4 Hesitation squeeze method

During a squeeze cementing job, the rate at which cement filtrate leaks into the formation is lower than the minimum pump rate of most field equipment. Therefore, maintaining a constant differential pressure is nearly impossible, especially when one is trying not to exceed the formation fracture pressure.

A solution to this problem is the hesitation squeeze pumping method. This procedure involves the intermittent application of pressure—by pumping at a rate of ¼ to ½ bbl/min—separated by an interval of 10 to 20 min for pressure falloff caused by filtrate loss to the formation. The initial leakoff is normally fast because there is
no filtercake. As the cake builds up and the applied pressure increases, the filtration periods become longer and the differences between the initial and final pressures become smaller. At the end of the job, the pressure falloff becomes negligible (Fig. 14-30). The slurry volumes necessary for this technique are usually much less than those required for a running squeeze.

A loose formation normally requires a long hesitation period to begin building squeeze pressure. A first hesitation period of 30 min or more is not unreasonable. A much shorter initial hesitation period (possibly 5 min) is normally sufficient for tight formations (Grant and White, 1987). Instead of prescribing pump times, the best method is to continue pumping as long as squeeze pressure continues to build.

14-9.5 Bradenhead squeeze (no packer)

The Bradenhead squeeze technique, illustrated in Fig. 14-31, is a low-pressure squeeze technique practiced when there are no doubts concerning the casing’s ability to withstand the squeeze pressure. No special tools are involved, although a bridge plug may be required to isolate other open perforations farther downhole.

Open-ended tubing is run to the bottom of the zone to be cemented. Blowout preventer (BOP) rams are closed over the tubing, and an injection test is performed. The cement slurry is subsequently spotted in front of the perforations. Once the cement is in place, the tubing is pulled out to a point above the cement top, the BOPs are closed, and pressure is applied through the tubing. The Bradenhead squeeze is popular because of its simplicity.

14-9.6 Squeeze-tool placement technique

This technique can be subdivided into two parts—the retrievable squeeze packer method and the drillable cement retainer method. The main objective of using squeeze tools is to isolate the casing and wellhead while applying high pressure downhole.

14-9.6.1 Retrievable squeeze packer method

Retrievable packers with different design features are available (Chapter 11; Savage and Fowler, 1994). Compression- or tension-set packers are used in squeeze cementing. As shown in Fig. 14-32, they have a bypass valve to allow the circulation of fluids while running in the hole and after the packer is set. This feature allows tool cleaning after the cement job and reversing out excess slurry without excessive pressure. The bypass valve also prevents a piston or swabbing effect while running in or out of the hole.

The principal advantage of the retrievable packer over the drillable retainer is its ability to set and release many times, allowing more flexibility.
14-9.6.2 Drillable cement retainer

Cement retainers are drillable packers that have a valve that is operated by a stinger at the end of the workstring (Fig. 14-33). Cement retainers are used to prevent backflow when no cement dehydration is expected or when a high negative differential pressure may disturb the cement cake. In certain situations, using a packer is risky because of potential communication with upper perforations. When cementing multiple zones, the cement retainer isolates the lower perforations and subsequent zone squeezing can be performed without waiting for the slurry to set.

A drillable retainer gives the operator more confidence in setting the packer closer to the perforations. Another advantage is that a smaller volume of fluid below the packer is displaced through the perforations ahead of the cement slurry.

14-9.7 Perforation washing tool

Perforation washing before a squeeze job is a useful method for making all perforations receptive to the squeeze cement slurry. This can be done by mechanical or chemical means.

Mechanical perforation washing involves the use of a washing tool coupled with back-surge techniques. The perforation-washing tool (Fig. 14-34) isolates a small number of perforations at a time. A wash fluid is pumped down the tubing and forced into the perforations. It is then forced outside the casing and back through upper perforations into the annulus. The tool is slowly moved upward to wash the entire perforated interval. Common wash fluids are surfactant solutions, followed by weak acids when scales or drilling muds are to be removed. Organic solvents are used when paraffin deposits are present.

The surge tool (Fig. 14-35) is basically an air chamber between an upper and lower valve. The tool is run in the hole with a packer to isolate the desired interval. Once the packer is set, the lower valve is opened so fluids can enter the air chamber. The rapid depressurization of the borehole creates a high differential pressure across the perforations, inducing the removal of debris and other plugging materials. To establish circulation after surging, the upper valve is opened (by means of tubing movement, tubing pressure, or disk rupturing), and the debris is reverse-circulated out of the hole.
Chemical perforation cleaning techniques involve pumping acids and solvents as spearhead fluids to clean the perforations ahead of the cement slurry. Sometimes the injectivity decreases after an acid job, owing to emulsions formed by the formation fluid and the acid. Prejob compatibility tests should be performed to prevent this problem and select the best acid-surfactant combination.

14-9.8 Squeeze with coiled tubing

The use of coiled tubing for remedial cementing began in the early 1980s. Since then, the technique has gained considerable popularity (Walker et al., 1992; Loveland and Bond, 1996). Squeeze cementing with coiled tubing is similar to that using drillpipe. Specialized tools can be run through tubing, such as small outside diameter (OD) and inflatable packers (Fig. 14-32) (Wilson et al., 2004).

Coiled tubing has proved to be a very economical method to accurately place the small volumes of cement slurry usually involved in remedial cementing operations. Harrison and Blount (1986) reported that, in some instances, up to 85% savings on workover costs can be achieved when using coiled tubing.

As illustrated in Fig. 14-36, the procedure can be divided into several steps.

- A supporting column of mud (viscous pill) is injected until its level is just below the perforations to be squeezed. Some mud contamination may occur during placement because of mixing with wellbore fluids; thus, the coiled tubing string nozzle is pulled up, and contaminated mud is circulated out. The wellbore above the mud is then loaded with water or diesel.

- Cement is pumped with the nozzle located just above the mud/water interface. When the perforations are covered with cement slurry, squeeze pressure is applied. The nozzle must be kept below the water/cement interface.

- After the squeeze pressure is reached, a contaminant fluid is injected to dilute the cement slurry, the contaminated cement and mud are reversed out, and the wellbore is flushed clean.
This technique has suffered from a few specific drawbacks: poor depth control, pipe-volume errors, and fluid contamination (Noles et al., 1996).

- Pessin and Boyle (1997) reviewed the various factors and causes of errors in depth measurement and proposed an improved measurement that provides the required accuracy.
- A good knowledge of the coiled tubing volume is mandatory for placing small slurry volumes. Indirect measurements are unreliable. One should directly monitor the volume of the tubing on its reel.
- When low volumes of slurry are placed, fluid contamination may be prevented by using mechanical plugs such as foam balls (Loveland and Bond, 1996).

**14-10 Squeeze cementing—Cement-slurry design**

For squeeze cementing, the selection of a fluid or sequence of fluids must be tailored to the type of treatment, the technique to be used, and the nature of the voids. It is not uncommon that more than one candidate slurry is prepared and the final slurry selection is made at the wellsite based on last-minute information. Frequently, the decision is based upon the results of the injection test.
14-10.1 Slurry selection
The properties of a squeeze-cement slurry must be tailored to the formation characteristics and the squeeze technique. The slurry properties are important in three respects:

- to allow proper placement from surface to downhole
- to allow fluid placement behind the casing or in the perforations
- to obtain the desired properties of the set material.

Many types of slurries have been used for remedial cementing, from standard Portland cement systems to sophisticated systems adapted from civil engineering. It is generally agreed that a squeeze cementing slurry should be designed to have the following general attributes:

- low viscosity—to allow the slurry to penetrate small cracks
- low gel strength during placement—because a gelling system restricts slurry movements and causes increases in surface pressure that are difficult to interpret
- appropriate cement particle size
- no free water
- appropriate fluid-loss control—to ensure optimal filling of the cracks or perforations
- proper thickening time—to safely meet the anticipated job time.


14-10.2 Fluid-loss control and filtercake development
The requirements for fluid-loss control are defined so that the desired filtercake forms, with properties depending upon the formation and the type of voids to be filled. In addition, the relationship between API/ISO fluid-loss volume and filtercake properties is dependent upon the slurry composition.

- One method is to tailor the API/ISO fluid-loss rate to the formation permeability, with low fluid-loss volumes (less than 100 mL/30 min) for formations with permeabilities less than 100 mD. This rule allows competent filtercakes to form within a reasonable time period.
- If large voids or fractures exist behind the casing and there is no flow restriction, high fluid-loss-rate slurries (300 to 500 mL/30 min) are initially applied to allow fast filtercake buildup in the voids, followed by a tail slurry with a lower fluid-loss rate for hesitation squeezing (Grant *et al*., 1990). Lost-circulation materials may also be added to bridge fractures. If the formation permeability is sufficiently high, a medium-to high-fluid-loss slurry (200 to 500 mL/30 min) will usually permit filtercake formation and subsequent diversion of slurry into smaller cracks.
- If the voids behind the casing are narrow channels into which deep penetration is required, such as channels or microfractures, then very good fluid-loss control (<50 mL/30 min) is required to prevent early slurry dehydration.

Appropriate fluid-loss rates are required to obtain optimal filtercakes. For example, a Portland cement system with a low fluid-loss rate will provide a hard filtercake that fills a perforation. Conversely, large nodes resulting from slurries with an excessive fluid-loss rate will be difficult to clean and may inhibit production by reducing the internal casing size.

14-10.3 Rheology and sedimentation
The requirements in terms of slurry rheology are often in conflict for squeeze jobs.

- The ability of the slurry to flow into narrow channels is a direct function of its fluidity. Thick slurries, although useful when cementing large voids, will not flow into small restrictions unless they are subjected to high differential pressures that may exceed the formation fracture pressure. Therefore, low-viscosity slurries containing dispersants are commonly used.
- Thin slurries are required when cement placement is performed through coiled tubing. Nowak *et al*., (1996) mention a maximum slurry viscosity of 60 cp.
- High slurry yield stress or gelation can lead to misinterpretation of surface-pressure readings during the pumping period. Gelation will prevent the application of the full pressure through the filtercake, and cake buildup will be impaired.
- If the slurry viscosity is too low, the slurry may exhibit free water and sedimentation, and its downhole properties will be unpredictable.
- When the slurry is placed off-bottom on a lighter fluid, and no mechanical base is available to prevent slumping, increasing the cement yield stress is a good way to decrease the risk of slumping.

14-10.4 Density
Better set-cement properties are usually correlated with high slurry density. However, high-density slurries tend to be viscous. The slurry density may also be limited to avoid excessive hydrostatic pressures during placement.
These contradictory requirements can be met by using engineered particle size slurries (Boisnault et al., 1999; Chapter 7) that allow the following:

- low-density slurries with good mechanical properties (Elmoniem et al., 2000)
- high-density slurries with relatively low viscosities (Pokhriyal et al., 2001).

14-10.5 Size of particles in the slurry

The size of an opening through which a slurry can flow is a direct function of the size of the largest particles (Chapter 6). For unconsolidated formations, there are some general guidelines.

- For a sand pack, the pore size is usually estimated to be one-fourth the sand-grain size. The permeability of the sand pack is proportional to the square of the pore size.
- Particles will flow through pores without bridging if they are smaller than about one-fifth the pore size.

With these two guidelines, one can estimate the largest allowable particle size versus the permeability of the porous medium. This leads to fluid-selection guidelines presented in Table 14-9.

For plugging gravel packs, organic compounds or synthetic cements based on epoxy chemistry have been used (Chapter 7; Chan and Griffin, 1996; Ng and Adisa, 1997), as well as small-particle-size cements (Chapter 7; Ewert et al., 1991; Faul et al., 1999; Keese et al., 2000; Fleming et al., 2000; Johannessen et al., 2000).

Foamed cements have been used to plug fractures (Creel and Crook, 1998) and squeeze high-permeability zones. Chmilowski and Kondratoff (1990; 1992) discussed the selection of slurry type based on the results of an injection test. For highly permeable reservoirs, foamed cement provided the highest probability of success.

Small casing leaks or low-rate vent flows have been successfully plugged in one attempt using engineered microcement (Chapter 7; Farkas et al., 1999; Slater et al., 2001).

Sometimes two slurries are used in sequence when all of the required properties cannot be obtained with a single fluid.

- A deep-penetrating fluid can be followed by a conventional cement slurry that builds a filtercake to obtain a squeeze pressure. The first fluid can be a small-particle-size cement slurry (Heathman et al., 1993; Bailey et al., 2000) or a solids-free silicate-base solution (Ness and Gatti, 1995).
- Grant et al. (1990) reported success with a two-slurry squeeze design for vugular zones. A lead slurry with a short pumping time and a fairly high API/ISO fluid-loss rate (300 to 500 mL/30 min) is followed by a tail slurry with a longer pumping time and a lower fluid-loss rate. The tail slurry is pumped using the hesitation-squeeze technique.
- A fast-setting slurry followed by one with a longer thickening time (Nowak et al., 1995) has been applied to repair a relatively large channel behind the casing.

14-10.6 Thickening time and temperature

As with primary cementing, the temperature and pressure are important factors that influence the thickening time of a cement slurry. For squeeze jobs, the thickening time is designed to allow for slurry placement, squeeze time, and well cleanout. The temperatures encountered during squeezing can be higher than those during primary jobs, because less fluid circulation and well cooling occur before the job. For this reason, special API testing guidelines (Appendix B; Cowan and Sabins, 1996) exist for squeeze cement-slurry design and should be followed to prevent premature thickening.

14-10.7 Chemical resistance

Like plug cementing systems, squeeze cementing systems often must be resistant to subsequent well stimulation treatments. The requirement is usually expressed in terms of solubility in HF-HCl acid systems. As dis-

<table>
<thead>
<tr>
<th>Mesh Number</th>
<th>µm</th>
<th>Permeability (D)</th>
<th>Pore Size (µm)</th>
<th>Maximum Particle Size (µm)</th>
<th>Fluid Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>10</td>
<td>2,000</td>
<td>234</td>
<td>500</td>
<td>100</td>
<td>Class G cement</td>
</tr>
<tr>
<td>60</td>
<td>250</td>
<td>4</td>
<td>62</td>
<td>13</td>
<td>Microcement</td>
</tr>
<tr>
<td>120</td>
<td>125</td>
<td>1</td>
<td>31</td>
<td>7</td>
<td>Solids-free treatment</td>
</tr>
</tbody>
</table>
cussed in Section 14-5, latex cement slurries and epoxy-base synthetic cements are especially resistant to these conditions. Achieving low cement permeability by combining small-particle-size cement and latex also provides enhanced acid resistance (Heathman et al., 1993).

14-10.8 Economics
Because they are workover operations, squeeze operations can be costly. As shown schematically in Fig. 14-37, the various costs to consider include the loss of production, problem diagnosis, implementing the repair solution, and evaluating the success of the job. Therefore, one must carefully justify such treatments economically. The cement slurry usually represents less than 10% of the total job cost. In addition, one should choose the fluid system that offers the best chance of success, even if it is more costly.

14-11 Job design
14-11.1 Volume selection
The optimal slurry volume for squeeze cementing tends to be determined by best practices and common rules rather than rigorous methodology. This is mainly caused by the large number of unknowns, especially the hole size.

- For filling voids behind casing, the proper use and interpretation of injection tests provides a good initial estimate of the void volume and hence the volume of cement slurry to use.
- Plugging perforations and small leaks with a low-pressure squeeze requires only enough slurry to build a cement filtercake in each perforation tunnel. In many cases, less than a barrel would be sufficient. However, for job convenience, a 5- to 15-bbl batch is normally prepared. Another approach is to use two sacks of cement per foot of perforated interval, with a minimum amount of 50 sacks per job (Smith, 1987).
- A high-pressure squeeze, in which the formation is fractured, requires a higher volume of slurry. The volume required is a function of the width and depth of the fractures created. Rike and Rike (1981) reported that, during some running squeezes in which fracturing was excessive, volumes exceeding 100 bbl of slurry were injected.
- The slurry volume can be minimized by fracturing at a low pump rate and below the fracture-propagation pressure. If the squeeze is performed at high pressures and pump rates, the fractures will develop accordingly, resulting in large quantities of cement being pumped in the formation.

Other constraints that limit the slurry volume include the following.
- The hydrostatic and surface pressures must be controlled during the job. A high cement column during displacement could cause the breakdown of low-pressure or depleted formations. When large quantities of cement are necessary (natural fractures), low-density slurries should be used.
- The volume should not exceed the capacity of the run-in string.
- The volume should not form a column that cannot be reversed out.
- When placing the slurry with coiled tubing, the weight of the tubing filled with cement must be within the tubing tensile-strength limit.

Equations to calculate the fluid volumes for squeeze cementing, as well as the pressures at various points in wellbore during the treatment, are presented in Appendix C.

14-11.2 Spacers and washes
Spacers and washes have three main roles in squeeze cementing.

- They prevent contamination of the cement slurry.
- They help clean voids and perforations that must be filled with cement.
- Often, the tubulars have been in place for a long time and are covered with rust, debris, inorganic scales, or organic deposits. Spacers and washes help remove such materials and push them ahead of the cement slurry.
In squeeze cementing, cement-slurry contamination may be especially troublesome because the volumes are often small, and slurry properties such as thickening time, fluid-loss rate, and viscosity can be seriously affected. The final two objectives can be met by performing a pretreatment step during which cleaning fluids are pumped ahead of the main treatment sequence. Devices such as perforation washing tools are used with acids to clean perforations (Section 14-9.9). Acids also weaken the formation structure and reduce the breakdown pressure for high-pressure squeeze treatments. Acids, surfactants, and viscous fluids may be used in combination with jetting devices to clean the inside of the tubulars.

Prevention of fluid mixing in the pipe is best achieved by isolating the fluids with mechanical devices (balls, darts, etc.) rather than with spacers. However, spacers are required to help displace the fluid in the hole by cement. The process of mud removal is similar to primary cementing (Chapters 5 and 13), and the same general rules concerning mud conditioning, density, and rheology hierarchy still apply. However, the conditions are different in a few respects.

- The pipe tip is seldom centralized. It lies on the hole wall, and a small amount of mud is likely to remain trapped along this contact line.
- To limit the amount of trapped mud, the pipe should be rotated during placement (not reciprocated).
- When placing the slurry with coiled tubing, the general rule is to pull the tubing at the same speed as the cement velocity in the annulus, keeping the coiled tubing tip a few tens of feet below the upper cement interface.

14-11.3 Displacement volume for a squeeze operation

The maximum displacement volume for a cement squeeze operation corresponds to the volume from the surface down to the top perforations to be squeezed. A safety margin is added, usually a few barrels. Like balanced plugs, the maximum displacement volume for squeeze operations may be uncertain owing to factors such as pump efficiency, variability of the internal pipe volume, and fluid compressibility. Fluid compressibility is particularly important for the following reasons.

- The pressure attained during a squeeze operation is much greater than that attained during primary cementing, so fluid compressibility plays a larger role. When the squeeze is performed in an openhole section, the formation has a tendency to expand, leading to a hole-volume increase.

- The duration of a squeeze operation can be long, and the cement-slurry temperature will have more time to equilibrate with the formation temperature.

For a Bradenhead squeeze, the casing may also expand if it is unsupported on the low-pressure side. The following example provides estimates of the expected volume variations owing to fluid-pressure and temperature changes.

Consider a 5-in. drillpipe, 5,000 ft [1,524 m] long, filled with a 11.7-lbm/gal [1,400-kg/m³] fluid. The compressibility of the fluid is \(4 \times 10^{-10} \text{ Pa}^{-1}\), and its coefficient of thermal expansion is \(4 \times 10^{-4} \text{ K}^{-1}\). Under its own weight, the fluid will compress by 0.43% (16 gal [0.061 m³]). This is the extra volume required to fill the pipe in a vertical well. If the fluid is heated to the formation temperature (assuming a geothermal gradient of 2.4°C/100 m), the fluid will expand by 0.33% (12 gal [0.046 m³]). To apply a surface pressure of 3,000 psi [21 MPa], 0.50% of the pipe volume must be pumped (18 gal [0.070 m³]). Overall, the uncertainty in fluid volume is around 1%, which translates to 49 ft [15 m] in depth.

14-11.4 Pressure and mechanical strength checks

Three basic safety limits must be monitored at all times during the various stages of the operation, including cement placement, squeeze, and cleanout.

- For low-pressure squeezes, the dynamic fluid pressure in front of the formation must be less than the formation fracturing pressure. This constraint may be exceeded at the end of a successful squeeze operation.
- The static fluid pressure in front of the formation must be higher than the pore pressure to prevent any formation fluid entry.
- The differential pressure across the various tubulars must be less than their burst or collapse pressures. When working with coiled tubing, the weight of tubing filled with cement must remain within the tubing tensile-strength limits. One must also account for coiled tubing fatigue.

The differential pressure across tubulars must allow for unexpected occurrences. For example, when using a cement retainer for a squeeze operation, the fluid may flow upward into the annulus and pressurize the outside of the casing above the retainer. To prevent casing collapse in these situations, it is a common practice to pressurize the pipe-casing annulus (Fig. 14-38).

After the squeeze treatment, the pressures exerted during reverse circulation must be considered. If the formation is weak, reverse circulation is usually not recommended.
14-12 Injection test

Before mixing and pumping the cement slurry, an injection test is performed. This procedure consists of pumping a fluid, typically water, into the well. The injection test is performed for several reasons:

- to ensure that the perforations are open and ready to accept fluids (for small leaks, an injection test helps determine whether it will be possible to inject a fluid, and the expected treatment pressure and rate)
- to obtain an estimate of the proper cement-slurry injection rate
- to estimate the pressure at which the squeeze job will be performed
- to estimate the volume of slurry to be used (for a flow behind casing, an injection test helps determine the volume of voids behind casing and the necessary treatment-fluid volume).

Should the fluid fail to achieve injection, acid is often injected under matrix conditions. Hydrochloric and hydrofluoric acids are commonly used.

For a water production problem, an injection test may be an additional aid to determine whether water is flowing through fractures or the rock pores. This test will also aid the selection of the appropriate chemical system for the treatment.

Grant et al. (1990) and Chmilowski and Kondratoff (1992) presented some basic guidelines for the design, execution, and interpretation of injectivity tests. They are detailed below.

14-12.1 Determination of injection pressure and rate

The goal of the injectivity test is to collect data about the expected pressure to be applied during a low-pressure squeeze treatment. Depending on the measured pressure, a perforation wash treatment may be applied before the squeeze job to increase injectivity or the squeeze-fluid composition may be altered.

The test consists of injecting a fluid such as water through the perforations for several minutes at a rate close to that used in a squeeze treatment, until a pseudo-steady-state regime is reached. Care is taken to avoid reaching the formation fracturing pressure (Chmilowski and Kondratoff, 1992). The most important factors to consider are the following.

- The friction pressure developed as the fluid flows through the pipe should be calculated and subtracted from the pump pressure. If possible, monitor the annular pressure.
- To prevent perforation plugging, the injected fluids must be clean, and the wellbore should be circulated before injection.
- The injection should proceed until the pressure stabilizes, typically 10–15 min.
- The injection rate should be maintained below the fracturing pressure.
- Operational procedures should be consistent between different wells in the same field to obtain meaningful comparisons.

In general, as the injectivity decreases, the importance of the fluid design increases.

- Grant et al. (1990) found that a single slurry with good fluid-loss control is appropriate for tight formations. For loose formations, a lead slurry with a high fluid-loss rate (300–500 mL/30 min) is recommended, followed by a tail slurry with a low fluid-loss rate.
- Chmilowski and Kondratoff (1992) recommend a Class G slurry with a low fluid-loss rate for formations with low injectivity, Class G and microspheres for intermediate injectivities, and foamed cement for high injectivities.

14-12.2 Determination of void volume behind casing

For flow behind casing, an injection test helps determine the volume of voids behind the casing and the ultimate treatment-fluid volume. The concept is to pump a viscous fluid that creates a measurable injection-pressure increase when it reaches the formation face. The void volume is approximated by the total volume pumped when the pressure increase occurs.
To perform a useful injection test, the following factors must be considered:

- A fluid with a viscosity between 50 and 200 cp should be used. The tighter the formation, the lower the viscosity should be. The viscosity should be measured at the anticipated treatment temperature.

- The fluid should be clean to facilitate flow through the formation. Fully hydrated biozan, xanthan, or polyacrylamide fluids are suitable.

- If a preliminary estimate of the void volume is unavailable, the injection-fluid volume should be 2 to 3 times the annular volume between the casing and the formation, using the height estimated from cement logs or lithology logs.

- The fluid must be pumped at a constant flow rate, and the pressure must be closely monitored. Ideally, a downhole pressure sensor should be used, especially if coiled tubing is involved. All acquisition systems should be synchronized.

- After the test is complete, the injection fluid should be cleaned out of the well, either by producing it or breaking it. This prevents problems caused by incompatibility between the polymer and the treatment fluid.

14-12.3 Determining the nature of flow paths behind casing

For a water production problem, flow tests have been used to determine the type of flow in the formation. The results help determine the appropriate chemical treatment. A traditional means of interpreting pressure-volume data from water injection wells is the Hall plot (Buell et al., 1987). This analysis applies to situations in which a fluid is injected radially in a porous medium, and Darcy’s law applies. The integral of the pressure is plotted versus the cumulative volume pumped, $V_{cum}$. The slope of the curve, $\alpha$, provides information about the formation according to the following equation.

$$\int \Delta p \, dt = \alpha V_{cum} \quad (14-13)$$

with

$$\alpha = \frac{\mu}{2\pi k_{form} h_{form}} \left( \ln \frac{r_{ext}}{r_{wb}} + s \right).$$

In this equation, $r_{ext}$ is the external drainage radius, $r_{wb}$ the wellbore radius, $s$ the skin factor, $k_{form}$ the formation permeability, and $h_{form}$ the formation thickness.

Alternative methods are available in specific cases. When a viscous fluid is used to displace a less viscous fluid in the formation, the equations can be simplified into the following form.

$$\frac{q}{p_{wb} - p_{res}} = \frac{4\pi k_{form} h_{form}}{\mu} \times \frac{1}{\log \left( \frac{V_{cum}}{V} + 1 \right)} \quad (14-14)$$

The injectivity index,

$$\frac{q}{p_{wb} - p_{res}},$$

is plotted versus an expression of the volume pumped. $p_{res}$ is the reservoir pressure and $V$ the wellbore volume times the porosity. Similar derivations can be made for a variety of flow geometries (e.g., fractures), which allows one to select the conditions that best fit the measured data.

14-13 Basic squeeze-job procedures

The general sequence of events during a squeeze job is detailed below.

1. Zones below the interval to be squeezed are isolated with a retrievable or drillable bridge plug.

2. The perforations are washed with a perforation washing tool or are reopened with the back-surgering technique (Sections 14-9.9 and 14-9.10).

3. The perforation washing tool is retrieved and, if the packer method is chosen, it is run in the hole with the workstring, set at the desired depth and tested. A test pressure of 1,000 psi [6.9 MPa] is usually sufficient. If the cement is to be spotted in front of the perforations, a tailpipe covering the length of the zone plus 10 or 15 ft [3 or 5 m] is run below the packer.

4. An injection test is performed using clean, solids-free water or brine. If a low-fluid-loss completion fluid is in the hole, it must be displaced from the perforations before starting the injection test. This test gives information concerning the permeability of the formation to the filtrate.

5. The spearhead fluid followed by the cement slurry is circulated downhole with the packer bypass open. This circulation is performed to avoid squeezing damaging fluids ahead of the slurry into the formation. A small amount of backpressure is applied on the annulus to prevent slurry free-fall as a result of the U-tube effect.
If no tailpipe has been run, the packer bypass must be closed 2 to 3 bbl before the slurry reaches the packer. If the cement is to be spotted in front of the perforations with the packer unset, circulation is stopped as soon as the cement covers the selected zone. The tailpipe is pulled out of the cement slurry, and the packer is set at the desired depth.

The depth at which the packer is set must be carefully chosen. If a tailpipe is run, the minimum distance between the perforations and the packer is limited to the length of the tailpipe. The packer must not be set too close to the perforations, because pressure communication through the annulus above the packer may cause casing collapse. A safe setting depth must be selected after evaluation of the quality of the cement bond with the logs (Fig. 14-39).

Possible contamination of the cement slurry by the fluid in the hole limits the maximum spacing between the packer and the treated zone. In Fig. 14-40, the packer is set too high, allowing cement slurry to be contaminated as it channels through the mud to reach the perforations. Shryock and Slagle (1968) recommended that the retrievable packer be set no more than 25 ft [8 m] above the perforations.

6. Squeeze pressure is applied. If the high-pressure squeeze technique is used, the formation is broken down, and the cement slurry is pumped into the fracture. For low-pressure squeeze jobs, hesitation pumping begins as soon as the packer is set.

7. Pumping continues until no pressure leakoff occurs. A further pressure test of about 500 psi [3.5 MPa] more than the final injection pressure indicates the end of the injection process. Usually, a well-cemented perforation accepts a pressure above the formation fracturing pressure, but fracturing may occur if one attempts to verify such a condition.

Fig. 14-39. Squeeze job with a retrievable packer and tailpipe.

Fig. 14-40. Cement-slurry contamination (from Shryock and Slagle, 1968; reprinted with permission of SPE).
8. Pressure is bled off and returns are checked. The packer bypass is opened and excess cement is reversed out. Washing off the cement slurry in front of the perforations can be performed by releasing the packer and slowly lowering the workstring during the reversing; however, there is a danger of disturbing the unset cement filtercake.

9. Tools are retrieved, and the well is left undisturbed to allow the slurry to cure for the recommended WOC time.

When preparing the slurry, the use of a recirculating or batch mixer is strongly recommended, because it ensures that the properties of the slurry pumped in the well are close to those designed in the laboratory. On most squeeze jobs, the cement-slurry volume is small, but the quality requirements are high; therefore, special care during slurry preparation is justified.

14-14 Monitoring squeeze jobs

The typical parameters that should be monitored during the job include the following.

- Density and volume of fluids in various tanks
- Pressure, density, flow rate, and volume at pump outlet (Fig. 14-41)
- Volume and density of all fluids returned and pumped through the annulus
- Coiled tubing pressure, string weight, depth, tubing OD, and tubing cycles

During the job, these data are routinely analyzed in real time to determine the subsequent steps. The operator is limited to a few options: continue squeezing, increase squeeze pressure, or stop squeezing and start the cleanup operation.

14-15 Cleanup after a squeeze job

When perforations and casing leaks are squeezed, the excess cement remaining inside the casing may be cleaned up before it sets or drilled out after it sets. Removing the excess cement before setting provides a clear benefit in terms of cost and time; however, this procedure presents the risk of destroying the cement nodes. In all cases, a positive pressure should be maintained until the cement is fully set.

Excess cement in Bradenhead squeezes is easily cleaned up, because no hardware prevents pipe movement. To accelerate the setting of the cement nodes, Krause and Reem (1992) described a method of spotting an accelerator (triethanolamine) in front of the squeezed section after the cement is cleaned out. When a retrievable cement retainer is used in a circulation squeeze, its upper surface should be cleaned from any cement that might have fallen on top of it.

Removing excess cement when the treatment is performed with coiled tubing is more common. Different techniques are possible.

- Reverse circulate cement slurry
- Contaminate excess cement and reverse it out
- Contaminate excess cement and circulate it out directly
- Contaminate excess cement and leave it in the hole

The relative advantages and drawbacks of direct and reverse circulation (Section 14-4.3) are exacerbated because of the increased pressure drop and lower rates with coiled tubing.

During the contamination step, the coiled tubing is moved into the excess cement at a velocity adjusted to ensure a proper volume ratio between the cement and the contaminating fluid, typically 50% (see Fig. 14-36). Using a diverter or jetting tool at the tip of the tubing
enhances mixing (Walker et al., 1992). Cleanup is often performed in more than one stage. The bulk of the cement is cleaned out first. Then, another run is performed to provide a final cleaning. When the jet passes downhole hardware, the pump rate is increased to ensure the removal of cement from all surfaces.

14-16 Squeeze job evaluation
The extent to which one must evaluate the results of a squeeze job depends on the requirements of the subsequent operations to be performed on the well. As a preliminary step before an evaluation, the state of the wellbore is checked to detect the presence of cement nodes that may restrict passage of downhole tools. An underreaming operation is eventually performed. Also, the rathole is checked for the presence of cement.

14-16.1 Temperature log
When a high-pressure squeeze job is performed to ensure that a subsequent fracturing treatment will stimulate a target zone, a temperature log can locate the cement and indicate if any slurry was injected outside of the perforated interval (Krause and Reem, 1992).

Goolsby (1969) evaluated squeeze results on water injection wells by comparing pre- and postsqueeze temperature profiles. By logging the well temperature after a postsqueeze injection test, he was able to demonstrate that the well accepted the injection water at the planned location.

14-16.2 Positive and negative pressure tests
Plugged perforations are evaluated by performing a positive or negative pressure test. A positive pressure test subjects the well to a given pressure and determines whether fluid can be injected into the formation. A negative pressure test, also known as an inflow test, subjects the well to a pressure reduction and is used to determine how effectively the plugged perforations prevent the ingress of fluids from the formation. The test pressure is usually that which the well is expected to experience during injection or production; it is determined during the job-design phase (Walker et al., 1992).

The negative pressure test is performed as follows:
- placing a light brine across the perforations
- swabbing the well
- running a dry test (Fig. 14-42) (Chapter 15).

If the perforations are completely sealed, no inflow should be recorded on the test pressure chart (Fig. 14-43).
If the pressure reduction is excessive, the resulting mechanical stresses on both the cement and casing may cause the nodes to fail.

14-16.3 Acoustic logs
When the objective of the squeeze is to repair a primary cementing job, cement logs should be run to evaluate the effectiveness of the repair by comparing presqueeze and postsqueeze logs (Chapter 15).

14-16.4 Production changes
One of the most common ways to evaluate a remedial treatment is to compare the well production rates before and after the treatment (Keese et al., 2000).

14-16.5 Cement hardness
If well cleanup was not performed after the squeeze, the cement in the wellbore is drilled out. For such jobs, Suman and Ellis (1977) reported that a good indication of success is the nature of the cuttings. If the cement is hard throughout, the results are usually good. However, soft spots or voids are not necessarily indicative of a failure.

14-16.6 Radioactive tracers
Radioactive materials may be added to the cement slurry, and subsequent tracer surveys can indicate whether the cement is placed in the desired interval. The isotopes $^{131}$I, $^{192}$Ir, and $^{46}$Sc are appropriate because of their short half-lives—8 days, 75 days, and 85 days, respectively. The iridium and scandium radioisotopes are preferable, because iodine (present as iodide) is soluable and may be squeezed out of the cement with the filtrate.

14-17 Reasons for squeeze cementing failures
Whenever a squeeze treatment fails to meet its objectives, a thorough investigation must be conducted to analyze the job, understand why a failure occurred, and improve the design of subsequent treatments. Squeeze failures may originate from misconceptions of what a squeeze treatment is and what actually happens downhole.

14-17.1 Improper slurry selection
The cement slurry does not penetrate the pores of the rock. Only the mix-water and dissolved substances penetrate the pores, while the solids accumulate at the formation face and form the filtercake. It would require a permeability higher than 100 D for solids from a conventional Class C cement to penetrate a sandstone matrix. Even microfine cements have limited penetration, if any, through porous media. The only way for a slurry to penetrate a formation is through fissures, fractures, and large holes (vugs).

14-17.2 Excessive final squeeze pressure
A high final squeeze pressure does not increase the chance of success; on the contrary, it increases the chance of fracturing the formation and losing control of the cement-slurry placement. Once created, a fracture may extend across various zones, and open unwanted channels of communication between previously isolated zones. It is important that a “think downhole” attitude be developed among all personnel involved in this operation.

14-17.3 Plugged perforations
Another common misconception concerning squeeze cementing is that all perforation holes are open and receptive to fluids (Rike and Rike, 1981). Such an assumption can lead to failure. The mud filtercake, which is capable of withstanding a large differential pressure when applied from the wellbore toward the formation, cleans up easily when submitted to a differential pressure in the other direction. In addition to mudcake, debris, scale, paraffin, formation sand, pipe dope, rust, and paint can accumulate and plug the perforations. Goodwin (1984) reported that, in a producing well, the upper perforations are usually open, while the plugged perforations are generally found in the lower zones. Squeezing under such conditions will not fill all of the perforations with cement. Following the treatment, the perforations not plugged with cement will allow entry of formation fluids into the well.

Perforation washing before the squeeze job helps to render all perforations receptive to the squeeze cement slurry.
14-17.4 Improper packer location
If the packer is set too high above the perforations, the cement slurry will become contaminated as it channels through the mud or completion fluid (Section 14-13). Slurry properties such as fluid loss, thickening time, and viscosity are adversely affected by contamination, and slurry placement results are altered.

14-18 Noncementing solutions
As discussed in the introduction, there are solutions to many of the well problems described in this chapter that do not involve cementitious systems. Although they are somewhat beyond the scope of this chapter, they deserve to be mentioned briefly. Noncementing solutions include mechanical tools and noncementitious fluids. Such solutions can be classified according to their penetration into the wellbore: none, limited, and deep.

Solutions at the wellbore (no penetration) include bridge plugs or mechanical plugback tools (Chapter 11). These devices have long been used as an alternative to cement plugs for isolating bottom perforations in cased hole producers.

Limited penetration techniques include the following. A set of perforations can be plugged without plugging the entire hole by using a scab liner—a piece of liner that is cemented off-bottom (Loveland and Bond, 1996; Chapter 11). Daigle et al. (2000) presented case studies of expandable liners used to repair corroded casing. Saltel et al. (1999) described the use of an inflatable composite sleeve to plug perforations or casing leaks. The same method can be used to plug small sections of open hole. Injecting high-viscosity polymers (Irani, 1999), polymerizable resins, or other types of sealants (Rusch et al., 1999) can plug gas-migration channels behind the casing. Carpenter et al. (2001) described test results of placing a metal alloy in the annulus and fusing it to the casing. The excellent metal-to-metal bond stopped gas flow.

Deep-penetrating polymer fluids are used to control water or gas production by plugging fissures and fractures (Eaton et al., 2000). For such applications, low-viscosity solids-free systems are often used (Chan, 1989; Shelley and Sculillo, 1995; Creel and Crook, 1997). A common example is a polyacrylamide solution containing crosslinkers such as Cr<sup>3+</sup> (Lai et al., 1999) or acids (Chatterji and Borchardt, 1980). The crosslinking reaction is timed to occur after fluid placement. For such treatments, the fluid volume is based on the expected penetration, assuming a radial displacement and knowing the formation porosity and thickness from cores or logs.

Other types of treatments such as relative permeability modifiers are beyond the scope of this discussion.

14-19 Conclusions
Remedial cementing operations are often performed on short notice, leaving little time for planning and design. Consequently, the success rate is frequently low. To mitigate this problem, general best-practice guidelines based on long experience have been offered by various authors (Rike, 1973; Smith et al., 1983; Toor, 1983; Goodwin, 1984; Heathman et al., 1994; Lopez and Renshaw, 1998; Bimaputra et al., 2000). The guidelines and recommendations presented in the chapter are of little use unless all involved agree that a detailed design is required, and there is good communication to ensure that the design is executed properly.

For plug cementing, implementation of the simple techniques and guidelines discussed in this chapter improves the probability of success.

Successful squeeze cementing starts at the job-design stage. The questions in Table 14-10 must be answered before executing the operation.

One cannot be confident of job success without satisfactory answers to these questions.

There is a general consensus among the authors cited in this chapter that the most successful method is the low-pressure hesitation squeeze, with a low-fluid-loss slurry and a packer or retainer as the isolation tool. The high-pressure techniques should be applied with extreme caution.

A short summary of remedial-cementing guidelines is presented in Table 14-11, together with additional issues that are application dependent. These guidelines may also be presented in the form of a decision tree (Fig. 14-44).

14-20 Acronym list
BOP Blowout preventer
GOR Gas/oil ratio
IBOP Internal, or inside, blowout preventer
LCM Lost-circulation materials
WOR Water/oil ratio
Table 14-10. Questions Before a Squeeze-Cementing Job

<table>
<thead>
<tr>
<th>Category</th>
<th>Questions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Problem identification</td>
<td>What is the problem?</td>
</tr>
<tr>
<td></td>
<td>What are the objectives of the job?</td>
</tr>
<tr>
<td>Selection of remedial method</td>
<td>Which squeeze technique will be used?</td>
</tr>
<tr>
<td>Selection of placement method and mechanical setup</td>
<td>Which types of tools are to be used?</td>
</tr>
<tr>
<td></td>
<td>At which depth should the packer be set?</td>
</tr>
<tr>
<td></td>
<td>To which depth should the tailpipe be lowered?</td>
</tr>
<tr>
<td></td>
<td>Which well preparation technique(s) are needed?</td>
</tr>
<tr>
<td>Selection of fluid type and volume</td>
<td>Which type of fluid is in the hole?</td>
</tr>
<tr>
<td>Detailed job design</td>
<td>What will be the maximum job pressure?</td>
</tr>
<tr>
<td></td>
<td>Which job procedure will be followed?</td>
</tr>
<tr>
<td></td>
<td>What is the estimated job time?</td>
</tr>
<tr>
<td></td>
<td>What are the composition and properties of the slurry?</td>
</tr>
<tr>
<td></td>
<td>What quantity of slurry is necessary?</td>
</tr>
<tr>
<td></td>
<td>How will the perforations be opened or cleaned?</td>
</tr>
<tr>
<td></td>
<td>What is the formation breakdown pressure?</td>
</tr>
<tr>
<td></td>
<td>Have other formation data (lithology, permeability, pressure, water/oil and gas/oil contact, bottomhole temperature) been considered?</td>
</tr>
<tr>
<td></td>
<td>What is the WOC time?</td>
</tr>
<tr>
<td>Job evaluation</td>
<td>How will the job be evaluated?</td>
</tr>
</tbody>
</table>
Chapter 14 Remedial Cementing

Table 14-11. Summary of Best-Practice Guidelines for Remedial Cementing

<table>
<thead>
<tr>
<th>General guideline for all remedial jobs</th>
<th>Check slurry properties versus acceptance criteria: density, fluid loss, filtercake thickness, rheology, and thickening time.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Define job objectives</td>
<td>Circulate the hole sufficiently. Use a low-yield-point mud with low plastic viscosity. Mud density must be sufficient to control the well.</td>
</tr>
<tr>
<td>Determine root causes of the problem.</td>
<td>Batch mix the cement slurry.</td>
</tr>
<tr>
<td>Define job type and type of slurry.</td>
<td>Pump the fluid with mechanical wiper plugs between each fluid, especially for large depths.</td>
</tr>
<tr>
<td>Collect well data</td>
<td>Monitor volumes from tank level.</td>
</tr>
<tr>
<td>Caliper for cement placement depth and slurry volume. Prefer placing plugs in gauged and competent locations. If no caliper is available, volume will be increased.</td>
<td>Pull out of hole very slowly, without rotating the pipe, to prevent swabbing.</td>
</tr>
<tr>
<td>Determine fracture pressure, especially for injector wells for which it may be low.</td>
<td>If a thixotropic slurry is pumped, clean the excess before it gels. For a coiled-tubing job, overdisplace the slurry.</td>
</tr>
<tr>
<td>Clean the well</td>
<td>Contaminate excess cement with biopolymer or borax solution. Reverse circulate the contaminated slurry only if the formation will withstand the pressure. Do not disturb the cement plug during this phase.</td>
</tr>
<tr>
<td>Condition mud for optimal mud removal during cement placement.</td>
<td>Clean the drillpipe with a wiper ball after the cement.</td>
</tr>
<tr>
<td>Remove all debris, in particular from sump hole/rathole.</td>
<td>Allow a sufficient WOC time.</td>
</tr>
<tr>
<td>Design job</td>
<td>Evaluation</td>
</tr>
<tr>
<td>Set plug length between 300 and 800 ft, no less, no more.</td>
<td>Compare results with job objectives.</td>
</tr>
<tr>
<td>Determine the base for plug (if placed off-bottom)</td>
<td>Archive this information because it will be used for subsequent jobs of same type.</td>
</tr>
<tr>
<td>Prefer solid base.</td>
<td>Additional guidelines specific to kickoff and abandonment cement plugs</td>
</tr>
<tr>
<td>Consider filling entire hole with cement, several staged plugs.</td>
<td>Use high-yield-strength or thixotropic slurries.</td>
</tr>
<tr>
<td>Use viscous pill or reactive viscous pill with density halfway between mud and cement, yield point of 70 lbf/100 ft² minimum, and length of 300 ft.</td>
<td>Place the top of a kickoff plug in a softer formation. If the kickoff plug is unsuccessful, do not drill through it. First, wait a few more hours and make another attempt to sidetrack. If the second attempt is unsuccessful, set another plug using what remains of the first plug as a solid base.</td>
</tr>
<tr>
<td>If no mechanical base is possible, decrease slurry density while maintaining good mechanical strength.</td>
<td>Additional and specific guidelines for squeeze operations</td>
</tr>
<tr>
<td>If slumping is anticipated, increase plug length.</td>
<td>Problem identification</td>
</tr>
<tr>
<td>Use mud-removal rules for mud displacement.</td>
<td>Estimate the most probable situations, evaluate the response of each situation to various treatments, and select the treatment that minimizes risks of failure.</td>
</tr>
<tr>
<td>Low-density turbulent wash should be preferred. If this is not possible, use a laminar spacer with density and viscosity halfway between the mud and the cement.</td>
<td>Pretreatment</td>
</tr>
<tr>
<td>A densified cement will displace the mud more efficiently. Warning: A good spacer has a tendency to remove the mudcake, increasing the risk of differential sticking. Maintaining pipe rotation minimizes this risk.</td>
<td>Clean the perforations.</td>
</tr>
<tr>
<td>Slurry thickening time: Define temperature based on API squeeze cementing tables. Determine thickening time and compressive strength at bottomhole circulating temperature. Thickening time is based on placement time + 30 min to 1 hr (only for cement plugs).</td>
<td>Perform an injectivity test. If results are less than 1 bbl/min at 2,000 psi, inject acid.</td>
</tr>
<tr>
<td>Use ample cement volume.</td>
<td>If acids or solvent are used to increase injectivity, filter these reactive fluids.</td>
</tr>
<tr>
<td>Schedule the disposal of returned fluids and contaminated cement.</td>
<td>Execution</td>
</tr>
<tr>
<td>Prepare expected pressures vs. volume pumped diagram for real-time evaluation of job, especially for squeeze treatments.</td>
<td>Kill the well before squeezing.</td>
</tr>
<tr>
<td>Execution</td>
<td>Check potential for casing collapse when there is a packer above the squeezed perforations, a squeeze packer, cement retainer, or production packer.</td>
</tr>
<tr>
<td>Use a tailpipe with length 1.5 times the plug length (not for lost circulation plugs) to minimize the amount of mud remaining.</td>
<td>Monitor and interpret real-time data.</td>
</tr>
<tr>
<td>Use scratchers and centralizers on the tailpipe when the hole is not excessively washed out.</td>
<td>During a hesitation squeeze, if the pressure drops during a stage, another hesitation sequence should be performed.</td>
</tr>
<tr>
<td>Use a diverter and rotate pipe during cement placement to help displace the mud.</td>
<td>(continued on next page)</td>
</tr>
<tr>
<td>While cleaning the hole, use a sacrificial wiper dart to clean the drillpipe before the job. This also allows determination of the pipe volume for accurate displacement volume.</td>
<td></td>
</tr>
</tbody>
</table>

(continued on next page)
Additional specific guidelines for jobs done with coiled tubing

Monitor internal tubing volume. Use a graduated tank to monitor the volume of fluid pumped.

Perform a depth correlation to be certain of the coiled-tubing-tip location.

Monitor the pressure drop through the coiled tubing by pumping down the coiled tubing and up the annulus.

Calculate the maximum pressure for preventing tubing burst and collapse, especially when using fatigued tubing. For collapse, the maximum risk is during reverse circulation, close to the surface.

Be aware of cement-slurry shear sensitivity. Check the thickening time accordingly.

Move the coiled tubing during all phases to prevent sticking.

Bradenhead cement squeeze

Pump 300 ft (up to 30 bbl) of spacer/wash ahead of cement. Pump spacer/wash behind at volume calculated to balance.

When possible, use a cement stinger to place the balanced plug.

Place at least 300 ft of cement (500 ft is preferred).

Pull two to three stands above plug and reverse out excess.

Pump away one-third of the cement volume while monitoring for pressure increase as cement feeds into the formation.

Wait for 15 min and then pump 1/3 of volume—again while monitoring for pressure increase.

Wait 15 min and apply pressure.

If no buildup in pressure is discovered, run in two stands (or as needed) below previous calculated cement top and reverse out excess cement.

Place another balanced plug and repeat Bradenhead procedure.

Use slurry design with API/ISO fluid-loss rate <100 mL/30 min.

If planning to tack and squeeze an 11¾-in. liner, make sure there is 500 ft of liner overlap. Weld some centralizing ribs.

Non-Bradenhead cement squeeze

Pump adequate wash ahead to remove the mudcake.

Mix sufficient cement volume to place the entire volume into the formation on the first squeeze. Use excess.

Stop and wait 15 min—pump the remaining volume in the tubing and/or drillpipe while monitoring for pressure increase.

If no pressure increase is discovered, pump the remaining cement out of the tubing and reverse out to make sure there is no cement behind the workstring.

Repeat the squeeze.

Use slurry design with API/ISO fluid-loss rate <100 mL/30 min.

If planning to tack and squeeze an 11¾-in. liner, make sure there is 500 ft of liner overlap. Weld some centralizing ribs on the upper two joints of 11¾-in. casing to improve the standoff.
Fig. 14-44. Remedial cementing flowchart.
15-1 Introduction

Cement job evaluation is the process to determine whether the objectives have been reached after the cement job has been performed. No cement-job evaluation will be efficient if the objectives are not clear. While the fundamental objective is to support the casing, other objectives vary with the nature of a particular cement job.

The purpose of a primary cement sheath varies according to the casing string it supports. For a conductor casing, the main purpose of the cement job is to prevent formation erosion by stopping the circulation of drilling fluids outside the casing. Surface casings must be cemented to seal and protect water formations and help support deeper casing strings. Intermediate strings are cemented to seal abnormally pressured formations, isolate incompetent formations, and shut off lost-circulation zones. Production strings are cemented to prevent the migration of fluids in the annulus and to ensure zonal isolation. Cement also provides some corrosion protection to all of the casing strings.

For remedial cementing, the principal objectives are to improve the quality of a primary cement job, seal perforations, repair casing leaks, and isolate productive layers.

Before the development of acoustic cement logs, cement-job evaluation consisted of testing the hydraulic isolation or locating the top of the cement. This can be performed after primary cement jobs (e.g., when water zones are located near the oil or gas zone). It can also be performed after remedial cementing to test if the perforations have been effectively sealed.

The most common techniques are pressure testing and dry testing. In some areas, the cement quality is verified through a production test or communication testing through perforations.

15-2 Hydraulic testing

Hydraulic testing is a method to evaluate the isolation provided by the cement. This can be performed after primary cement jobs (e.g., when water zones are located near the oil or gas zone). It can also be performed after remedial cementing to test if the perforations have been effectively sealed.

The most common techniques are pressure testing and dry testing. In some areas, the cement quality is verified through a production test or communication testing through perforations.

15-2.1 Pressure testing

Pressure testing is the most common hydraulic testing method. It is generally performed after every surface- or intermediate-casing cement job. A casing pressure test is performed first to verify the mechanical integrity of the casing. To avoid damaging the set cement or the cement/casing bond, this should be performed soon after the top plug bumps.

After the cement sets, the casing shoe is drilled out, and the internal casing pressure is increased until the pressure at the casing shoe exceeds the pressure that will be applied at this point during the next drilling phase. A casing shoe that does not hold pressure indicates a poor cement job, and remedial cementing is required. When the pressure is raised until the formation breaks down, the test is called a pressure-integrity test (PIT) or leakoff test (Fig. 15-1). The objective of the PIT is to determine the maximum mud weight that can be used for drilling the subsequent section. Leakoff tests are most frequently performed on exploration wells. Procedures for conducting and interpreting a PIT are described by Postler (1997). The guidelines are summarized here.

1. Prepare the test: Check valves for leaks, prepare clean mud, and use a good-quality pressure gauge.
2. Perform a casing test.
3. Prepare a PIT graph.
4. Pump mud at steady rate, between 0.25 and 1 bbl/min, and plot measured pressure data on the graph.
5. Use the maximum volume line to determine whether a higher pump rate is needed.

6. When the plot deviates from the linear trend, pump a small additional amount and stop pumping.

7. Monitor pressure decline for 10–15 min.

Various patterns can be interpreted on the pressure graph. In particular, a channel in the cement may be indicated by any one of the following.

- Leakoff equivalent mud weight more than 0.5 lbm/gal below the predicted value.
- Gauge pressure at minimum horizontal stress less than half of the maximum gauge pressure.

- Shut-in pressure does not level off.

The channel is confirmed after a repeat PIT shows no improvement in the above indicators.

Eventually, corrections to the measured surface pressure can be made. For example, accounting for fluid compressibility, thermal expansion, and friction-pressure decreases allows one to derive a more accurate bottomhole pressure. However, this is not usually done for shallow-marine sediments. Zhou and Wojtanowicz (1999) developed an interpretation of PITs based on channeling between cement and formation, considering the variation of stresses during cement hydration.
15-2.2 Inflow testing

Inflow testing (also known as dry testing) is a drillstem test (DST) to assess the isolation provided by the cement. The DST is essentially the opposite of a pressure test. The pressure inside the casing is reduced, and the well is monitored to detect the ingress of formation fluids. A successful dry test shows no downhole-pressure change during the opening of the downhole valve or during the following shut-in period (Fig. 15-2).

Dry tests are particularly useful for testing the effectiveness of a cement squeeze or a cement seal at the top of the liner. The dry test can also be used to test the cement seal around the casing after perforating across an impermeable layer or drilling out the casing shoe.

15-2.3 Tests through perforations

In some areas, especially when the production interval has a low permeability, the isolation provided by the cement is evaluated after the perforation of the intervals to be produced. The well then produces through the perforations and the production is analyzed. The presence of water in the produced fluid typically indicates annular communication and the need for remedial cementing.

When cement bond logs (CBLs) show poor results or when effective isolation is required over short intervals, the casing is perforated in two different locations. A packer is set between both sets of perforations, and pressure is applied at the lower perforations. This is a communication test, as explained by Abdel-Mota’al (1983). If pressure transmission or annular transmission is observed, hydraulic isolation in the annulus is inadequate, and remedial cementing is necessary. Because many operators are reluctant to add extra perforations to a casing string, this test is rarely performed today.

15-3 Temperature, nuclear, and noise-logging measurements

15-3.1 Temperature logging

Temperature logging is often used to evaluate primary cement jobs, mainly to detect the top of the cement column. Temperature surveys are also performed to detect leaks or channeling.

Fiber optics can also be used to measure the temperature in the wellbore. The fiber is placed inside the annulus (in a control line) or inside the casing. The temperature is recorded versus time and depth. Such measurements provide valuable information regarding cement placement.

15-3.1.1 Cement hydration detector

Temperature surveys are often used to detect cement in the annulus several hours after cement placement. The exothermic cement-hydration reactions (Chapter 2) raise the wellbore temperature, resulting in a deviation from the normal temperature gradient. Figure 15-3 shows a typical temperature survey performed after a primary cement job. Such measurements are easy to perform and can accurately detect the top of the cement. When combined with hole size, volumetric calculations can be performed to determine the displacement efficiency.

Fig. 15-3. Typical temperature survey.
Field experience shows that the maximum temperature anomalies arising from cement hydration range from 10° to 40°F [18° to 72°C] and strongly depend upon the annular thickness and the thermal conductivity of the formation. The heat generated during cement hydration is also intimately related to the amount of cement and additives present in the slurry. When compared with standard cements, low-density cements containing extenders generate less heat per unit of volume. In this case, the temperature increase may not be sufficiently obvious to be detected.

Well cooling by the circulation of fluids before and during cementing also influences the kinetics of cement hydration—the longer the circulation, the lower the temperature. This leads to longer thickening times and delayed and smaller temperature increases in the well. Temperature logs may not be suitable for evaluating very long cement columns, because there may be a large temperature differential between the top and the bottom of the well; also, the cement at the top of the column may require a long time to set.

The influence of well temperature is illustrated in Fig. 15-4. For the same slurry, the heat peak is larger and sharper at higher curing temperatures. Consequently, the resulting wellbore-temperature increase may be larger in hot or deep wells. In most cases, the peak temperature is obtained 4 to 12 hr after cement placement, but the temperature will remain elevated for more than 24 hr (Suman and Ellis, 1977). For best results, the temperature survey should be run within the first 12 to 24 hr after cement placement, depending upon the thickening time and downhole conditions.

Because the amount of generated heat is related to the cement volume, the temperature increase may be greater in large annuli (e.g., in washouts) when compared to holes across homogeneous formations. In some cases, a temperature increase in a smooth hole can be caused by cement invasion into a fractured or fragile formation (Suman and Ellis, 1977). On the other hand, in narrow annuli, the heat generated during cement hydration may not be sufficient to significantly alter the wellbore-temperature profile.

15-3.1.2 Communication indicator (pump-in temperature log)

After a well has been completed, temperature logs can help assess whether channeling behind the casing is occurring because of contamination of produced fluids or fluid injection outside of the perforated interval (Bergren and Bradley, 1988; Krause and Reem, 1992). Figure 15-5 is a typical example. The first temperature survey shows the temperature profile before the injec-

---

**Fig. 15-4.** Effect of temperature on the hydration kinetics of a typical Class G cement system (15.8 lbm/gal [1,900 kg/m³]).

**Fig. 15-5.** Temperature composite profile log before cement squeeze.
tion of 80 bbl of diesel oil. The second temperature survey, run a short time after injection, shows a large temperature decrease above the perforations and temperature variations down to the oil/water contact. This may indicate communication behind the casing. Correlating these logs with other cement logs is sometimes required to fully assess the presence of channels in the cement. In such cases, remedial cementing must be performed to seal the annulus and reduce the water influx.

Most limitations of conventional temperature surveys can be overcome by installing optical temperature sensing fibers in the wellbore or in the annulus between the casing and formation (Carnahan et al., 1999). The fibers are usually protected inside a small-diameter (usually ¼-in.) tube. Carnahan et al. presented an example of a steam injection well in which the sensing fibers detected the upward migration of heated fluids above 1,200 ft and out of the intended injection interval (Fig. 15-6). A squeeze treatment was performed after careful perforating at 620–622 ft (to avoid damaging the fibers). As shown in Fig. 15-7, the fluid migration was stopped successfully.

![Fig. 15-6. Temperature profile before squeeze, indicating fluid migration above injection zone owing to poor primary cement job (from Carnahan, 1999). Reprinted with permission of SPE.](image)

![Fig. 15-7. Normal temperature profile after a block squeeze indicated fluid migration has stopped (from Carnahan, 1999). Reprinted with permission of SPE.](image)
15-3.2 Nuclear logging

Radioactive materials are frequently added to treatment fluids as tracers. This technique can be used to locate drilling mud. By detecting the presence of the radioactive material in the well returns, one can estimate circulation times. In stimulation, addition of a radioactive material to the treating fluids allows one to estimate the extent of the treatment by comparing gamma ray logs run before and after injection (Ahmed, 1989). This technique is also used in cementing, mainly to locate the top of the cement (Fig. 15-8). It is important to stress that special safety and health precautions must be taken when handling and using radioactive materials, especially for materials with long half-lives.

Kilne et al. (1986) proved that radioactive tracers can be used to perform a quantitative cement evaluation. A uniform concentration of radioactive material is added to the cement slurry. Then a spectral gamma ray log is compared with the caliper log.

Several radioactive tracers can be used in cementing. Soluble tracers (e.g., I\textsuperscript{131}) can be added to the mix water. Sand or glass beads coated with a radioactive material (e.g., Ir\textsuperscript{192}) can also be used. The standard concentration of radioactive material is about 3 mCi/m\textsuperscript{3} of mix water.

The primary criterion for selecting the radioactive tracer is its half-life. When long, the alteration to the original gamma ray signature in the formation will be for all practical purposes permanent. When short, the tracer will cease to be radioactive within a few weeks or months, and the gamma ray signature will return to its initial state.

A second selection criterion is the energy of the dominant gamma ray emitted by the tracer. When using a spectral gamma ray log, it is possible to selectively measure the radioactivity of the tracer, and the amount of radioactive matter can be significantly decreased. Table 15-1 is a list of the more common radioactive tracers, with information regarding their half-lives and gamma ray energies.

<table>
<thead>
<tr>
<th>Element Name</th>
<th>Half-Life (days)</th>
<th>Main Gamma Ray Energy (MeV)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cr\textsuperscript{51}</td>
<td>27.7</td>
<td>0.32</td>
</tr>
<tr>
<td>Fe\textsuperscript{59}</td>
<td>45</td>
<td>1.10</td>
</tr>
<tr>
<td>Br\textsuperscript{82}</td>
<td>1.5</td>
<td>0.77</td>
</tr>
<tr>
<td>I\textsuperscript{131}</td>
<td>8</td>
<td>0.36</td>
</tr>
<tr>
<td>Ir\textsuperscript{192}</td>
<td>74</td>
<td>0.32</td>
</tr>
<tr>
<td>Au\textsuperscript{198}</td>
<td>2.7</td>
<td>0.41</td>
</tr>
</tbody>
</table>

15-3.3 Boron-pulsed neutron logs

The procedure for a boron-pulsed neutron log is similar to that of the pump-in temperature log. A boron solution is injected through the perforations and a pulsed neutron log is generated. Boron absorbs neutrons very efficiently; consequently, channels in the cement sheath can be readily detected, even through two strings of casing. The method is more sensitive than the pump-in temperature log (Blount et al., 1991; Sommer and Jenkins, 1993).

15-3.4 Oxygen activation logs

Oxygen activation logging (McKeon et al., 1991; Pappas et al., 1995) is a technique that can quantify water flow behind casing. High-energy neutrons interact with oxygen nuclei in water, resulting in the emission of gamma rays. Before the well is energized with neutrons, a background gamma ray log is generated. Then, the neutron tool is activated for a very short period (1 to
15 sec), followed by a longer gamma ray acquisition period (20 to 60 sec). The flow velocity is determined from the source/detector distance and the time during which the activated water passes the detector.

15-3.5 Noise logging
Flowing fluids (gas, water, or oil) produce sound. Noise logging can be used to detect fluid flow behind the casing or fluid entry inside the wellbore. This technique can be particularly useful for identifying communication between two zones with different pore pressures. The analysis of the frequency spectrum (20 to 5,000 Hz) and the amplitude of the noise enables location and identification of flowing fluids. This technique also provides information concerning the magnitude of the communication problem. In 1973, McKinley et al. discussed cases in which noise logs could identify interzonal communication more accurately than temperature logs.

A noise log is a series of stationary noise measurements, because it is difficult to detect formation-related sounds if the tool moves continuously. As a result, this technique is marginally used in the oil field.

15-4 Acoustic logging measurements

15-4.1 Introduction
Acoustic logging is the most widely used and efficient method to evaluate cement jobs. Cement-job evaluation through acoustic-log interpretation seeks the relationship between the tool response and the quality of the cement job after a given time following cement placement. The response of acoustic tools is related to the acoustic properties of the surrounding environment (casing, cement, and formation) and the quality of the acoustic coupling between the casing, cement, and formation.

Cement is only one of many parameters that can affect the log response. The analysis of the log must be performed carefully to determine the origin of the log response. Most of the time, detailed information concerning the well geometry, formation characteristics, and cement job is required.

A fair interpretation of an acoustic log can only be made when it is possible to anticipate the log response. A valid cement-job evaluation results from analyzing discrepancies between the expected and the actual log response. Today, one can qualify and possibly quantify the results of the cement job, mainly in terms of cement quality and cement coverage.

Meaningful acoustic-log interpretation (Fig. 15-9) requires good quality control of the log, a good estimate of relevant cement properties, and knowledge of the

- well and casing
- cement-job events
- pre- and postjob well history.

In this section, each of these points will be covered in detail for sonic and ultrasonic logs.

![Acoustic log flowchart](image)

**Fig. 15-9. Acoustic log flowchart.**

15-4.2 Quality control
All acoustic logs must meet rigorous quality control standards; otherwise, they have no credibility.

15-4.2.1 Measurement repeatability
All logs should have a repeat section. A repeat section is a short log pass, generally over about 200 ft [61 m] of hole, recorded immediately before the main pass. The interval logged for the repeat section must also be part...
of the main pass, so that the two passes can be com-
pared. Both logging passes must occur under identical
conditions, including tool settings and hole conditions.
The purpose is to verify that the logging tool produces
the same reading repeatedly under the same conditions.
If the tool response is repeatable, there is no guarantee
of accuracy; however, if it is not repeatable, there is
most assuredly a problem. This verification is particu-
larly important in well logging because of the environ-
mental extremes to which the logging tool is typically
subjected and the need to assure that the time spent
logging will result in good data.

The standard of “good repeatability” depends upon
the type of tool, its operating principle, and the design.
Unlike nuclear tools, acoustic tools experience no stati-
tical fluctuation; thus, repeatability is primarily a func-
tion of tool-design quality. The conventional bond log
should exhibit a virtually identical response on the
repeat and main passes.

To maximize acoustic coupling between the casing
and the cement, some operators pressurize the casing
during the logging procedure. The sensitivity of the
acoustic measurement to changes in pressure requires
that identical pressures be established and maintained
throughout the repeat pass and the main pass.
Depending upon the equipment used to exert pressure
and maintain a wireline seal, this may not be possible.
Under such circumstances, the repeat section is invalid.
The only way to ensure that the repeat and main passes
are performed under identical conditions is to run the
logs without pressurized casing.

15-4.2.2 Calibration summary

A true calibration is made against an accepted reference
standard. It may be an industry-wide standard such as
the American Petroleum Institute (API) limestone mea-
surement for nuclear tools. Or, it may be a logging com-
pany-specific standard. At present, there is no industry
standard for sonic-tool calibration. Therefore, the term
“tool check” is more appropriate than “calibration,”
because the reference is not an industry standard.
However, the industry uses the term “calibration” for
this check. The objective of this check is to ensure that
sonic tools perform consistently over time.

To properly interpret a log, a calibration summary
should be printed. It enables the log analyst to deter-
mine if the measurement setup was correct. Without a
calibration summary, it is impossible to know exactly
what was measured and how it was measured; thus, the
log results are doubtful and interpretation may lead to
erroneous conclusions.

15-4.3 Acoustic properties

15-4.3.1 Definitions

Acoustics is the science of sound. In the context of log-
ging, it pertains to the propagation of sound waves.
Sound propagation is the periodic compression and rar-
efaction of molecules (in the case of a gas or liquid) or
the squeezing and stretching of the grain fabric (in the
case of a solid) (Fig. 15-10). When this motion occurs in
the same direction as the traveling propagation, the phe-
nomenon is called a compressional wave.

In a solid, a second type of wave—the shear wave—
can propagate. It does not exist in fluids. When a shear
wave passes through a solid, the grain-fabric vibration is
perpendicular to the direction of wave propagation. The
shear wave always travels more slowly than the com-
pressional wave. Compressional and shear wave veloc-
ities are intimately related to the elastic properties of the
material (Young’s modulus, shear modulus, and
Poisson’s ratio) and are almost independent of the fre-
quency. These elastic properties relate the stress to the
strain in the material according to Hooke’s law.

Fig. 15-10. Illustration of propagation of compressional and shear
wave modes.
In well logging, sound waves are generally characterized by their slowness \((v^{-1})\), traditionally expressed in \(\mu s/ft\) or \(\mu s/m\), which is the inverse of velocity. For a linear elastic material, the relationship between the compressional- and shear-wave velocities \((v_P, v_S)\), Young’s modulus, \(E\), and Poisson’s ratio, \(\nu\), is

\[
v_P = \left[\frac{E(1-\nu)}{\rho (1+\nu)(1-2\nu)}\right]^{\frac{1}{2}} \quad \text{and} \quad v_S = \frac{E}{2\rho (1+\nu)}^{\frac{1}{2}},
\]

(15-1)

where

\(\rho = \text{density of the material.}\)

Another type of wave that is important in cement evaluation is the plate wave, illustrated in Fig. 15-11. This wave propagates along the steel casing slightly more slowly than the compression wave in the steel, and it is the basis for the CBL (Minear and Goodwin, 1998). The velocity of the plate wave, \(v_{pl}\), is given by

\[
v_{pl} = \sqrt{\frac{E}{\rho(1-\nu^2)}}.
\]

(15-2)

Today, for cased hole-log interpretation, one is mainly interested in the propagation velocity of compressional waves. Knowledge of the compressional wave velocity through a material allows one to determine the compressional acoustic impedance \((Z)\) of this material, traditionally expressed in \(10^6 \text{ kg/m}^2/\text{s}\). This unit is also called the mega-Rayleigh (MRayl).

For a homogeneous, nondissipative medium, the acoustic impedance is given by

\[
Z = \rho v_P,
\]

(15-3)

where

\(v_P = \text{velocity of compressional wave (m/s)}\)
\(\rho = \text{density of material (kg/m}^3)\).

A sound wave loses energy as it propagates through a material. This loss of energy, called attenuation, is a characteristic of the material and increases with the frequency of the wave. No general relationship exists between attenuation and frequency. For a given frequency, attenuation is normally expressed in decibels (dB) per unit of distance.

\[
A = \frac{20}{L} \log_{10} \frac{p_x}{p_{x+L}},
\]

(15-4)

where

\(A = \text{signal attenuation (dB)}\)
\(L = \text{distance between the two locations}\)
\(p_x = \text{signal pressure (amplitude) at a location} x\)
\(p_{x+L} = \text{signal pressure (amplitude) at a location} x + L\).

### 15-4.3.2 Acoustic properties of formations

Acoustic properties of the formation influence acoustic logs. The familiar terms fast formation and slow formation refer to sound velocity. Traditionally, for cement-evaluation purposes, a formation is called “fast” when sound travels through it faster than it does along the casing (i.e., 17,000 ft/s [5,334 m/s]). Table 15-2 presents the acoustic properties of common formations.

The same table cannot be constructed for attenuation characteristics, because they are frequency dependent. Generally speaking, attenuation is high in slow formations. Attenuation is very high in unconsolidated materials (e.g., shallow sands and shales). Attenuation is negligible in strong, consolidated rocks.
15-4.3.3 Acoustic properties of cements

Cased hole acoustic-log response depends primarily upon the acoustic properties of the hard set cement. The acoustic properties of rocks are well-known and remain essentially constant during the life of a well. Unlike rocks, the acoustic properties of cements change during this time period. This fundamental difference influences the log analysis.

- Log results can change with time, because the physical properties of the cement are changing with time.
- The set cement may not be in the same physical state all along the casing string. This can produce a strong difference in the log response on long strings for which a large temperature difference exists between the bottom and top of the cement.

The acoustic properties of various cement formulations at ambient conditions are reported in Table 15-3 (Jutten et al., 1987). From these results, it appears that low-density slurries with a low solid-volume fraction have a low acoustic impedance that can change significantly after several days. The acoustic impedance of the higher-density slurries changes less than 20% between 1 and 7 days.

Cements extended with hollow microspheres or nitrogen can have a very low acoustic impedance. As a result, it may be difficult to distinguish the cement from water. Significant improvement of the response over days or even weeks has sometimes been observed when running time-lapse logs. This has usually been attributed to the evolution of the cement acoustic impedance with time. Such fluctuations often originate from overestimation of the bottomhole circulating temperature, resulting in slurry overretardation. Fluctuations may also occur when the temperature variation along a long cement column is ignored.

### Table 15-2. Acoustic Properties of Common Formations

<table>
<thead>
<tr>
<th>Material Type</th>
<th>Δt (μs ft⁻¹)</th>
<th>Sound Velocity (ft/s [m/s⁻¹])</th>
<th>Acoustic Impedance (MRayl)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Nonporous Solids</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Steel (compression wave)</td>
<td>51.4</td>
<td>19,450 [5,930]</td>
<td>46.00</td>
</tr>
<tr>
<td>Plate wave in casing (CBL)</td>
<td>57.0</td>
<td>17,500 [5,334]</td>
<td>41.60</td>
</tr>
<tr>
<td>Dolomite</td>
<td>43.5</td>
<td>23,000 [7,010]</td>
<td>20.19</td>
</tr>
<tr>
<td>Anhydrite</td>
<td>50.0</td>
<td>20,000 [6,096]</td>
<td>18.17</td>
</tr>
<tr>
<td>Limestone</td>
<td>47.6</td>
<td>21,000 [6,400]</td>
<td>17.34</td>
</tr>
<tr>
<td>Calcite</td>
<td>49.7</td>
<td>20,100 [6,126]</td>
<td>16.60</td>
</tr>
<tr>
<td>Quartz</td>
<td>52.9</td>
<td>18,900 [5,760]</td>
<td>15.21</td>
</tr>
<tr>
<td>Gypsum</td>
<td>52.6</td>
<td>19,000 [5,791]</td>
<td>13.61</td>
</tr>
<tr>
<td>Halite</td>
<td>66.6</td>
<td>15,000 [4,572]</td>
<td>9.33</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Material Type</th>
<th>Porosity (%)</th>
<th>Δt (μs ft⁻¹)</th>
<th>Sound Velocity (ft/s [m/s⁻¹])</th>
<th>Acoustic Impedance (MRayl)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Water-Saturated Porous Rock</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Dolomite</td>
<td>5 to 20</td>
<td>50.0 to 66.6</td>
<td>20,000 to 15,000 [6,096 to 4,572]</td>
<td>16.95 to 11.52</td>
</tr>
<tr>
<td>Limestone</td>
<td>5 to 20</td>
<td>54.0 to 76.9</td>
<td>18,500 to 13,000 [5,639 to 3,962]</td>
<td>14.83 to 9.43</td>
</tr>
<tr>
<td>Sandstone</td>
<td>5 to 20</td>
<td>62.5 to 86.9</td>
<td>16,000 to 11,500 [4,877 to 3,505]</td>
<td>12.58 to 8.20</td>
</tr>
<tr>
<td>Sand</td>
<td>20 to 35</td>
<td>86.9 to 111.1</td>
<td>11,500 to 9,000 [3,505 to 2,743]</td>
<td>8.20 to 6.0</td>
</tr>
<tr>
<td>Shale</td>
<td>–†</td>
<td>58.8 to 143.0</td>
<td>17,000 to 7,000 [5,181 to 2,133]</td>
<td>12.0 to 4.3</td>
</tr>
</tbody>
</table>

† Not available.
15-4.3.4 Acoustic properties of fluids

An accurate knowledge of logging-fluid properties is vital for ultrasonic cement evaluation (Section 15-4.5.6). Information concerning other fluids that may be encountered in the annulus is also important. Table 15-4 lists the properties of some homogeneous fluids, brines, and oils. The acoustic impedance of a homogeneous fluid can be calculated using Eq. 15-3.

At ultrasonic frequencies, the acoustic properties of weighted drilling muds containing suspended solid particles depend on inertial and viscous effects. Laboratory measurements shown in Table 15-5 (Hayman, 1989) have shown that the effective density measured by the ultrasound can be as much as 20% less than the static density.

### Table 15-3. Acoustic Properties of Various Cement Formulations

<table>
<thead>
<tr>
<th>Slurry Type</th>
<th>Density (lbm/gal [kg/m³])</th>
<th>Time (days)</th>
<th>Sound Velocity in Cement (m/s)</th>
<th>Acoustic Impedence (MRayl)</th>
<th>Change in Acoustic Impedence Over 1 Day (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Neat Class G</td>
<td>15.8 [1.89]</td>
<td>1</td>
<td>3,000</td>
<td>5.68</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2</td>
<td>3,250</td>
<td>6.16</td>
<td>8</td>
</tr>
<tr>
<td></td>
<td></td>
<td>7</td>
<td>3,400</td>
<td>6.44</td>
<td>13</td>
</tr>
<tr>
<td>Class G + latex + hollow silica microspheres</td>
<td>11.2 [1.34]</td>
<td>1</td>
<td>1,650</td>
<td>2.21</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2</td>
<td>2,200</td>
<td>2.95</td>
<td>33</td>
</tr>
<tr>
<td></td>
<td></td>
<td>7</td>
<td>2,500</td>
<td>3.36</td>
<td>52</td>
</tr>
<tr>
<td>Class G + soluble silicate extender</td>
<td>12.0 [1.44]</td>
<td>1</td>
<td>1,600</td>
<td>2.30</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2</td>
<td>1,750</td>
<td>2.52</td>
<td>9</td>
</tr>
<tr>
<td></td>
<td></td>
<td>7</td>
<td>2,000</td>
<td>2.88</td>
<td>25</td>
</tr>
<tr>
<td>Class G + hollow silica microspheres + 4% CaCl₂ (BWOC)</td>
<td>12.0 [1.44]</td>
<td>1</td>
<td>2,600</td>
<td>3.74</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2</td>
<td>2,800</td>
<td>4.03</td>
<td>8</td>
</tr>
<tr>
<td></td>
<td></td>
<td>7</td>
<td>3,000</td>
<td>4.32</td>
<td>16</td>
</tr>
<tr>
<td>Class G + soluble silicate extender</td>
<td>13.3 [1.59]</td>
<td>1</td>
<td>1,750</td>
<td>2.79</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2</td>
<td>2,200</td>
<td>3.51</td>
<td>26</td>
</tr>
<tr>
<td></td>
<td></td>
<td>7</td>
<td>2,500</td>
<td>3.99</td>
<td>43</td>
</tr>
<tr>
<td>Class G + latex</td>
<td>15.8 [1.89]</td>
<td>1</td>
<td>2,900</td>
<td>5.49</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2</td>
<td>3,150</td>
<td>5.97</td>
<td>9</td>
</tr>
<tr>
<td></td>
<td></td>
<td>7</td>
<td>3,350</td>
<td>6.35</td>
<td>16</td>
</tr>
<tr>
<td>Class G + 18% NaCl (BWOW)</td>
<td>16.1 [1.93]</td>
<td>1</td>
<td>2,850</td>
<td>5.50</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2</td>
<td>3,200</td>
<td>6.18</td>
<td>12</td>
</tr>
<tr>
<td></td>
<td></td>
<td>7</td>
<td>3,375</td>
<td>6.51</td>
<td>18</td>
</tr>
<tr>
<td>Class G + hematite weighting agent</td>
<td>19.0 [2.28]</td>
<td>1</td>
<td>3,300</td>
<td>7.59</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2</td>
<td>3,400</td>
<td>7.74</td>
<td>2</td>
</tr>
<tr>
<td></td>
<td></td>
<td>7</td>
<td>3,530</td>
<td>8.04</td>
<td>6</td>
</tr>
<tr>
<td>36% quality foam</td>
<td>10.0 [1.20]</td>
<td>7</td>
<td>2,300</td>
<td>2.76</td>
<td>–§</td>
</tr>
<tr>
<td>Conventional low-density system</td>
<td>12.51 [1.50]</td>
<td>7</td>
<td>2,000</td>
<td>3</td>
<td>–</td>
</tr>
<tr>
<td>Engineered-particle-size low-density system</td>
<td>10.0 [1.20]</td>
<td>7</td>
<td>2,900</td>
<td>3.48</td>
<td>–</td>
</tr>
<tr>
<td>Engineered-particle-size ultralow-density system</td>
<td>8.61 [1.03]</td>
<td>7</td>
<td>2,790</td>
<td>2.87</td>
<td>–</td>
</tr>
</tbody>
</table>

† By weight of cement
‡ By weight of water
§ Not available.
The impedance of a weighted mud is given by

\[ Z_{\text{mud}} = B \times \rho_{\text{mud}} \times v_{\text{mud}}, \]  

(15-5)

where

- \( B \) = correction factor (usually between 0.8 and 1.0)
- \( v_{\text{mud}} \) = acoustic velocity through the mud
- \( Z_{\text{mud}} \) = acoustic impedance
- \( \rho_{\text{mud}} \) = static mud density.

Figure 15-12 shows a semiempirical approximation for \( B \) that depends on the solid and liquid densities and volume fractions. Proprietary software from the logging company can be used to calculate fluid properties, including the \( B \) factor.

The attenuation of ultrasound in a weighted mud is sometimes a limiting factor in the use of ultrasonic techniques. The attenuation increases with increasing frequency and with increasing solid content (or density). OBMs usually have greater attenuation than WBMs of the same density. The attenuation is difficult to predict accurately; it depends on mud composition, temperature, and pressure.

---

### Table 15-4. Acoustic Properties of Various Homogeneous Fluids

<table>
<thead>
<tr>
<th>Material</th>
<th>Density (lbm/gal [kg/m³])</th>
<th>Slowness (µs/ft)</th>
<th>Velocity (ft/sec [m/sec])</th>
<th>Acoustic Impedance (MRayl)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water</td>
<td>8.33 [998]</td>
<td>206</td>
<td>4,860 [1,482]</td>
<td>1.48</td>
</tr>
<tr>
<td>Water + 10% NaCl</td>
<td>8.98 [1,075]</td>
<td>193</td>
<td>5,180 [1,580]</td>
<td>1.70</td>
</tr>
<tr>
<td>Water + 25% NaCl</td>
<td>9.90 [1,186]</td>
<td>175</td>
<td>5,710 [1,740]</td>
<td>2.06</td>
</tr>
<tr>
<td>Water + 36% CaCl₂</td>
<td>11.3 [1,350]</td>
<td>170</td>
<td>5,870 [1,790]</td>
<td>2.42</td>
</tr>
<tr>
<td>Water + KCl</td>
<td>9.18 [1,100]</td>
<td>189</td>
<td>5,280 [1,610]</td>
<td>1.77</td>
</tr>
<tr>
<td>Water + 58% CaBr₂</td>
<td>15.2 [1,824]</td>
<td>179</td>
<td>5,580 [1,700]</td>
<td>3.10</td>
</tr>
<tr>
<td>Sea water</td>
<td>8.56 [1,025]</td>
<td>199</td>
<td>5,020 [1,531]</td>
<td>1.57</td>
</tr>
<tr>
<td>Kerosene</td>
<td>6.74 [808]</td>
<td>230</td>
<td>4,340 [1,324]</td>
<td>1.07</td>
</tr>
<tr>
<td>Diesel</td>
<td>7.09 [850]</td>
<td>221</td>
<td>4,530 [1,380]</td>
<td>1.17</td>
</tr>
<tr>
<td>Air at 15 psi, 32°F [0°C]</td>
<td>0.01 [1.3]</td>
<td>920</td>
<td>1,090 [331]</td>
<td>0.0004</td>
</tr>
<tr>
<td>Air at 3,000 psi, 212°F [100°C]</td>
<td>1.59 [190]</td>
<td>780</td>
<td>1,280 [390]</td>
<td>0.1</td>
</tr>
</tbody>
</table>

### Table 15-5. Acoustic Properties of Various Drilling Muds

<table>
<thead>
<tr>
<th>Material</th>
<th>Density (lbm/gal [kg/m³])</th>
<th>Slowness (µs/ft)</th>
<th>Velocity (ft/sec [m/sec])</th>
<th>Acoustic Impedance (MRayl)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Low Frequency</td>
</tr>
<tr>
<td>WBM†</td>
<td>12.6 [1,510]</td>
<td>215</td>
<td>4,660 [1,420]</td>
<td>2.14</td>
</tr>
<tr>
<td>WBM</td>
<td>15.4 [1,850]</td>
<td>216</td>
<td>4,630 [1,410]</td>
<td>2.60</td>
</tr>
<tr>
<td>Oil-base fluid</td>
<td>7.79 [933]</td>
<td>231</td>
<td>4,330 [1,320]</td>
<td>1.23</td>
</tr>
<tr>
<td>OBM‡</td>
<td>12.6 [1,510]</td>
<td>245</td>
<td>4,070 [1,240]</td>
<td>1.87</td>
</tr>
</tbody>
</table>

† Water-base mud
‡ Oil-base mud
Chapter 15 Cement Job Evaluation

15-4.4 Sonic cement evaluation techniques

15-4.4.1 History

Cement bond logging was developed in the late 1950s and is still widely used to evaluate cement jobs. Its use can be traced to 1960, when Tixier et al. found that the transit-time curve on openhole sonic logs often “cycle skipped” when run inside the casing because of considerable attenuation of the acoustic signal.

In 1961, two major service companies published the results of laboratory and field testing of tools designed to measure the actual amplitude of the acoustic signal (Grosman, et al., 1961; Anderson and Walker, 1961). One company reported that more than 500 CBLs had been run between April 1959 and November 1960 in North and South America. Both observed many of the interpretation complexities still discussed today, such as those linked to cement-sheath thickness, pipe eccentricity, bond to pipe versus bond to formation, and fast formation (Section 15-4.4.2.4).

In 1962, Winn et al. reported the results of a laboratory study concerning the effect of various cement compositions on the attenuation of a sonic signal and compared the acoustic measurement to hydraulic communication. In 1963, Bade reported a field study involving approximately 250 CBLs run in the Williston Basin of central North America. Four commercially available tools were used. Bade observed the need for proper centralization as well as the need for taking measurements within short time intervals (known as gates) to exclude the formation signals. In 1963, Pardue et al. provided cement-to-log measurement correlations that are still used in interpretation charts, along with a theoretical model employing a thin steel plate coupled to an infinite half-space. Also in 1963, Pickett argued for some form of full-waveform presentation on both openhole and cased hole CBL logs. Using data from Bade’s field study, Pickett showed the wide variation in amplitude measurements when various gate settings were used and suggested the need for some kind of waveform presentation to eliminate these ambiguities.

In 1964, Carter and Evans provided information from experiments on the pipe-to-cement bond, with consideration given to casing-surface finishes, cement placement techniques, and the timing of operations in the cemented casing. In a paper directed primarily at formation evaluation, Anderson and Riddle (1964) pointed out the efficacy of a direct attenuation measurement using two receivers in place of a single-receiver amplitude measurement. In 1968, Walker presented an overview of the CBL and the economic considerations in the decision on whether to run one. Brown et al. (1970) showed the advantages to be gained from a shorter spacing between the transmitter and receiver for both amplitude measurements and full-waveform measurements. They suggested 3 ft [0.9 m] and 5 ft [1.5 m], respectively, as good compromises.

A paper published in 1974 by Fertl et al. was oriented toward operational considerations: It included a checklist and descriptions of tool-design differences and their resulting effects on the log. The authors lauded the potential of the bond-log measurement and lamented the lack of standardization.

A resurgence of CBL-related research occurred in the 1980s. McGhee and Vacca (1980) summarized the possible causes of a microannulus and emphasized the importance of dealing with a microannulus if it should occur. In 1982, Gollwitzer and Masson presented the justification for a borehole-compensated CBL that directly measured attenuation by employing multiple receivers in the logging sonde. In 1983, Bruckdorfer et al. extended the available empirical correlations between cement compressive strength and the CBL attenuation rate to include foamed cements.

In 1984, Nayfeh et al. published the results of an experimental and numerical study of the effects of wellbore fluids on CBL amplitude measurements. Considerable differences in free-pipe amplitude were shown to occur for various brines. Pressure and temperature corrections were given for the transducers used in CBL tools. In 1985, Allen and Wood offered a solution to the operational problem of assuring that the amplitude measurement gate is correctly set by proposing the simultaneous recording of sliding and fixed-gate CBL amplitudes (Section 15-4.4.2.5). In 1985, Bigelow presented a comprehensive guide to CBL interpretation, with an emphasis on qualitative interpretation of the full-waveform presentation based on understanding the basic acoustic processes involved and the cement job/well completion history. Bigelow emphasized the need for intelligent interpretation. Tubman et al. (1986) provided a theoretical foundation for the response of acoustic logs in cased boreholes.

In 1989, Lester developed a new cement-sheath evaluation tool featuring pad-mounted acoustic transducers. This technique provides compensated attenuation measurements within 6 distinct 60° sectors. The operating frequency is 100 kHz.

In 2000, Frisch et al. proposed a new interpretation technique that utilizes both CBL and ultrasonic data to evaluate cements. This technique uses statistical analysis to compute a CBL variance that allows differences between free, partially bonded, and bonded pipe. Statistical approaches are described later in this chapter.

A variable-density log (VDL), or presentation of the acoustic waveform at a receiver of a sonic or ultrasonic measurement, is commonly used as an adjunct to the CBL and offers better insights into its interpretation.

**15-4.4.2 The CBL**

15-4.4.2.1 Description of the conventional bond-logging tool

Figure 15-13 shows a schematic diagram of a representative bond-log tool, together with a cross section of a cased and cemented well. The tool has an acoustic transmitter that is usually made of a piezoelectric ceramic. There are two receivers, also of piezoelectric ceramics, in most tools. Some designs incorporate a single receiver. In the former case, the two receivers are generally located 3 ft [0.9 m] and 5 ft [1.5 m] from the transmitter. In the latter, the single receiver is 4 ft [1.2 m] from the transmitter. Some hostile-environment tools use magnetorestrictive transducers rather than those made of ceramics. This requires different pressure and temperature corrections (Nayfeh et al., 1984). Not shown in the figure, but required adjuncts for the tool, are a sufficient number of centralizers to ensure that the transmitter/receiver section of the tool remains centered in the pipe.

15-4.4.2.2 Acoustics of the bond-log measurement

The transmitter repeatedly emits short bursts of acoustical energy. The duration of each burst is about 50 μs, and the repetition rate is between 10 and 60 Hz, depending upon the particular tool design (or a frequency selected by the logging engineer, in some cases). The frequency of each sonic burst is about 20 kHz for larger-diameter tools (larger than 3 in. [8 cm]) and about 30 kHz for smaller-diameter tools (less than 2 in. [5 cm]). One company offers a tool with a frequency of 12 kHz. In the time interval between transmitter bursts, the receiver picks up the signal and makes the bond-log measurements. Most of the signal of interest arrives at the receiver between 1 and 2 ms after the transmitted burst.

The transmitter burst creates an approximately spherical wave front that expands away from the tool in all directions. As the wave front strikes the inside wall of the casing, it is refracted according to Snell’s law. There is one particular direction of travel of the wave front that will result in refraction straight down the casing. Known as the critical angle, it is about 16.5° with fresh water in the hole. The portion of the wave front that is refracted straight down the pipe ultimately determines the amplitude and transit-time measurements that appear on the log. Some parts of the original wave front travel directly through the mud, and some parts refract their way into the annulus and formation. Part of the latter ultimately shows up at the receiver as a formation signal and the former shows up as mud waves.
Figure 15-14 is a schematic representation of the various paths the original burst can follow and still arrive at the receiver. The waveforms in the figure are meant to convey the relative times of arrival of the acoustic energy that has traveled along the various paths. The wave that refracted directly down the casing wall usually arrives first because of the high sound velocity in steel and the relatively short distance. The mud wave has the shortest distance to travel; however, because of the low sound velocity in fluids, it arrives very late. The arrival time of the shear and compressional formation waves is highly variable (Section 15-4.4.2.5). The signal arriving at the receiver will be a mixture, or composite, of waves from all these paths. The interpretation of the actual bond-log measurement (as opposed to a picture of the entire composite wave itself) depends upon the casing wave arriving before anything else.

The casing wave is the portion of the original acoustic burst that propagates directly down the casing wall. It loses energy to the annulus and borehole as it propagates, owing to shear coupling with the adjacent materials. The greater the shear coupling, the greater the energy lost into the adjacent materials. The loss to the formation is low and constant; therefore, the loss to the annulus is the variable. The magnitude of the loss is represented by the amplitude or attenuation appearing on the log. If there is fluid in the annulus, there will be little attenuation of the casing signal. In fact, all fluids would be expected to look alike because there is no shear coupling for any fluid. This is also the reason that even a microscopic gap of a few thousandths of an inch between the pipe and a cement sheath, known as a microannulus, has a strong effect on the signal (Section 15-4.4.2.13).

15-4.4.2.3 Description of the full acoustic wave display: VDL

The presentation of the full waveform provides some information about the cement job. The actual composite signal is presented in Fig. 15-15. While its use in bond-log interpretation is primarily qualitative, it contains all of the available information in picture form.

There are two ways to present or display this signal on the log itself. One way is to display an actual waveform. The disadvantage of this approach is that one does not see a continuous display with depth; instead, one waveform for every 2 to 4 ft [0.6 to 1.2 m] is presented. Consequently, this presentation is rarely seen today.

![Fig. 15-14. Sonic-wave paths.](image)
The other presentation is the variable intensity display, in which the amplitudes of the waveforms are converted to a gray or color scale. Figure 15-15 is an illustration of how the amplitude information is transformed to the intensity information. An amplitude of zero is displayed as medium gray. Positive amplitudes become blacker as they increase. Negative amplitudes become whiter as they decrease. Continuous and discrete (five-level) intensity scales are used in the industry. The color display uses a spectrum. The minimum amplitude (negative) is displayed as dark blue, the maximum amplitude (positive) is red, and zero amplitude is green. This display is continuous with depth and easy to read. However, the resolution depends upon the dynamic range of the received signals. A VDL example is shown in Fig. 15-16.

In multiple-receiver tools, the full-wave display generally comes from the 5-ft [1.5-m] spaced receiver. Increasing the spacing between the transmitter and receiver is advantageous, because the various constituents of the composite wave (casing, formation compressional, and formation shear) are spread apart. As the distance increases, the velocity differences become more pronounced. However, increasing the spacing can be problematic because the received wave is more attenuated; thus, a compromise is necessary. Because the full-wave display is used qualitatively in most cases, the very high attenuation at 5 ft [1.5 m] is not a problem, because the qualitative characteristics are still distinct.
### Fig. 15-16.

Full acoustic-wave display (CBL amplitude and VDL).

#### PIP Summary

- **Time mark every 60 s**
- **Casing collars**
- **Cement isolation marker**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Min.</th>
<th>Amplitude</th>
<th>Max.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transit Time (Sliding Gate) (TTSL)</td>
<td>400</td>
<td>200</td>
<td></td>
</tr>
<tr>
<td>Transit Time (TT)</td>
<td>200</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gamma Ray (GR)</td>
<td>0</td>
<td>150</td>
<td></td>
</tr>
<tr>
<td>CCL (CCLU)</td>
<td>-1</td>
<td>1</td>
<td></td>
</tr>
</tbody>
</table>

| Tension (TENS) (lbf)          | 2,000| 0         | 50   |
| CBL Amplitude (CBL)           | 0    | 50        |      |
| Variable Density Log (μs)     | 200  | 1,200     |      |

---

*Chapter 15 Cement Job Evaluation*
15-4.4.2.4 CBL/VDL: Qualitative interpretation

The analysis of the full wave display gives only qualitative information about the cement job. If the cement-to-casing bond is good, most of the sonic energy will leave the casing and pass into the cement; thus, the casing waves will have a low amplitude. Likewise, if the cement-to-formation bond is good, the energy will go through the cement into the formation. The sonic waves (compressional and shear) will then propagate and attenuate through the formation. Because formations are never perfectly homogeneous, their acoustic properties vary.

Wavy patterns on the received waveforms are the perfect illustration of this. They represent a qualitative indication of good acoustic coupling between the cement and formation (Fig. 15-17).

Several special cases should be taken into consideration.

*Unconsolidated formations:* These shallow formations strongly attenuate the sound. The VDL does not show any formation waves because their amplitude is too low.

![Formation arrivals: wavy patterns](image-url)

**Fig. 15-17.** Wavy patterns on the VDL represent formation arrival. In this particular example, the absence of a casing arrival and the low CBL amplitude are indicative of good acoustic coupling between the cement and the casing.
Fast formations are those through which sound travels faster than along the casing. The wavy pattern on the VDL is seen earlier than the casing arrivals. Obviously, both the casing-to-cement bond and the cement-to-formation bond are generally good.

Salt formations, which are highly plastic, have little heterogeneity. Across such a zone, the VDL is very regular most of the time, sometimes appearing similar to that of free pipe.

Concentric casings: If the inner casing is well cemented, the VDL will show the quality of the previous cement job but often displays parallel stripes as in free pipe. The chevron patterns at the casing collars are visible. When the annular gap between both casings is well cemented, the casing collars from the previous casing can also be seen on the VDL. Often in this type of situation, an apparent frequency increase is seen on the signal, which is visualized on the VDL by a larger number of thinner black-and-white stripes (Jutten, 1988).

Intimate contact between the casing and formation: When the casing is lying against the formation wall, even when it is not well cemented, formation arrivals may be seen on the VDL. The casing signals are also very strong.

15-4.4.2.5 Quantitative data from the acoustic wave
The first few cycles of the received waveform are shown in stylized form in Fig. 15-18. The traditional convention in acoustic logging is to label the half-cycles as \( E_1, E_2, E_3, \) etc., with odd numbers referring to positive peaks and even numbers to negative peaks. Ideally, the first cycles are from casing signal. In the case of free pipe (i.e., a fluid-filled annulus) this is true, but in cemented pipe the picture is not so clear, because it depends on the formation properties and the thickness of the cement sheath (Section 15-4.4.2.10).

The underlying premise in quantitative bond logging is that the strength of the casing signal is a function of the material adjacent to the casing. From this premise, and the considerations in the preceding paragraph, it follows that the earliest detectable wave, \( E_1 \), should be measured. However, this is not the first arrival because it is preceded by a much smaller single-cycle precursor. Many schemes have been implemented to quantify the strength of the casing signal, including measuring the peak amplitudes of \( E_1, E_2, \) and \( E_3 \), the area under the half-cycles, and the area under multiple half-cycles (Bade, 1963; Pickett, 1963). For this reason, the log curves generated by different tool designs in the same well at the same time can look completely different. Because there is no analytical description of the received waveform in terms of the geometry and physical parameters, there is no definitively correct measurement scheme to be applied to the waveform. However, laboratory work by Jutten and Parcevaux (1987) and Jutten and Corrigall (1988) indicated that even the tail end of the \( E_1 \) half-cycle may be affected by the well geometry. Therefore, measuring the amplitude of \( E_1 \) is necessary.

The first quantitative measurement performed on the full wave is the elapsed time between the transmitter firing and the arrival of the first part of the wave exceeding a preset amplitude threshold (Fig. 15-19). It is known as the transit time. The actual measurement value depends on (1) the threshold level and (2) the use of positive or negative peaks.

The time measured will also depend on the size of the inside diameter of the casing and the outside diameter (OD) of the tool, as well as the speed of sound in the borehole fluid. Because of the threshold amplitude (necessary to avoid random noise), the measured time will increase slightly as the amplitude of the relevant half-cycle (\( E_1 \) in Fig. 15-19) drops close to the threshold level.
(also known as the detection level or bias level). When the amplitude drops below the threshold, the arrival time of the next half-cycle will be measured, e.g., $E_3$. Thus, the transit-time measurement responds to changes in amplitude in a crude way. It is sometimes mistakenly assumed that the transit-time curve says something about the cement. In fact, the most valuable (and essential) function of the transit-time curve is quality control (Section 15-4.4.2.9). As long as the amplitude is well above the threshold level (usually on the order of 5 mV), the transit-time curve is a highly sensitive measure of tool centering in the pipe.

The second quantitative measurement is the wave amplitude from which a quantitative cement evaluation can be made. Because the arrival time of the peaks is related both to the geometry of the CBL tool and the casing and to the wellbore fluid properties, the amplitude measurement can be made in two ways—using a fixed gate or a sliding gate. The technique commonly employed today is to position a fixed gate (or time interval) during which the wave amplitude is measured, preferably an $E_1$ half-cycle. For example, as shown in Fig. 15-20, the time interval is held constant relative to the moment the transmitter is fired. To ensure precise placement of this time window over the desired part of the wave, the gate is set in the well to be logged using the least-bonded pipe to be found. Note, however, that the gate must be reset for changes in pipe size and even fine-tuned for changes in pipe weight. The correct setting of the gate is a crucial step in obtaining a valid bond-log amplitude curve.

When a sliding gate is used, the CBL curve shows the maximum amplitude measured within a time interval positioned immediately after the detection of a signal larger than a preset detection level. The measurement is quantitatively useful only when that first half-cycle is measured. However, this is not the case when the amplitude of the actual casing signal falls below the bias setting (detection level) of the sliding gate. Because this technique appears to be obsolete as a primary means of measuring amplitude and although its use was proposed (Allen and Wood, 1985) to verify the positioning of the fixed gate, it will not be considered further here.

15-4.4.2.6 CBL attenuation rate

Many parameters have an influence on the amplitude measurement: calibration of the logging tool, centering of the tool, pressure, temperature, wellbore fluid, casing size and thickness, cement thickness, microannulus presence and size, and the spacing between transmitter and receiver. To reduce the measurement sensitivity and quantify the results as a function of the cement, it is necessary to speak in terms of the attenuation rate.

A theoretical expression of the CBL attenuation rate was first given by Pardue et al. in 1963. It showed that, for a thin, flat plate surrounded by a solid or a liquid, the attenuation rate can be approximated by the following equation.

$$\alpha = \frac{52.2 \left( \frac{\rho_2}{\rho_1} \right)}{h \left[ \left( \frac{v_{pl}}{v_P} \right)^2 - 1 \right]^{0.5} + \left[ \left( \frac{v_{pl}}{v_S} \right)^2 - 1 \right]^{0.5}}.$$  \hspace{1cm} (15-6)

where

- $h$ = thickness of plate (in.)
- $v_P$ = compressional wave velocity in annular material
- $v_{pl}$ = wave velocity in plate
- $v_S$ = shear wave velocity in annular material
- $\alpha$ = attenuation rate (dB/ft)
- $\rho_1$ = density of plate
- $\rho_2$ = density of annular material.

This formula shows the following.

- The primary cement variable affecting attenuation is the wave velocity.
- The attenuation is inversely proportional to the casing-wall thickness and proportional to the cement density.
- The attenuation is independent of the frequency.
- Shear coupling is required at the casing-cement interface to produce full attenuation.

Equation 15-6 ignores the effects of plate curvature, the fluid within the pipe, and the thickness of the cement sheath.
The CBL attenuation rate can also be calculated from two amplitude measurements of the same transmitted signal made by two different receivers, according to the following formulas.

\[
\alpha = -\frac{20}{L} \log_{10} \left( \frac{E_1^2}{E_1^1} \right),
\]

(15-7)

where

\[(E_1^1) = \text{amplitude of } E_1 \text{ at Receiver 1}\]
\[(E_1^2) = \text{amplitude of } E_1 \text{ at Receiver 2}\]
\[L = \text{distance (spacing) between Receivers 1 and 2 (ft)}.\]

In the case of tools with a single receiver, an approximate attenuation rate can still be computed using the following expression.

\[
\alpha = -\frac{20}{L} \log_{10} \left( \frac{E_1}{E_{fp}} \right),
\]

(15-8)

where

\[E_1 = \text{amplitude of } E_1\]
\[(E_{fp}) = \text{amplitude of } E_1 \text{ in free pipe}\]
\[L = \text{spacing between transmitter and receiver (ft)}.\]

This last expression, although still sensitive to tool calibration and wellbore parameters (it requires the free-pipe reading in millivolts), can be used.

To improve the accuracy of the attenuation-rate determination, special CBL sondes have been developed with two transmitters and two or three receivers (Fig. 15-21). The general principle is the same as a conventional CBL, but the design allows computing a bottomhole-compensated attenuation rate on which many environmental effects (e.g., pressure, temperature, wellbore fluid characteristics) have almost no effect (Gollwitzer and Masson, 1982).

Four amplitude measurements are required. The upper and lower transmitters are separated by 5.8 ft [1.8 m], and the three receivers are placed at 0.8 (short), 2.4 (near), and 3.4 ft (far) [0.2, 0.7, and 1.0 m, respectively] from the upper transmitter. The measurements made at 2.4- and 3.4-ft spacing are used to compute the bottomhole-compensated attenuation rate, which is quasi-independent of temperature and pressure.

\[
\alpha_{BHC} = \frac{-10}{L_2 - L_1} \log_{10} \left( \frac{A_{22} \times A_{21}}{A_{12} \times A_{21}} \right),
\]

(15-9)

where

\[A = \text{amplitude}\]
\[A_{ij} = p_i S_j \times 10^{-\frac{\alpha_{BHC}}{20}}\]

Early experiments (Grosmanagin et al., 1961) found that the attenuation rate is linearly related to the percentage of the casing circumference bonded by the cement (Fig. 15-22). These experiments were made with 5.5-in. diameter casings and a 25-kHz source. The bond index (BI) was derived from this concept (Pardue et al., 1963). Its validity was later extended by Jutten and Parcevaux (1987) to the percentage of bonded cemented area, regardless of the shape of the noncemented area and the nature of the fluid behind the casing. The Jutten and Parcevaux experiments used a 4.5-in. casing and 17-kHz transducers. The BI, symbolized by \(I_{bond}\), requires knowledge of the log response in the well-cemented section, which is used as a reference for the computation of the attenuation corresponding to 100% cementation (\(\alpha_{100\%cem}\)).
where $\alpha$ is the CBL attenuation rate, and $\alpha_{fp}$ is the CBL attenuation rate with free pipe.

In 1992, Gai and Lockyear claimed that the conventional BI calculation does not have correct theoretical grounds or physical intuition. Based on theory, laboratory experiments (in 7-in. casing) and case studies, these authors proposed that the correlation between the percentage bonding (BPI, symbolized by $I_{\%bond}$) and the CBL amplitude ($E_{1}$ peak) is

$$I_{bond} = \frac{\alpha(x) - \alpha_{fp}}{\alpha_{100\%cem} - \alpha_{fp}}$$  \hfill (15-10)

Their results are graphically presented in Fig. 15-23.

If the acoustic wave energy is assumed to travel in straight lines parallel to the axis of the pipe, the Pardue equation (Eq. 15-10) represents the unbonded and bonded sections as sequential or serial paths for the acoustic wave, while the Gai and Lockyear equation (Eq. 15-11) represents them as parallel paths (Fig. 15-24). The former represents measured attenuation as a weighted sum of bonded and unbonded attenuations; the latter represents measured amplitude as a sum of bonded and unbonded amplitudes.

Figure 15-25 shows results of recent unpublished modeling work that takes wave-propagation effects into account. The model computes the amplitude at the 3-ft receiver and the 2.4- to 3.4-ft attenuation rate for a given cement coverage. The results showed that the BPI relationship overestimates the true cement coverage, and the BI equation (from both the CBL amplitude and attenuation) slightly underestimates the cement coverage. The same study found that the tiny precursor before the conventionally used $E_{1}$ arrival follows the BPI relationship more closely than the BI relationship.

The discrepancies in the results of different experimental and theoretical BI values are probably due in part to the different test conditions—different transducer frequencies, transducer pulse shapes, transducer polarities, receiver spacings, casing diameters, and casing thicknesses. No systematic experimental BI studies have been reported over a range of casing sizes using...
a commercial tool in well-controlled conditions. In view of the uncertainties surrounding the BI calculation, it should be treated as a semiquantitative interpretation tool valid for fluid channels in well-bonded cement.

In 1963, Pardue et al. studied how the attenuation rate varies as a function of cement composition, casing size and thickness. They constructed a famous nomogram known as the “CBL Interpretation Chart.” This nomogram, which shows the correlation between the CBL signal and the cement compressive strength, was later modified for lightweight cements (Bruckdorfer et al., 1983). In 1987, Jutten and Parcevaux showed that, over a large variety of cement-slurry formulations, the CBL attenuation rate is related to the acoustic impedance of the set cement, not the compressive strength. Provided the cement is set, these experimental results, also valid for foamed cements, could be used to modify the CBL interpretation chart that now shows a relationship between cement acoustic impedance \( Z \) and the CBL signal (Fig. 15-26).

Unfortunately, a CBL-VDL interpretation does not give direct access to hydraulic isolation information. From local experience, empirical charts have been developed that give the minimum length required for zonal isolation as a function of the BI and the casing size. These charts, established without any theoretical or experimental background, should be used with extreme caution.

The CBL-VDL interpretation is thus restricted to an evaluation of the cement placement, in relationship to the quality of the cement. Well parameters, cement-job events, and pre- and postjob well histories are required to make the best possible evaluation from a CBL. Well parameters and cement-job events are necessary to compute the expected log response, while the cement job recording and pre- and postjob events are required most of the time to understand if the discrepancies between the expected response and the actual log, if any, are caused by the cement, incomplete mud displacement, or a microannulus. Figure 15-27 shows a flowchart for CBL interpretation that covers the points discussed above.
15-4.4.2.8 Bond-log presentation formats

Bond logs are presented on a standard three-track log format with the depth track between Data Tracks 1 and 2 (Fig. 15-28). Track 3 contains the full-wave display, either as the waveforms or a variable-intensity display. The common scale is 200 to 1,200 μs, although other scales are available for special cases such as extra-large holes or extra-slow formation sound speeds.

Track 1 traditionally contains the transit-time measurement (or possibly a derivative thereof for the borehole-compensated tools), as well as a correlation curve (gamma ray or neutron). Casing collars are usually indicated here but may also appear in the depth track or Track 2. A common scale for the conventional 3-ft transit time is 200 to 400 μs. This has the advantage of a single scale for almost all casing sizes. However, the small changes in time that correspond to major eccentricity (4 to 5 μs are recommended limits) require a more sensitive scale (100-μs width).

Track 2 contains the amplitude curve, attenuation-rate curve, or both. The attenuation-rate curve is usually presented on a scale of 0-to-20 dB/ft. Amplitude-curve scales are not standardized, although a 0-to-100 or 0-to-50 mV scale is very common, with an amplified curve presented on a 0-to-20 or 0-to-10 mV scale. The double scale is very important because free-pipe readings can approach 100 mV or more, while fine resolution of perhaps 1 mV or less may be required at low amplitudes.

Fig. 15-27. CBL interpretation—general flowchart.
Fig. 15-28. Standard three-track bond-log format.
15-4.4.2.9 Quality control of CBL/VDL logs

Quality control can easily be divided into a step-by-step procedure (Fig. 15-29). If the first two steps apply for every log, the CBL has a special curve for quality control—the transit-time curve (Fitzgerald et al., 1983; Bigelow, 1985). If no transit-time curve is present on the log, no quality control of the log is possible, and the evaluation will be very limited. The next part of this chapter will assume that a transit-time curve is present on the log.

By comparing the measured transit time with the expected transit time (the time required for the sound wave to travel from the transmitter to the receiver through the mud and along the casing), the following conclusions can be drawn.

**Shorter transit time** is an indication of either poor sonde centralization or a fast formation. On the subject of eccentering, there have been recommendations that a 4-μs transit-time decrease or less is acceptable. This corresponds to an eccentering of about ¼ in. [0.32 cm] in fresh water. Because this amount of eccentering reduces the amplitude by more than 25% (Fig. 15-30), this recommendation is reasonable. There are several ramifications of the 4-μs limit.

- The measurement resolution of the logging instrument must be 1 μs or better.
- The log display must allow for ease of readability down to a 1- or 2-μs visual resolution, leading to the recommendation of using a 100-μs scale for the transit time across the track (Fertl et al., 1974; Fitzgerald et al., 1983). In the case of sonde eccentering, it is impossible to quantify the results of the cement job with the CBL. The influence of a fast formation, often also seen as a decrease in transit time, is discussed in Section 15-4.4.2.13.

**Slightly longer transit time (stretching)** is generally an indication of a good bond and should correspond to reasonably low amplitudes (Fig. 15-31). The BI concept is applicable. If the CBL amplitude is still high, check for interference caused by small cement-sheath thickness and high acoustic-impedance contrast at the cement/formation interface.

---

**Fig. 15-29. Quality-control flowchart.**
Longer transit times \((\Delta t > 15 \mu s)\) are called skips (Fig. 15-32). In this case, \(E_1\) is normally too small to be detected; thus, a good bond exists between the cement and casing. A cycle skip refers to a cycle of the original wave \((50 \mu s\) for a 20-kHz signal). In this case, in fixed-gate mode, the CBL amplitude must be below the detection level, and the BI concept applies. However, it is fairly common to have stable skips of more than 20 \(\mu s\) but less than 50 \(\mu s\). This is caused by energy reflections at the cement/formation interface, enhanced by large acoustic impedance contrasts as in concentric strings (Jutten and Corrigall, 1988). If applied in this situation, the BI concept will lead to erroneous conclusions, because the amplitude measured was not \(E_1\).
Influence of well parameters on the CBL

Temperature and pressure—The deeper a well, the higher the temperature and pressure will be. In addition to the pipe, cement, and formation, the velocity and attenuation of sound through wellbore fluids will be affected by downhole conditions (Fig. 15-33). The response of the transducers also will vary. In 1984, Nayfeh et al. published pressure and temperature corrections for the transducers used in CBL tools.

Wellbore-fluid properties—Wellbore-fluid properties have an effect on both the transit time and the CBL amplitude. Nayfeh et al. (1984) performed experimental and numerical work to study the effects of wellbore fluids on CBL-amplitude measurements. There are considerable differences in free-pipe amplitude between various brines (Fig. 15-34).

Casing size and thickness—As the casing size increases, so does the path through the wellbore fluid. This leads to some signal attenuation and decreased free-pipe amplitudes. However, for pipes cemented with the same cement system, the CBL amplitude typically increases with casing size. This can easily be explained by the increase of steel thickness, providing a smaller attenuation rate.

Cement thickness—When the cement thickness is too small, energy reflections at the cement/formation interface can interfere with the casing signal. These interferences are seen mainly in concentric strings, cylindrical holes with a small annular clearance, and well-centralized pipe (Jutten and Parcevaux, 1987). To determine if reflections interfere with \( E_1 \), it is necessary to accurately measure the openhole size and the acoustic properties of the cement when the log is run. Typical cement thicknesses that do not interfere with \( E_1 \) (20 kHz signal) can vary from 1 in. [2.54 cm] to 3 in. [7.6 cm], depending on the compressional-wave velocity through the cement. If the measuring gate is much larger than half of the period of the original signal, interference may induce erroneous amplitude measurements for even larger cement thicknesses.

In the special case of concentric strings (e.g., top of the liner), the resonance of the external casing induces strong signal perturbations, leading to an apparent frequency increase of the first few arches of the waveform. Experiments confirmed with field logs (Jutten and Corrigall, 1988) proved that high CBL amplitudes obtained in concentric casings are often artifacts caused by an excellent cement job between both casings and a measuring gate with an excessive amplitude. Some tools allow solving this problem by shortening the measuring-gate width. In the log shown in Fig. 15-35, the change from concentric casing to open hole is clearly shown by the frequency change in the VDL. In addition, the amplitude curve in the double-string section seems to indicate almost no cement, while an ultrasonic log would actually show cement and no difference between the double-casing zone and the single-casing zone.

Fig. 15-33. Effect of temperature on velocity of sound through water (3,200 psi).

Fig. 15-34. CBL free-pipe amplitude for different brines as a function of casing OD.
**Fig. 15-35. CBL/VDL in concentric casing.**

<table>
<thead>
<tr>
<th>Variable Density (µs)</th>
<th>Min. Amplitude</th>
<th>Max. Amplitude</th>
</tr>
</thead>
<tbody>
<tr>
<td>200</td>
<td></td>
<td>1,200</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>CBL Amplitude (mV)</th>
<th>0</th>
<th>50</th>
<th>10</th>
</tr>
</thead>
<tbody>
<tr>
<td>Va</td>
<td>0</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Signal frequency increased: larger number of thinner stripes

- Double string
- Cased and cemented open hole
- Cased and cemented open hole
**Fast formations**—The well-known “fast-formation effect” is a transit-time decrease. When the formations have higher velocities than the casing (slowness less than 57 μs/ft), the refracted formation compressional waves may arrive before the casing wave. In this case, the transit time is shorter than expected, and the amplitude characterizes the formation instead of the casing/cement bond. Therefore, the BI concept cannot be applied in this case. Qualitative evaluation is possible. If there is sufficient sound energy propagating through the formation to interfere with the early part of the waveform, it indicates the presence of some solid material between the casing and the formation.

In some cases, the transit time does not reflect the fast formation while the VDL clearly shows a formation arrival before the casing arrival. At the 5-ft [1.5-m] receiver, the formation signal has clearly overtaken the casing signal. There could be a “fast-formation” phenomenon at the 5-ft receiver, but not at the 3-ft [0.9-m] receiver. It depends on the annular thickness, the speed of sound in the cement, and the difference in the speed of sound between the rock and the casing. It is important to be aware of this subtlety, because the formation signal can be present in the fixed gate and thereby increase the amplitude considerably while the transit time is reading a larger value than in free pipe. An erroneous interpretation will result.

For example, given a bias-level threshold of 5 mV and an amplitude of 1 mV in a “slow formation,” both quite realistic values, the earliest formation arrival in an adjacent fast formation could drive the amplitude reading on the log up to as much as 5 mV without causing a transit-time decrease. However, standard interpretation techniques (BI) would indicate a channel covering 35% of the circumference of the pipe. One must not make the common mistake of assuming that, because the transit time has not decreased, the amplitude is uncontaminated by a fast formation.

On some borehole-compensated bond-logging tools, an additional spacing of 0.8 ft [0.2 m] exists to minimize the effects of fast formations in casing sizes smaller than 7 in. [18 cm]. When the formation has no influence on the measured peaks, the attenuation rate should be constant at all spacings. In the presence of a fast formation, the measured attenuation rate decreases with increasing spacing, because the increasing part of the sound energy arrives in the early portion of the waveform. In this case, the 0.8-ft [0.2-m] spacing attenuation rate is larger than other attenuation rates (or the amplitude is lower).

15-4.4.2.11 Influence of cement job parameters on the CBL

The most common cause of cement-job failure is poor mud removal, and poor mud removal will lead to a complicated CBL. Some causes of poor mud removal are obvious: casing not centralized, cement-slurry density lower than that of the drilling mud, and low-viscosity cement slurry pumped behind a viscous drilling fluid. Others are more complex and require the use of advanced cement-placement simulators such as those described in Chapter 5. Slurry-placement evaluation should be performed before a cement log analysis. This requires actual job data (flow rate, pressure, and density) during the entire job and other information, such as openhole size and casing centralization.

Because slurries of different densities normally have different acoustic properties, it should be easy to detect the transition between the lead and tail slurries on the log. This concept is of prime importance for cement coverage estimation, because 100% bonding across the lead section corresponds to a much lower CBL attenuation rate than 100% bonding across the tail section. This is mainly caused by the difference in acoustic impedance, directly linked to density. A BI log should be computed section by section, without forgetting that the minimum cement thickness required to apply these rules also depends on the acoustic properties of the cement.

Sometimes it is possible to estimate mud removal by comparing the expected top of the cement with the one computed from the hole geometry and volumes pumped. However, such an estimation must be done quite carefully, because many parameters are involved, including the accuracy of the caliper and flowmeters as well as volume changes caused by fluid loss and lost circulation.

Cement slurries prepared at lower-than-designed densities often exhibit more free water and sedimentation, longer thickening times, and lower acoustic impedance. This can also be seen on the log.

15-4.4.2.12 Influence of post-job events on the CBL

Several post-job events can influence the CBL results. Any pressure and temperature change applied inside the casing will induce casing deformations that modify the stresses in the cement and at the cement-to-formation and cement-to-casing interfaces. Such deformations can break these bonds, leading to the creation of a microannulus.
Work by Leslie et al. (1987) showed that the amplitude reduction of the sonic signal depends not only on the attenuation along the casing, but also on the efficiency of the acoustic coupling between the transducers and the casing wave. In the presence of a microannulus, the shear coupling is lost and the attenuation along the casing is negligible; however, the coupling is not lost when a fluid is in the microannulus. Using multiple-receiver tools, it is possible in theory to separate the coupling and attenuation rate, detect a microannulus, and even quantify the cement coverage behind the pipe.

In the absence of experimental work, knowledge of microannuli is based on field experience and common sense. Pilkington (1988) described the origin of microannuli in great detail, with the effects produced on hydraulic isolation. One should first try to analyze the origin of the potential microannulus. However, for cement job evaluation purposes, a CBL performed under pressure may be contraindicated because of the potential detrimental effects on hydraulic isolation. Several cases should be taken into consideration.

Thermal expansion or contraction
As cement sets, heat is generated, which increases the temperature in the wellbore. As explained at the beginning of this chapter, this heat is sometimes measured to detect the top of the cement. It will also cause expansion of the casing inside the wellbore. An approximate value is given by the following formula.

\[
\Delta d = \left( 6.9 \times 10^6 \right) \times C_{\text{csg}} \times \Delta T
\]

where

- \( C_{\text{csg}} \) = casing circumference (in.)
- \( \Delta d \) = diameter change (in.)
- \( \Delta T \) = temperature change (°F).

During the life of the well, the production of hot fluids or the injection of cold or hot fluids can also produce expansion or contraction of the tubular goods. The above formula can be used to estimate the magnitude of the induced geometrical change.

Mechanical expansion or contraction
Mechanical effects may result from internal casing pressure applied during pressure tests, remedial cementing, or stimulation jobs. Sometimes the casing is maintained under pressure while the cement sets, because of a float-equipment leak. After the cementing of a production string, it is also fairly common to replace the drilling mud by a lower-density completion fluid. The hydrostatic pressure reduction can produce a significant casing contraction and induce a microannulus if the bond between the casing and cement is not sufficiently strong. Carter and Evans (1964) detailed the diameter expansion of unsupported pipe when pressurized. Often, 1,000-psi differential pressure is sufficient to create a fairly large microannulus, especially for large casing sizes.

Mechanical fatigue
In deviated wells and on intermediate strings, drilling can produce a great amount of vibration and mechanical stress, concentrated in special places (e.g., kickoff points). These can damage the quality of the bond between the casing and cement.

For all of the cases mentioned above, if the cement is strong enough to withstand the deformation, the bond will not be affected. If the cement is still plastic when the stress is applied, the annular geometry will change. If the cement is not set when the stress is released, the bond should not be affected; however, if the cement hardens while the casing is significantly expanded, it may not follow the casing back when the stress is released, leading to the formation of a microannulus.

15.4.2.13 CBL/VDL examples
Well cemented section—A 7-in. [18-cm] casing (23 lbm/ft) was cemented at a shallow depth. The average hole size was between 12 and 17 in. [30 and 43 cm] for a bit size of 9 7/8 in. [23.7 cm]. The casing was cemented using two different slurries—a lead mixed at 10.6 lbm/gal [1,270 kg/m³] and extended with hollow silica microspheres and a tail mixed at 15.8 lbm/gal [1,890 kg/m³]. Both formulations contained 35% silica flour BWOC. The maximum displacement rate during this job was 2 bbl/min, achieving good mud removal.

The CBL was run several weeks after the job. The selected section shows the transition between the tail and the lead slurry (Fig. 15-36). The CBL amplitude is around 1 mV between 370 and 420 ft [113 and 128 m] across the tail and between 8 and 14 mV across the lead. At that time, the estimated compressive strengths were in excess of 5,000 psi for the tail and about 1,000 psi for the lead cement. As determined by using the CBL interpretation chart, the CBL amplitudes were expected to be less than 1 mV for the tail and around 4.0 mV for the lead, which would give a pessimistic BI of 65% on the section showing a 12-mV CBL amplitude. When using a modified CBL chart, with measured acoustic impedances of 6.0 MRayl for the tail and 3.2 MRayl for the lead, attenuation rates were computed and extrapolated to be about 1 mV for the tail and 8 mV for the lead. The CBL interpretation is similar for the tail cement across the bottom section. However, the discrepancy becomes critical for the lead, because the relationship between the CBL attenuation rate and cement acoustic impedance enables one to compute a more realistic BI of 85%.
**Fast formation**—The log example in Fig. 15-37 shows both a short interval of free pipe from uphole and another portion of the well. The VDL display contains much information. The free-pipe VDL character is distinct: very straight parallel bands and chevron-shaped diffraction patterns at the collars. In contrast, the rest shows wavy bands. The pattern of the bands corresponds to changes in the rock, as indicated by comparing the VDL data in Track 3 to the gamma ray curve in Track 1. These are formation signals that interfere with the attenuated casing arrival, preventing the performance of a quantitative evaluation. Nevertheless, the presence of these formation signals indicates that some solid material fills the annulus.

The amplitude curve is presented in Track 2. In the short free-pipe interval at the top, the amplitude is high and steady at about 60 mV, with a “kick” to the left at the collar. Below, the amplitude varies widely—from 2 mV to 30 mV. The high amplitudes are caused by a fast formation, not by a lack of cement. This is confirmed by the VDL display: the first red band in the fast-formation interval is farther left than the first red band in the free-pipe interval. The first formation arrival occurs earlier than the first pipe arrival in the fast formation. The transit-time curves track the fast formation very well. The sliding-gate transit time decreases in front of the fast formation.

The important point is that the amplitude measurement in a fast formation is meaningless. The amplitude is some part of the formation signal, not the first positive peak, $E_1$, of the free-pipe signal.

**Change in casing weight**—In the log shown in Fig. 15-38, there is an abrupt change in casing weight at 6,953 ft. The 5½-in. [14-cm] casing is 17 lbm/ft above the change and 23 lbm/ft below. Note the difference in CBL amplitude between the two weights—2 mV in the lighter casing and 5 mV in the heavier one. If a BI is run in this well, the reference point for 100% cemented must be changed for each pipe weight.

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*Fig. 15-36. CBL/VDL section across slurry change (10.6-lbm/gal slurry above 370 ft; 15.8-lbm/gal slurry below 370 ft).*
Fig. 15-37. CBL/VDL example showing the effect of a fast formation.
Microannulus—The two log sections shown in Fig. 15-39 demonstrate the effect of a microannulus on a CBL. The first section was logged without additional pressure at the surface.

- The pipe signals are visible in the VDL display as straight parallel bands at the earliest time.
- The formation signals appear later in the VDL as wavy bands.
- The amplitude is erratic at moderate values.

The second log is a pass over the same interval with 1,500 psi applied at the surface (Fig. 15-40). The color contrast on the VDL display for early pipe arrivals has either disappeared or is significantly reduced, and the amplitudes have decreased to much lower values. In this size and weight of casing, the expansion caused by the 1,500-psi increase is about 0.0008 in. [20 μm] of radius.
Limitations

Unfortunately, with traditional cement-bond logs, high amplitude over a cemented section may be caused by either channeling or to a microannulus. In both cases, the VDL will show strong casing signals (parallel stripes) and weak formation arrivals. The only way to differentiate both cases is to run a CBL under internal casing pressure. If there is a microannulus, there will be a significant amplitude reduction. If the CBL does not improve when pressure is applied, it can be either a large microannulus or a channel. Zonal isolation has probably not been achieved.

The alternative is to use ultrasonic tools to evaluate the cement job. These tools, described in the next section, can differentiate between channeling and a microannulus without applying internal casing pressure.

15-4.4.2.14 Pad-type sonic tools for cement evaluation

This category of sonic cement evaluation tools features multiple transmitters and receivers mounted on pads that are in contact with the casing wall. An example of this tool is described by Lester (1989). Lester’s device has six pads, each containing one receiver and one transmitter (Fig. 15-41).

The attenuation measurement is very similar to the CBL attenuation rate measurement described in Section 15-4.4.2.6 (Fig. 15-42). As mentioned earlier, compensated attenuation measurements do not require calibration and are independent of temperature and pressure.

![CBL/VDL example showing effect of pressurized casing.](image)

![Unfolded view of the six-pad configuration.](image)

\[
\text{Attenuation} = 10 \log \left( \frac{A_{12} \times A_{43}}{A_{13} \times A_{42}} \right)
\]

![Attenuation-compensated measurement in pad-type tool.](image)
Multiple-pad transducers are beneficial in that they provide azimuthal information (60° coverage in this case) and have very low sensitivity to logging-fluid effects. While tool eccentricity can have a large effect on conventional CBLs, the pad tool is much less sensitive. The distance between the transmitter and receiver is about 6 in., and the operating frequency is 100 kHz. Because of the short distance between transmitters and receivers (6 in. versus 36 in. for CBL), this tool is less affected by fast formations. Although the wavelength is five times shorter than the conventional CBL, attenuations measured by both techniques are very close.

The log presentation format presents the six measured attenuations with a tool orientation trace overlay (Fig. 15-43). A cement map is also presented. The white indicates that no cement is present. Black indicates an 80% BI. The conventional CBL display is shown as well. The amplitude curve is generated in the following manner. Six measured attenuations values are averaged around the borehole and then averaged over 3 ft of depth. This average attenuation is equivalent to the attenuation that would have been measured by a perfectly centered standard CBL tool operating in an ideal fluid. From this attenuation, the amplitude that would have been measured is calculated. Both the amplitude and the attenuation are presented. A VDL is also displayed, thanks to a transducer-receiver spacing of 5 ft.

<table>
<thead>
<tr>
<th>Gamma Ray</th>
<th>Min. Delta-T</th>
<th>Max. Delta-T</th>
<th>Depth (ft)</th>
<th>Relative Bearing</th>
</tr>
</thead>
<tbody>
<tr>
<td>0 (gAPI)</td>
<td>100</td>
<td>40</td>
<td>0</td>
<td>360</td>
</tr>
<tr>
<td>140 (µs/ft)</td>
<td>40</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

---

**Fig. 15-43.** Log display from multiple-pad cement evaluation tool (image courtesy of Baker Atlas).
15-4.5 Ultrasonic pulse-echo cement evaluation

15-4.5.1 History

Ultrasonic pulse-echo technology was first applied to well logging in the 1960s, when Zemanek and Caldwell (1969) designed a tool called the Borehole Televiewer for imaging the borehole wall. Ultrasonic tools operate at much higher sonic frequencies than acoustic tools, usually between 200 and 700 kHz.

Havira (1979; 1982) investigated ultrasonic methods to evaluate cement behind pipe and developed a tool called the CET\textsuperscript{1} Cement Evaluation Tool. Froelich et al. (1981) and Dumont et al. (1984) described this tool and presented field test results. The CET device has 8 transducers arranged at 45° intervals around the circumference of the tool to map the acoustic impedance of the material around the pipe. Finlayson et al. (1984) described the results of later field tests, along with results from an interpretation model incorporating gas bubbles in the annulus. In 1984, Catala et al. proposed merging the interpretations of the CET and CBL tools, using a combined display so that the individual limitations of each log could be overcome.

Later, Sheives et al. (1986) introduced an ultrasonic cement evaluation tool, the PET\textsuperscript{2} Pulse Echo Tool. A comparison between the PET log and conventional and compensated bond logs, based on runs in a test well constructed by the United States Environmental Protection Agency, was presented by Albert et al. in 1987.

In the early 1990s, Hayman et al. (1991) introduced a second-generation ultrasonic tool called the USI\textsuperscript{3} UltraSonic Imager. It uses a single rotating transducer to provide full coverage of the pipe circumference with greater accuracy. Comparisons with other logging tools were made in a full-scale simulator (Hayman et al., 1991). Graham et al. (1997) developed a similar tool, the CAST-V\textsuperscript{4} Circumferential Acoustic Scanning Tool—Visualization. The early CET and PET tools are now becoming obsolete.

Basic interpretation of the acoustic-impedance maps or images is performed by setting impedance thresholds to discriminate between liquids, solids, and gases. Goodwin (1989) suggested using the character of the acoustic measurements, in addition to their absolute values, to help discriminate between solids and fluids in the annulus. He observed that the measured impedances of solids are usually more variable than those of liquids. Statistical processing of ultrasonic images has become increasingly common since the early 1990s.

Harness et al. (1992) and Graham et al. (1994) made statistical analyses of PET data to improve the evaluation of low-density and complex cements. Butsch (1995) proposed a statistical interpretation method for the USI tool that combined conventional and statistical processing to discriminate between cement with gas (gas-cut cement) and fluid channels. An API report, Technical Report on Cement Sheath Evaluation (TR 10TR1, published in 1996), provided many examples of tool responses to materials in the annulus and stressed the usefulness of material “signatures” and statistical methods. This report made many useful recommendations for running and interpreting acoustic logs. Goodwin (1989) made suggestions similar to those in the API report. The interpretation of Butsch’s statistical technique has since been extended from gas-cut cement to any type of irregularly bonded cement (Morris et al. 2002; Butsch et al. 2002). The latter two papers described the evaluation of low-density and other specialized cements using conventional and statistical techniques. Frisch et al. (1999; 2000) described combined conventional and statistical processing methods developed for the CAST-V tool and presented log examples for foamed and conventional cements.

15-4.5.2 Advantages and disadvantages of ultrasonic tools

Ultrasonic tools make a small portion of the casing resonate by transmitting a broadband pulse (200 to 700 kHz) normal to the casing wall. Two major advantages of this technique compared to sonic methods are:

- less sensitivity to a liquid-filled microannulus between the pipe and cement
- good spatial resolution—about 1 in.\textsuperscript{2} of cross-sectional area—combined with full coverage by the second-generation rotating tools.

However, disadvantages arise from the high frequency compared to sonic tools:

- pipe rugosity or roughness caused by corrosion or deposits can affect the cement measurement
- performance is limited in heavy solid-weighted muds, especially OBMs, because of acoustic-wave attenuation.

15-4.5.3 Tools

The first-generation tools (CET and PET) consist of eight ultrasonic transducers arranged in a helical spiral around the sonde, each facing outward (Fig. 15-44). They are evenly spaced around the circumference of the tool body—one transducer every 45°. A ninth transducer, facing a reflector in the tool body, measures the speed of sound in the borehole fluid.
The second-generation tools (USI and CAST-V devices) use a single rotating transducer to achieve full coverage of the pipe wall. Measurements are made at a large number of points around the circumference: 36 or 72 for the USI tool and 100 for the CAST-V device. Depending on the pipe diameter, several rotating sub-assemblies are available to optimize the distance between the transducer and the pipe. While running into the well, the USI tool (Fig. 15-45) measures the acoustic properties of the well fluid (velocity and impedance) by pointing the transducer towards a built-in reflector. The CAST-V tool has a secondary fixed transducer facing a flat reflector to measure the acoustic velocity of the well fluid while logging.

Because the second-generation tools have largely replaced the earlier tools, the rest of this section will show examples for the newer tools.

**15-4.5.4 Principle of ultrasonic cement evaluation**

The basic idea behind the ultrasonic technique is to make a small area of the casing resonate through its thickness. The transducer sends out a short pulse of ultrasound and listens for the echo containing the resonance. If there is fluid behind the casing, it will tend to resonate or “ring,” but if there is solid cement behind the casing, the resonance will be damped. The resonance is analyzed to determine the cement’s acoustic impedance.

**15-4.5.5 Measurements and processing**

As illustrated in Fig. 15-46, four measurements are made on the ultrasonic echoes.

- Echo amplitude—an indicator of casing condition
- Internal radius of the casing—calculated from the transit time of the main echo
Casing thickness—calculated from the resonant frequency

Acoustic impedance of the material behind the casing—calculated from the form of the resonance.

The physics can be explained by assuming that the ultrasonic wave is planar and traveling perpendicular to a flat plate representing the casing. Figure 15-46 shows the wave paths and the echo train obtained from an ideal, infinitely short transmitted impulse. At the boundary between the pipe and the borehole fluid, most of the incident energy is reflected, and the balance is transmitted into the pipe wall. The fractions of incident acoustic pressure that are transmitted and reflected are given by the following formulas.

\[
K_{ref} = \frac{Z_2 - Z_1}{Z_2 + Z_1},
\]

and

\[
K_{trans} = 1 + K_{ref} = \frac{2Z_2}{Z_2 - Z_1},
\]

where \(K_{ref}\) is the reflection coefficient at the boundary between two materials of acoustic impedance \(Z_1\) and \(Z_2\), and \(K_{trans}\) is the transmission coefficient at the same boundary. The pressure transmission coefficient can be
greater than 1, but energy is always conserved because the intensity, $i$, of a wave in a medium of impedance $Z$ is given by

$$i = \frac{p^2}{Z},$$

(15-15)

where $p$ is the acoustic pressure.

The first, large reflection at the pipe wall returns to the transducer and provides a measurement of the pipe radius. The small fraction of the energy that is transmitted into the pipe bounces back and forth inside the pipe wall, losing energy into the annulus and hole at every bounce. The pressure-reflection coefficient inside the pipe is negative. Thus, the echo train consists of a large reflection from the internal surface of the pipe followed by an exponentially decaying series of inverted pulses. The time separation of the train of negative pulses is equal to the go-and-return time, $\Delta t$, in the pipe.

$$\Delta t = \frac{2h_{csg}}{v_{steel}},$$

(15-16)

where $h_{csg}$ is the casing thickness and $v_{steel}$ is the acoustic velocity in steel (19,450 ft/s [5,930 m/s]).

The resonant frequency of the pipe, $f_0$, is given by

$$f_0 = \frac{1}{\Delta t} = \frac{v_{steel}}{2h_{csg}}.$$

(15-17)

Figure 15-47 shows the signal transmitted by a USI transducer along with its frequency spectrum (i.e., the magnitude of the Fourier transform). The frequency spectrum shows that the pulse contains sound energy in the range of 200 to 650 kHz. This is the range corresponding to the inherent thickness mode resonant frequencies of oilfield casings from 0.18 to 0.6 in. [4.57 to 15.24 mm].

Figure 15-48 shows typical echoes from a casing backed by water and cement. The resonance has been magnified to show more detail. This diagram illustrates two points.

- Cement behind the pipe damps the resonance.
- The resonant frequency (shown by the spacing between the peaks in the resonance) is the same with water or cement behind the pipe.

While the basic principle of all ultrasonic tools is the same, there are differences in the way the signal processing is done, particularly for the cement impedance. The USI processing is shown in Fig. 15-49. The time from transducer firing to the main echo is used to calculate a radius. The distance that the tool is eccentered in the pipe is calculated from the radius measurements, and then the measurements are corrected foreccentering.
The magnitude of the main echo is measured. It is a qualitative indicator of pipe rugosity and useful for quality control. In tools other than the USI device, the amplitude forms part of the cement processing, in which it is used as a first-order correction for mud attenuation, tool eccentricity, and pipe rugosity.

The resonance signal is analyzed to calculate the thickness of the pipe and the impedance of the material behind the pipe. The thickness is determined from the resonance frequency (Eq. 15-17). The cement-impedance processing is different in each tool. The first-generation tools (CET and PET) measured the resonance energy in predetermined time windows. The USI processing is performed in the frequency domain, as outlined below.

The early part of the signal, covering the main echo plus roughly the first seven cycles of resonance, is selected by the dotted yellow window function shown in Fig. 15-49. The group delay spectrum of this signal is calculated as follows:

$$\tau = -\frac{d\phi}{d\omega}, \quad (15-18)$$

where $\phi(\omega)$ is the phase spectrum and $\omega = 2\pi f$ is the angular frequency. The group delay spectrum shows the pipe resonance as a dip. The frequency of the resonance $f_0$ gives the pipe thickness (Eq. 15-17). The width of the resonance $\Delta f/f_0$ depends on the cement impedance.

The thickness and impedance are determined by matching the planar model (Fig. 15-46) to the measured resonance using an iterative technique. The pipe properties are known, and, using a built-in casing sample, the logging fluid velocity and impedance are determined while running into the well. Therefore, the only unknowns are the pipe thickness and cement impedance. The final step of the processing is to apply tabulated corrections for casing diameter, transducer size, and fluid velocity, which are calculated using a three-dimensional model (Randall and Stanke, 1988).

### 15-4.5.6 Response to materials in the annulus

**Gas**

Gas has an acoustic impedance below 0.1 MRayl. It acts as a barrier that totally reflects the ultrasound.

**Liquid**

Liquids have impedances in the range 1 to 3 MRayl (Tables 15-5 and 15-6).

**Table 15-6. Sound-Velocity Values for Cement Systems with Different Densities**

<table>
<thead>
<tr>
<th></th>
<th>Neat Class G</th>
<th>Cement 1</th>
<th>Cement 2</th>
<th>Cement 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density (kg/m³)</td>
<td>1,890</td>
<td>1,115</td>
<td>1,115</td>
<td>1,000</td>
</tr>
<tr>
<td>Compressional velocity (m/s)</td>
<td>3,600</td>
<td>3,000</td>
<td>2,700</td>
<td>2,400</td>
</tr>
<tr>
<td>Shear velocity (m/s)</td>
<td>2,000</td>
<td>1,550</td>
<td>1,429</td>
<td>1,250</td>
</tr>
</tbody>
</table>

**High-quality cement**

Neat cement has an impedance of about 6 MRayl. Light cements can have impedances as low as 2.5 MRayl, overlapping the liquid range (Table 15-3). As with acoustic logging, foamed cements have particularly low impedance and pose special interpretation problems.

If the shear bond between the cement and casing is good, the USI tool impedance reading will be higher than the compression-wave impedance. This occurs because the shear coupling introduces additional resonance damping, as illustrated in Fig. 15-50.
Cement with channels

Figure 15-51 shows a USI laboratory measurement in which a casing was initially immersed in water and then surrounded by neat cement with artificial gas channels. The casing was logged as the cement set. The gas (0 MRayl), water (1.5 MRayl), and slurry (3 MRayl) readings were close to the expected values. The solid cement reading was higher than its compression-wave impedance (measured simultaneously on a separate sample) because of the shear coupling effect. The narrowest 20-mm channel was indicated clearly, though the reading was 1 MRayl higher, and the 40-mm channel was measured correctly.

Microannulus

For the purposes of discussing ultrasonic logs, a microannulus will be defined as a small fluid-filled gap, less than a few hundred micrometers thick, between the casing and cement. Such gaps are most often created by pressure and temperature changes, or by a mud or oil film left on the casing. Thicker fluid layers will be referred to as a “mud layer” or as a channel.

The effect of a microannulus on the ultrasonic pulse-echo signal depends on whether it is filled with gas or liquid. For a water-filled microannulus, the measurement is weakly affected. Hayman et al. (1991) reported experiments and theory for a microannulus between a 6-mm thick casing and a neat Class G cement (Fig. 15-52). The experiment was performed by pulling a slightly conical casing vertically out of the cement. Initially, the impedance reading is 20% high because of shear coupling. Once the bond between the casing and cement is broken, the microannulus fills with liquid, and the correct impedance is measured. Further increases in the size of the microannulus decrease the measured value. For a 0.1-mm thick microannulus, it is still possi-

Fig. 15-50. Shear coupling effect. Impedance reading is higher for well-bonded solids than liquids.

Fig. 15-51. USI laboratory measurements within a casing with artificial gas channels.

Fig. 15-52. Effect of a liquid-filled microannulus on the USI signal for a 7-in. diameter, 6-mm thick casing (experiment and theory) and a 12-mm thick casing (theory only).
Table 15-6 displays results for the modeling of liquid-filled microannuli behind 8- and 12-mm thick casings for four types of cement (Table 15-6). The results are shown in Figs. 15-53 and 15-54.

The conclusions from both liquid-filled microannulus studies are as follows.
1. The USI measurement is insensitive to small amounts of liquid-filled microannulus.
2. The measured impedance of neat cement is more sensitive to a microannulus than lower-density cements. The impedance of neat cement is reduced by 50% (staying above 3 MRayl) when the size of the microannulus is greater than 0.15 mm, depending on casing thickness.
3. When lower-density cements are present, the drop in measured impedance is less than 0.2 MRayl when the size of the microannulus is greater than 0.2 mm, depending on casing thickness.
4. When the cement is perfectly bonded to the casing, shear coupling boosts the impedance.

**Fig. 15-53.** Modeled effect of a liquid-filled microannulus on the USI signal for a 7-in. diameter, 8-mm thick casing and four types of cement.

**Fig. 15-54.** Modeled effect of a liquid-filled microannulus on the USI signal for a 7-in. diameter, 12-mm thick casing and four types of cement.
A log example of a liquid-filled microannulus is shown in Section 15-4.6.1.

A gas-filled microannulus affects the ultrasonic measurement much more strongly than a liquid-filled microannulus, because the wavelength in gas is shorter and the gas impedance is much lower. Figure 15-55 shows microannulus effects for air and water, measured by Jutten and Hayman (1993). The ultrasonic measurement fails to indicate cement as soon as a tiny gap of less than 1 μm is created.

Gas microannulus examples are shown later in Section 15-4.6.1.

Mud layer

A mud layer, defined as a liquid-filled gap between the casing and cement more than a few hundred micrometers thick, gives low impedance readings in the liquid range. Such layers can be created by cement fingering through the mud, leaving mud on both the casing and the formation. A figure in Section 15-4.6.1 shows a log with a suspected mud layer.

Thin cement

The processing of ultrasonic measurements is performed with a model in which only mud, pipe, and annulus material are present. However, the annulus material has a finite thickness, and the reflection of energy occurs at the annulus/formation or annulus/outer-casing boundary. This reflection can affect the measured echo, especially if certain conditions exist:

- thin cement sheath
- smooth surface on the wall of the hole
- large acoustic impedance contrast between the cement and formation.

A well-cemented liner inside an outer casing is particularly likely to be affected by reflections.

The formation reflections may be in or out of phase with the desired casing resonance, depending on the cement thickness and velocity, and the impedance measurement will be reduced or increased accordingly. Because the casing is usually eccentered in the annulus, the thickness of the annulus is not constant, and the formation reflections create a pattern of interference fringes centered on the narrow part of the annulus (Fig. 15-56). Successive fringes indicate a change of one-half wavelength in the annulus thickness, where the wavelength, \( \lambda \), is given by

\[
\lambda = \frac{v_{cem}}{f_0} = \frac{2 \times v_{cem} \times h_{csg}}{v_{steel}}.
\] (15-19)

For example, if there is neat cement behind a 9-mm thick casing, \( \lambda/2 = 5 \) mm. These patterns can be easily recognized on the cement images produced by the second-generation USI and CAST-V tools.

![Fig. 15-55. Experimental liquid and gas microannulus effects on the USI measurement, using a 4.7-in. diameter, 9-mm thick casing. Reprinted with permission of SPE.](image)

![Fig. 15-56. Interference caused by formation reflections when the pipe is eccentered in the hole, where \( n \) is an integer denoting the number of wavelengths, denoted by \( \lambda \). Destructive interference occurs when the annulus thickness is \( n\lambda/2 \), reducing the resonance amplitude and increasing the measured impedance. The thinner the annulus, the more severe the effect is. A figure in Section 15-4.6.1 shows an example of reflections from an outer casing.](image)
15-4.5.7 Other factors affecting tool response

Casing shape
Most oilfield casings are manufactured by forging. The external surface is usually extremely smooth and cylindrical, but the internal surface has characteristic wave patterns with peak-trough heights on the order of 10% of the thickness. These manufacturing patterns often affect the cement image but do not usually affect the interpretation. They should be examined during quality control operations. A figure in Section 15-4.6.1 shows a log affected by casing shape.

Tool eccentering
Excessive tool eccentering can affect the measurements, especially in places in which the ultrasonic beam is no longer perpendicular to the casing wall. The recommended eccentering limit for the USI tool is

$$L_{\text{ecc}} < 0.1dh$$  \hspace{1cm} (15-20)

where

- $d$ = diameter (in.) and $h$ = thickness (in.).

Excessive eccentering will produce vertical stripes on the cement log.

Rugose casings
Rugosity caused by corrosion or deposits can degrade results significantly. The amplitude image is the best indicator of this problem. A log affected by rugosity is shown in a series of log examples presented in Section 15-4.6.1.

Heavy muds
Heavy muds, especially OBMs, attenuate ultrasound strongly and degrade the signal-to-noise ratio. The USI log is relatively immune to mud attenuation compared to the CET log, and it will work up to about 16 lbm/gal [1,920 kg/m$^3$] in WBM and 13 lbm/gal [1,560 kg/m$^3$] in OBM. The exact limits depend on mud composition, pressure, and temperature and are difficult to predict.

Pipe coatings
A complication closely related to the microannulus is thin coatings on the outside of the pipe (e.g., mill varnish and epoxy/sand coatings). An epoxy thickness of up to 0.4 mm (0.02 in.) can be tolerated with little effect on the log.

Casing thickness
The CET log is affected by casing-weight changes and needs calibration for each weight. The USI log processing avoids this difficulty.

15-4.5.8 Basic interpretation

At the time the first logging tools were developed, the industry traditionally described cement in terms of compressive strength. Laboratory testing was performed on different formulations to determine empirical correlations between the acoustic impedance and compressive strength. Empirical correlations have extremely limited validity, and only the measured acoustic-impedance value should be used for interpretation.

15-4.5.8.1 Impedance thresholds
The cement impedance can be presented as a raw impedance map. Basic interpretation of the impedance maps or images is performed by setting thresholds to discriminate between gas, liquids, and solids. Currently recommended impedance thresholds for the USI maps are shown in Table 15-7 and illustrated in Fig. 15-57.

<table>
<thead>
<tr>
<th>Threshold</th>
<th>Value (MRayl)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas (or dry microannulus)/liquid</td>
<td>0.3</td>
</tr>
<tr>
<td>Solid/liquid</td>
<td>Impedance of mud in annulus + 0.5 (default 2.6)</td>
</tr>
<tr>
<td>Maximum impedance</td>
<td>4 to 8 depending on expected cement impedance</td>
</tr>
</tbody>
</table>

**Fig. 15-57.** Impedance thresholds to distinguish between gas (or dry microannulus), liquid, and solid.
The liquid/solid threshold should be set 0.5 MRayl above the impedance of the mud in the annulus, whose value can either be taken from the fluid-properties measurement if the same mud is used for logging or can be estimated using software developed by the various logging companies. The upper limit of the display scale should be set according to the expected cement impedance, which can be measured using the ultrasonic cement analyzer (Appendix B) or estimated from the various proprietary software packages.

Published thresholds for the CAST-V tool (Frisch et al., 2000) are reproduced in Table 15-8. Additional thresholds are used to distinguish liquid containing gas and the solid/liquid transition.

### Table 15-8. Impedance Image Ranges for an Ultrasonic Imaging Tool

<table>
<thead>
<tr>
<th>Material</th>
<th>Color</th>
<th>Impedance Image Range (MRayl)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas</td>
<td>Red</td>
<td>0–0.38</td>
</tr>
<tr>
<td>Gas-cut liquid</td>
<td>Light blue</td>
<td>0.38–1.15</td>
</tr>
<tr>
<td>Liquid</td>
<td>Blue</td>
<td>1.15–2.30</td>
</tr>
<tr>
<td>Solid-liquid transition</td>
<td>Yellow</td>
<td>2.30–2.70</td>
</tr>
<tr>
<td>Low-impedance cement</td>
<td>Light brown</td>
<td>2.70–3.85</td>
</tr>
<tr>
<td>Medium-impedance cement</td>
<td>Dark brown</td>
<td>3.85–5.00</td>
</tr>
<tr>
<td>High-impedance cement</td>
<td>Black</td>
<td>&gt;5.00</td>
</tr>
</tbody>
</table>

#### 15-4.5.8.2 Statistical approaches

The simple-threshold interpretation may be ambiguous, because a number of conditions may cause solid materials to have a low impedance as measured ultrasonically. These conditions include genuine low-impedance cement (e.g., foam), poor bonding (especially dry microannulus), and mud contamination. Goodwin (1989) pioneered the use of acoustic-impedance variations to help distinguish solids from fluids in the annulus. The guiding principle is that a liquid or gas in the annulus has a constant, uniformly low impedance, while a “low-impedance” solid material usually has a more variable measured impedance.

Goodwin initially used the eight raw impedance curves provided by the first-generation tools. With the much larger number of measurements provided by the second-generation tools, it is more convenient to process the images than to look at curves. Both the USI and CAST-V logs have statistical image processing algorithms. The USI algorithm (Butsch, 1995) originally called the “gas-cut algorithm,” is now called the “microdebonding algorithm” because partial, uneven, and localized debonding is thought to be the most common cause of variability in measured cement impedance. Gas influx can cause debonding because of dehydration and fractures, but it is just one of several possible mechanisms for variable bond. Another processing method, described by Frisch (1999, 2000), is called advanced cement evaluation or statistical variation processing.

The USI microdebonding algorithm is illustrated in Fig. 15-58. It calculates the standard deviation of the cement impedance in four directions around each image pixel. If all four standard deviations are higher than set thresholds, and the cement impedance is low (in the gas or liquid classes), the current pixel is considered to be locally debonded and is colored green. Usually, two images are presented: the raw acoustic impedance and the interpreted image with microdebonding.

![Fig. 15-58. Illustration of the microdebonding processing for a USI measurement pattern with 36 radial samples and a 1.5-in. vertical sampling rate inside a 5.5-in. casing.](image-url)
there is either high impedance or high variance and showing fluid otherwise.

Statistical processing has certain limitations.

- The variance thresholds are empirical. Sometimes too much “liquid” (blue) is indicated when the bonding is obviously patchy. On the other hand, casing-shape effects, casing rugosity, or irregular tool movement sometimes provoke variations in measured impedance that are interpreted as debonding. Such artifacts must be detected by quality control. The variance thresholds should ideally be tuned in a similar type of casing surrounded by known material, such as free pipe.

- Solid cement can be associated with a low-variance, low-impedance image. For example, an extended dry microannulus has flat, near-zero impedance and remains red on the cement map. Homogeneous, well-bonded, light cement can also have a low variance.

Statistical processing log examples are shown in Section 15-4.6.1.

**15-4.5.9 Log presentation**

Log presentations vary from region to region and between service companies. Schemes used for labeling curves also differ. The data can be classed into six types. Figures 15-59 and 15-60 show presentation examples, and Fig. 15-61 shows an example of a full log with API headers.

**Borehole fluid data**

The measured speed of sound in the borehole fluid is required for the radius calculations. It may also be displayed on the log. It is presented as slowness, the inverse of velocity. This curve indicates density changes with high sensitivity. Occasionally, it proves useful in locating fluid changes in the well (e.g., oil on top of water and salt influx).

The USI tool measures not only the acoustic velocity, but also the acoustic impedance of the fluid, because the latter is needed for the cement impedance processing. Both measurements are made while running the tool into the well, and the measurements are shown in cross-plots labeled fluid properties measurement (FPM), as in Fig. 15-59.

**Quality control and auxiliary data**

Quality control data include the tool eccentric curve and processing flags. The recommended eccentric limit for the USI tool is 0.1d. The USI flags indicate problems with the acquisition and processing. They are displayed as a map.

![Fig. 15-59. USI fluid-properties-measurement (FPM) plots: fluid slowness (labeled velocity) and fluid impedance.](image)

Other information includes the inclinometer data, the conventional magnetic collar locator, and a gamma ray log for depth correlation. The inclinometer, which may be included in the tool or in a separate tool (in the case of the USI device), indicates the hole deviation and the rotation of the tool compared to vertical in deviated wells. The rotation curve is labeled “relative bearing,” and it allows the images to be oriented with the low side of the well in the center of the image. The high-low orientation is extremely useful in interpretation of primary cement jobs. The casing data described in the next section also form an essential part of quality control.
Fig. 15-60. USI log presentation with both casing and cement data.

Fig. 15-61. Standard USI presentation.
Casing data
The echo amplitude is presented as an image in which dark colors indicate low amplitude. Curves of minimum, mean, and maximum amplitude are also shown.

The measured casing radii are corrected for eccentricing and presented as an image. Commonly, the image shows the radius compared to the mean value at each depth, with blue indicating smaller radii and red larger radii. Thus, casing corrosion and wear show up as red areas. The casing thickness data are usually presented in a similar fashion, with red indicating thickness below average and blue thickness above average. The internal radius and thickness are summed to calculate the external radius. Internal- and external-radius curves are shown together, with shading to indicate the casing cross section. Minimum-, mean-, and maximum-thickness curves are also plotted separately.

Cement/annular data
The primary purpose of the cement imaging tools is to determine what is in the annulus. There are four common types of cement images.
1. The raw impedance image on a white-yellow-brown color scale. The white color corresponds to 0 MRayl, while the black upper limit is usually adjusted to a value in the range of 4 to 8 MRayl according to cement impedance.
2. The conventional interpreted cement image using impedance thresholds to distinguish gas (red), liquid (blue), and cement (yellow-brown). Typical thresholds have been listed in Tables 15-5 and 15-6.
3. The standard deviation or variance image, in which higher variability regions are darker.
4. The combined conventional/variance image, providing the most complete interpretation. This presentation is labeled “cement with microdebonding,” and microdebonded areas are colored green.

Usually, two or three of these images are shown on the right-hand side of the log, as in Fig. 15-60.

If the hole deviates from vertical orientation, the display can be adjusted to present the image from the low side of the hole in the middle of the track and the high side at the edges.

An ultrasonic BI track can be included, showing the percentage of cement, liquid, and gas at each depth. This allows a quick comparison with the CBL BI. In addition, curves of minimum, mean, and maximum acoustic impedance are typically shown.

CBL/VDL data
When the ultrasonic tool is run in combination with a sonic log, the CBL/VDL data are usually presented alongside for easy comparison.

Openhole and cementing data
For effective cement evaluation, well data and cementing data are just as important as the acoustic logs. Specialized presentations add openhole data, such as calipers and lithology, and cementing data, such as predicted casing standoff and predicted cement impedance. Special log headers allow inclusion of detailed cement reports.

15-4.6 Quality control
A step-by-step procedure should be followed to control the quality of the cement-evaluation log. The following is a general procedure.

- The repeat section and main log must be consistent.
- Acquisition and processing parameters must be included on the log. Check the solid/liquid impedance threshold and the maximum impedance of the color scale. These values should also be indicated on the color scale.
- Check that eccentricing is inside the recommended tolerance.
- Verify that the casing radius and thickness are close to nominal values in uncorroded areas.
- The casing must be in good condition, and radius and thickness must be accurate for a good cement log. The echo-amplitude image is a good indicator of casing condition. Corrosion and deposits show up as low-amplitude (dark) areas.
- If a free-pipe section is present, the mean acoustic impedance should equal the expected impedance of the fluid in the annulus, plus or minus the tool accuracy.

Figure 15-59 shows a typical fluid properties measurement with a fluid-velocity crossplot and a fluid impedance crossplot. The fluid velocity curve should be smooth and consistent with the fluid type (Table 15-9).
The measured fluid impedance should have low dispersion (below about 0.1 MRayl) and be within 10% of the theoretical value, calculated as follows.

Clear fluids:

\[ Z_{\text{mth}} = \rho \left( \frac{304.8}{(v_{\text{fluid}})^{-1}} \right) \]  \hspace{1cm} (15-21)

Weighted muds:

\[ Z_{\text{mth}} = B \rho \left( \frac{304.8}{(v_{\text{fluid}})^{-1}} \right), \]  \hspace{1cm} (15-22)

where

- \( B \) = correction factor in the range 0.85 to 1.0
- \((v_{\text{fluid}})^{-1}\) = fluid slowness (μs/ft)
- \( Z_{\text{mth}} \) = theoretical mud impedance (MRayl)
- \( \rho \) = fluid density (g/cm³).

An empirical formula for the \( B \) factor is available in proprietary logging company software. Figure 15-12 shows examples of \( B \) factor for typical WBM and OBM.

The value of fluid impedance, \( Z_{\text{mud}} \), used for processing the log must be verified. It should be on the parameter list at the bottom of the log. If the parameters have been zoned versus depth, then the zoned values of \((v_{\text{fluid}})^{-1}\) and \( Z_{\text{mud}} \) will be at the top of the log.

If the measured and theoretical fluid-impedance values differ, then the theoretical value should generally be used in brine or oil. The fluid-velocity measurement used to calculate the theoretical value is more accurate than the fluid-impedance measurement. In weighted mud, the theoretical value should be used; however, two points must be considered: (1) the \( B \) factor is accurate to only 5–10%, and (2) there may be sedimentation in the well. The log must be checked in a known free pipe or a gas zone, if possible, to verify that the \( Z_{\text{mud}} \) value is correct. An error of 0.1 MRayl in \( Z_{\text{mud}} \) changes the calculated cement impedance by about 0.5 MRayl.

### 15-4.6.1 Combined interpretation examples

The ultrasonic image shows the acoustic impedance and the distribution of materials around the casing; therefore, it is usually much easier to interpret than a CBL/VDL log. Most of the following examples are combined ultrasonic-sonic logs. A combined interpretation provides a coherent picture and compensates for limitations of the individual logs. As already discussed, the CBL-VDL has an ambiguous response to channeling, liquid-filled microannuli, and contamination. A pressure pass is needed to diagnose a microannulus. The ultrasonic log is very sensitive to gas and dry debonding. It is affected by poor casing conditions and attenuation in very heavy mud. Table 15-10 compares the responses of CBL-VDL and ultrasonic measurements.

### Table 15-9. Typical Borehole-Fluid Slowness

<table>
<thead>
<tr>
<th>Fluid</th>
<th>Slowness (μs/ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Brine</td>
<td>160–200</td>
</tr>
<tr>
<td>Water</td>
<td>200</td>
</tr>
<tr>
<td>WBM</td>
<td>180–210</td>
</tr>
<tr>
<td>Oil and OBM</td>
<td>210–250</td>
</tr>
</tbody>
</table>

598 Well Cementing
<table>
<thead>
<tr>
<th></th>
<th>USI Tool</th>
<th>CBL-VDL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Resolution</td>
<td>1.2 in.</td>
<td>360° × 3 ft</td>
</tr>
<tr>
<td>Gas</td>
<td>Gas (0 MRayl)</td>
<td>Higher amplitude than free pipe</td>
</tr>
<tr>
<td>Liquid</td>
<td>Liquid (1–3 MRayl)</td>
<td>Free pipe</td>
</tr>
<tr>
<td>Well-bonded cement</td>
<td>Cement (4–8 MRayl)</td>
<td>Good bond</td>
</tr>
<tr>
<td>Very light cement</td>
<td>Low contrast from liquid</td>
<td>Low contrast from liquid</td>
</tr>
<tr>
<td>Dry microannulus (debonded cement)</td>
<td>Dry microannulus or gas (0 MRayl)</td>
<td>Good-to-fair bond</td>
</tr>
<tr>
<td>Wet microannulus</td>
<td>Medium impedance cement</td>
<td>Poor bond (ambiguous) Pressure pass needed</td>
</tr>
<tr>
<td>Mud layer on sector</td>
<td>Liquid channel</td>
<td>Fair bond (ambiguous)</td>
</tr>
<tr>
<td>Contaminated cement</td>
<td>Low-impedance cement</td>
<td>Fair bond (ambiguous)</td>
</tr>
<tr>
<td>Mud channel</td>
<td>Channel</td>
<td>Fair bond (ambiguous)</td>
</tr>
<tr>
<td>Narrow gas channel</td>
<td>Gas channel</td>
<td>Cement</td>
</tr>
<tr>
<td>Cement/formation bond</td>
<td>Not seen</td>
<td>VDL qualitative indication</td>
</tr>
<tr>
<td>Reflections from outer casing or hard formation</td>
<td>Slightly affected (interference patterns)</td>
<td>Strongly affected (poor bond shown)</td>
</tr>
<tr>
<td>Casing condition</td>
<td>Very sensitive</td>
<td>Slightly sensitive</td>
</tr>
<tr>
<td>Mud-density limit</td>
<td>&lt; 16 lbm/gal (WBM)</td>
<td>No limit</td>
</tr>
<tr>
<td></td>
<td>&lt; 13 lbm/gal (OBM)</td>
<td></td>
</tr>
</tbody>
</table>
Good cement

Figure 15-62 is a combined USI and CBL-VDL log in high-quality, well-bonded neat cement. The ultrasonic image shows cement all around the casing with a mean impedance of 8 MRayl. The CBL amplitude is low and flat, and the VDL indicates a weak casing arrival and a strong formation arrival.

![Graphical representation of the USI and CBL-VDL log](image)

**Fig. 15-62.** A USI and CBL-VDL log of good cement. AI means acoustic impedance.
**Mud channel**

The USI image in Fig. 15-63 shows a wide, 180° mud channel (blue). The cement color (medium brown) indicates an impedance of about 5 MRayl, which is lower than expected for neat cement and suggests mud contamination. The image is a conventional interpreted map whose colors are allocated according to the measured impedance. The CBL-VDL log is coherent with the USI log, although on its own it would be ambiguous. The CBL amplitude is high and variable, and the VDL indicates a strong casing arrival and a weak formation arrival.

*Fig. 15-63. USI and CBL-VDL log of a mud channel.*
Cement top
At the top of the job shown in the previous example, the USI image indicates mud and traces of low-impedance (yellow) contaminated cement, as shown in Fig. 15-64. The CBL amplitude is high and flat, as it would be in free pipe. Despite the strong casing arrival on the VDL, there is a weak formation arrival consistent with traces of cement on the USI image. As is often the case, there is no well-defined cement top.

Low-density cement
Figure 15-65 shows the USI log of a mixed aggregate 11-lbm/gal cement job in 7-in. casing at 73° deviation. The wellbore fluid while drilling and cementing was an 8.8-lbm/gal OBM. The log was run 4 days after cementing. The gamma ray curve indicates the production interval where perforations were planned, a shale section that must provide the isolation, and the water sand at the bottom. The USI log showed full cement coverage in the shale interval with impedances in the range of 3 to 5 MRayl. Production tests showed no water production, confirming zonal isolation.

Fig. 15-64. USI and CBL-VDL log of cement top.
**Fig. 15-65.** USI log showing low-density cement.
Mud layer
The USI and VDL data in Fig. 15-66 indicate a wide channel. However, in this case the cement simulations using cement-placement software gave no reason to suspect a channel. Further simulations suggested that the most likely explanation was cement fingering through the mud, leaving a few millimeters of mud on the casing and formation.

Fig. 15-66. USI and VDL log showing probable mud layer.
Wet microannulus

In Fig. 15-67, the USI tool shows medium-impedance cement, but the CBL is high and flat and the VDL shows a strong casing arrival, just like free pipe. This is interpreted as a liquid-filled microannulus about 0.1 mm thick. The immunity of the ultrasonic measurement to a liquid-filled microannulus is one of its great strengths. With the CBL alone, a repeat pressure pass would be needed to diagnose a microannulus. In the presence of a liquid-filled microannulus, the CBL amplitude is usually slightly lower than in this example, and some weak formation arrivals should be visible.

Gas channel and microannulus

This example concerns an old gas-storage well from which the gas was leaking to the surface inside a 9.625-in. casing. The USI log in the 7-in. liner indicated patches of gas microannulus and good cement with gas communication throughout. The section in Fig. 15-68 shows narrow gas channels plus large areas of gas microannulus. The well was originally cemented under gas pressure, and the CBL log generated at the time of cementation showed almost 100% bond. The interpretation is that the cement debonded from the 7-in. liner, creating a gas microannulus through which the gas escaped to the top of the liner.

Fig. 15-67. USI and CBL-VDL log showing a wet microannulus all around the pipe.

Fig. 15-68. USI log showing a gas channel and a gas microannulus.
Various materials with microdebonding processing

Before looking at examples in which the statistical microdebonding processing is useful, the method and its response will be presented. Figure 15-69 shows how different materials and bonding conditions are seen by both conventional threshold-based interpretation and by the microdebonding processing. The first four tracks are images of the impedance standard deviations computed in four directions. Curves of the average, minimum, and maximum standard deviation at each depth are overlaid on the images. Track 6 is the conventional interpreted image based on thresholds. Track 5 is the map including microdebonding logic that indicates microdebonding in green. The last track is the BI track, which shows the percentage of bonded cement, microdebonded cement, liquid, and gas.

Free pipe has impedance in the liquid range and with low standard deviations; therefore, it is unaltered by the microdebonding processing. Bonded cement has high impedance with moderately high standard deviations,
An extended gas microannulus has an impedance near zero and low standard deviations. It is also not affected by the processing (except that the centralizers can trigger artifacts). Microdebonded cement has high standard deviation, and parts of the image with low impedance (classified as liquid or gas on the conventional image) are reclassified as microdebonded cement and shown in green.

Dry microannulus, gas microannulus, and dry debonding are alternative labels for a common phenomenon that can be extensive or patchy, as shown in Figs. 15-68 to 15-71. Contrary to common belief, a dry microannulus can occur in places where gas entry is impossible, such as double-casing strings, in which the gas in the microannulus is probably water vapor.

**Patchy bond (microdebonding)**

Figure 15-70 shows part of a USI and CBL-VDL log in a well cemented with 12.0-lbm/gal high-performance low-density cement. A very good bond was achieved above X000 ft. Below this depth, the cement BI indicates 20% to 80% bond, while the VDL is variable. The conventionally interpreted USI map, produced by setting impedance thresholds (Track 3), shows patches of a gas microannulus, liquid, and cement in a distribution that

**Fig. 15-70. A USI and CBL-VDL log of microdebonded low-density cement.**
is difficult to explain physically. This appearance is typical of variable cement bonding. The microdebonding processing classifies such areas of variable impedance as weakly bonded solids (green in Track 2). The microdebonding image and the BI (Track 4) indicate 80–100% cement around the casing over much of the interval. Remaining red patches are larger areas of dry debonding and should also be counted as cement. It can be concluded that there is good zonal isolation across the interval, and a squeeze operation would not be recommended.

Gas-affected low-density cement
In this well, a 7-in. casing was cemented using 12.2lbm/gal mixed-aggregate cement. Figure 15-71 shows the USI and CBL log over a 140-ft interval with a known gas sand across the top section. The CBL BI (black line in Track 4) is near 100% over most of the interval. In the lower section, the USI log indicates 4 to 6 MRayl cement, but in the upper section the raw image (Track 1) has variable impedance from 0 to 6 MRayl. The conventional interpreted image (Track 3) shows patches of “liquid” and gas. The microdebonding processing (Track 2) indicates poorly bonded cement in the upper section, and the total-cement index (yellow plus green) in Track 4 is near 100%, agreeing with the CBL. In this example, there was a known gas source; therefore, the conclusion was that the cement bond was affected by gas influx.

Casing shape
Manufacturing patterns on the inside of forged casings often affect the cement image slightly. Figure 15-72 shows a log in which near-vertical stripes on the amplitude and internal-radius images correlate with stripes on the cement image. While it is important to recognize these artifacts, they do not impede the interpretation except in exceptional cases. Despite the strong effect shown in this example, the well-bonded cement in the upper part of the image can easily be distinguished from poorly bonded cement in the lower part. In this example, there is also some rugosity, indicated by black spots on the amplitude map and blue flags.

![Fig. 15-71. USI log showing gas-affected low-density cement.](image-url)
Deposits
Several conditions, such as corrosion, drillpipe wear, mud deposits on the low side of the hole, and cement deposits, can create the illusion of false channels or gas. Ultrasonic logs must not be interpreted blindly by looking at the final cement image; quality control checks, including casing condition, are essential.

Figure 15-73 shows a log in a high-deviation section that seemed to indicate a narrow channel on the low side of the hole. The log was oriented with the low side in the center of the image. A first repeat log showed a smaller channel, while a second repeat found the channel had almost disappeared. The casing data revealed a vertical low-amplitude streak (Track 3) coinciding with the “channel.” The conclusions were twofold. First, deposits on the low side of the hole affected the impedance measurement to create the apparent “channel.” Second, the deposits were scraped away during the logging runs by the large number of centralizers on the logging string. This example illustrates how standard quality control using the casing and repeat-pass data can prevent a false interpretation.

Fig. 15-72. USI cement log affected by casing shape and rugosity. Casing shape is shown in the internal radius image (Track 6), and it also affects the amplitude (Track 3). Rugosity appears as black spots on the amplitude image. Both effects correlate with patterns on the cement images.
Reflections from an outer casing string

The log in Fig. 15-74 was recorded in an 8.625-in. liner inside a 10.75-in. casing. Strong reflections from the outer casing created marked “galaxy” interference patterns on the narrow side of the annulus. These patterns spiral around the casing owing to uncorrected tool rotation. The patterns are best observed on the raw impedance image (Track 3). In the lower part of the image, in which there is good cement bond, the pattern occupies about half the circumference. However, in the upper part
in which there is free pipe, the pattern is narrower. Interference patterns are usually indicative of good cement, and they occur in free pipe only where the annulus is very thin. In this example, the liner was not centralized. The mean acoustic impedance (Track 4, black) is hardly affected by reflections because the interference effects balance out on average. However, the interference pattern does cause the microdebonding algorithm (green color in Tracks 5 and 6) to falsely indicate debonding in the cement map, just as it causes the false-gas (red) coloring. No reflections can occur through an extended gas microannulus, because it acts as a barrier to ultrasound.

Fig. 15-74. USI log showing interference patterns resulting from reflections from an outer casing string through mud (top) and cement (bottom).
15-5 Conclusions

The acoustic impedance of the material in the annulus is one of many parameters that influences acoustic measurements. In particular, both sonic and ultrasonic tools are sensitive to the bond between the material and the pipe, but in different ways. Ultrasonic logs are generally easier to interpret and less ambiguous than sonic logs, but the combination of sonic and ultrasonic cement logs provides more information than either log alone. For optimal evaluation, knowledge of well data, cement job events, and pre- and postjob well histories is vital.

15-6 Acronym list

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>AI</td>
<td>Acoustic impedance</td>
</tr>
<tr>
<td>API</td>
<td>American Petroleum Institute</td>
</tr>
<tr>
<td>BI</td>
<td>Bond index</td>
</tr>
<tr>
<td>BPI</td>
<td>Percentage bonding</td>
</tr>
<tr>
<td>BWOC</td>
<td>By weight of cement</td>
</tr>
<tr>
<td>BWOW</td>
<td>By weight of water</td>
</tr>
<tr>
<td>CBL</td>
<td>Cement bond logs</td>
</tr>
<tr>
<td>DST</td>
<td>Drillstem test</td>
</tr>
<tr>
<td>FPM</td>
<td>Fluid properties measurement</td>
</tr>
<tr>
<td>OBM</td>
<td>Oil-base mud</td>
</tr>
<tr>
<td>OD</td>
<td>Outside diameter</td>
</tr>
<tr>
<td>PIT</td>
<td>Pressure-integrity test</td>
</tr>
<tr>
<td>TT</td>
<td>Transit time</td>
</tr>
<tr>
<td>VDL</td>
<td>Variable-density log</td>
</tr>
<tr>
<td>WBM</td>
<td>Water-base mud</td>
</tr>
</tbody>
</table>
For symbol definitions, please see the nomenclature, p. 679.

### Table A-1. Definitions of the Main Parameters

<table>
<thead>
<tr>
<th></th>
<th>Pipe Flow</th>
<th>Annular Flow Slot Approximation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fanning friction factor</td>
<td>$f_p = b \frac{2 \tau_w}{\rho (\psi^2)}$</td>
<td>$f_p = b \frac{2 \tau_w}{\rho (\psi^2)}$</td>
</tr>
<tr>
<td>where</td>
<td>$b^1 = 154.84$</td>
<td>$b = 154.84$</td>
</tr>
<tr>
<td>shear stress at the wall</td>
<td>$\tau_w = b \frac{d_w}{4} \frac{d \rho}{d z} \psi$</td>
<td>$\tau_w = b \frac{d_w - d_w}{4} \frac{d \rho}{d z} \psi$</td>
</tr>
<tr>
<td></td>
<td>$b = 1.2$</td>
<td>$b = 1.2$</td>
</tr>
<tr>
<td>and fluid mean velocity</td>
<td>$\psi = b \frac{4q}{\pi (d_w)^2}$</td>
<td>$\psi = b \frac{4q}{\pi (d_w)^2}$</td>
</tr>
<tr>
<td></td>
<td>$b = 808.50$</td>
<td>$b = 808.50$</td>
</tr>
<tr>
<td>Reynolds number in laminar flow</td>
<td>$(N_{Re})_{MR} = \frac{16}{f_p}$</td>
<td>$(N_{Re})_{AN} = \frac{24}{f_p}$</td>
</tr>
</tbody>
</table>

$^1$ b is the oilfield unit conversion factor
Table A-2. Main Equations for Laminar Flow

<table>
<thead>
<tr>
<th></th>
<th>Pipe Flow</th>
<th>Annular Flow Slot Approximation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Newtonian shear rate</td>
<td>$\dot{\gamma}_{NW} = b \frac{8\dot{\gamma}}{d_w}$</td>
<td>$\dot{\gamma}_{NW} = \frac{b - 12 \dot{\gamma}}{d_w - d_w}$</td>
</tr>
<tr>
<td>at the wall</td>
<td>$b = 0.2$</td>
<td>$b = 0.2$</td>
</tr>
<tr>
<td>Shear rate at the wall</td>
<td>$\dot{\gamma}<em>w = \frac{3n' + 1}{4n'} \dot{\gamma}</em>{NW}$</td>
<td>$\dot{\gamma}<em>w = \frac{2n' + 1}{3n'} \dot{\gamma}</em>{NW}$</td>
</tr>
<tr>
<td>where the local</td>
<td>$n' = \frac{d\log(\tau_w)}{d\log(\dot{\gamma}_{NW})}$</td>
<td>$n' = \frac{d\log(\tau_w)}{d\log(\dot{\gamma}_{NW})}$</td>
</tr>
<tr>
<td>power-law index</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Velocity profile if $\tau(x) \leq \tau_y$</td>
<td>$v(x) = \text{constant} = b \frac{d_w}{2\tau_w} \int_{\tau_y}^{\tau_w} \dot{\gamma}(\tau)d\tau$</td>
<td>$v(x) = \text{constant} = b \frac{d_w - d_w}{4\tau_w} \int_{\tau_y}^{\tau_w} \dot{\gamma}(\tau)d\tau$</td>
</tr>
<tr>
<td>Velocity profile if $\tau(x) \geq \tau_y$</td>
<td>$v(x) = b \frac{d_w}{2\tau_w} \int_{\tau(x)}^{\tau_w} \dot{\gamma}(\tau)d\tau$</td>
<td>$v(x) = b \frac{d_w - d_w}{4\tau_w} \int_{\tau(x)}^{\tau_w} \dot{\gamma}(\tau)d\tau$</td>
</tr>
<tr>
<td>$b = 5$</td>
<td></td>
<td>$b = 5$</td>
</tr>
<tr>
<td>Note: $x$ is the</td>
<td>pipe axis, i.e.</td>
<td>plane of symmetry of the slot:</td>
</tr>
<tr>
<td>normalized distance to</td>
<td>$x = \frac{2r}{d_w}$</td>
<td>$x = \frac{2r}{d_w}$</td>
</tr>
<tr>
<td>the:</td>
<td>and shear stress at $x$ is equal to</td>
<td></td>
</tr>
<tr>
<td></td>
<td>$\tau(x) = x \tau_w$</td>
<td>$\tau(x) = x \tau_w$</td>
</tr>
<tr>
<td>Newtonian shear-rate/</td>
<td>$\dot{\gamma}<em>{NW}(\tau_w) = \frac{4}{(\tau_w)^3} \int</em>{\tau_y}^{\tau_w} \dot{\gamma}(\tau)\tau^2d\tau$</td>
<td>$\dot{\gamma}<em>{NW}(\tau_w) = \frac{3}{(\tau_w)^3} \int</em>{\tau_y}^{\tau_w} \dot{\gamma}(\tau)\tau^2d\tau$</td>
</tr>
<tr>
<td>shear-stress relationship</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*For annular flow, the integral is calculated from the plane of symmetry of the slot to one of the walls.
### Table A-3. Definition of the Local Power-Law Parameters and Friction Factor/Reynolds Number Relationships

<table>
<thead>
<tr>
<th>All flow regimes</th>
<th>Pipe Flow</th>
<th>Annular Flow Slot Approximation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Metzner and Reed Reynolds number(^1)</td>
<td>((N_{Re})_{AM} = b_1 (b_2) ^{n'} x \rho \left( \frac{P}{d_w} \right)^{2-n'} \left( \frac{d_w}{d_w'} \right)^{n''} )</td>
<td>((N_{Re})_{AN} = b_1 (b_2) ^{n'} x \rho \left( \frac{P}{d_w} \right)^{2-n'} \left( \frac{d_w}{d_w'} \right)^{n''} )</td>
</tr>
<tr>
<td>where</td>
<td></td>
<td>(b_1 = 0.00064584)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(b_2 = 5)</td>
</tr>
<tr>
<td></td>
<td>(n' = \frac{\log(\tau_w)}{\log(8\nu_{lam}/d_w)})</td>
<td>(n' = \frac{\log(\tau_w)}{\log(12\nu_{lam}/d_w)})</td>
</tr>
<tr>
<td></td>
<td>(k_{pipe} = b_1 (b_2) ^{n'} \times \tau_w \left( \frac{8\nu_{lam}}{d_w} \right)^{n''} )</td>
<td>(k_{ann} = b_1 (b_2) ^{n'} \times \tau_w \left( \frac{12\nu_{lam}}{d_w} \right)^{n''} )</td>
</tr>
<tr>
<td></td>
<td>(b_1 = 0.01)</td>
<td>(b_1 = 0.01)</td>
</tr>
<tr>
<td></td>
<td>(b_2 = 0.2)</td>
<td>(b_2 = 0.2)</td>
</tr>
<tr>
<td>Laminar flow</td>
<td>((N_{Re})<em>{AM} \leq N</em>{Re1} = 3250 - (1150 \times n'))</td>
<td>((N_{Re})<em>{AN} \leq N</em>{Re1} = 3250 - (1150 \times n'))</td>
</tr>
<tr>
<td>Fanning friction factor</td>
<td>(f_{n} = \frac{16}{(N_{Re})_{AM}})</td>
<td>(f_{n} = \frac{24}{(N_{Re})_{AN}})</td>
</tr>
<tr>
<td>Transitional flow</td>
<td>(N_{Re1} \leq (N_{Re})<em>{AM} \leq N</em>{Re2})</td>
<td>(N_{Re1} \leq (N_{Re})<em>{AN} \leq N</em>{Re2})</td>
</tr>
<tr>
<td>Fanning friction factor</td>
<td>(\log \left( \frac{f_{n2}}{f_{n1}} \right) = \log \left( \frac{f_{n2}}{f_{n1}} \right) \times \log \left( \frac{(N_{Re})<em>{AM}}{N</em>{Re1}} \right) )</td>
<td>(\log \left( \frac{f_{n2}}{f_{n1}} \right) = \log \left( \frac{f_{n2}}{f_{n1}} \right) \times \log \left( \frac{(N_{Re})<em>{AN}}{N</em>{Re1}} \right) )</td>
</tr>
<tr>
<td>where</td>
<td>(f_{n1} = \frac{16}{N_{Re1}})</td>
<td>(f_{n1} = \frac{24}{N_{Re1}})</td>
</tr>
<tr>
<td></td>
<td>(f_{n2} = \frac{1}{\sqrt{f_{n1}}} \left[ \frac{4.0}{(n')^{0.35}} \times \log \left( N_{Re2} \times (f_{n1})^{(n')/3} \right) \right] - 0.4 )</td>
<td>(f_{n2} = \frac{1}{\sqrt{f_{n1}}} \left[ \frac{4.0}{(n')^{0.35}} \times \log \left( 2/3 \times N_{Re2} \times (f_{n1})^{(n')/3} \right) \right] - 0.4 )</td>
</tr>
<tr>
<td>Turbulent flow(^2)</td>
<td>((N_{Re})<em>{AM} \geq N</em>{Re2} = 4150 - (1150 \times n'))</td>
<td>((N_{Re})<em>{AN} \geq N</em>{Re2} = 4150 - (1150 \times n'))</td>
</tr>
<tr>
<td>Fanning friction factor</td>
<td>(1/\sqrt{f_{n}} = \left[ \frac{4.0}{(n')^{0.35}} \times \log \left( (N_{Re})<em>{AM} \times (f</em>{n})^{(n')/3} \right) \right] - 0.4 )</td>
<td>(1/\sqrt{f_{n}} = \left[ \frac{4.0}{(n')^{0.35}} \times \log \left( 2/3 \times (N_{Re})<em>{AN} \times (f</em>{n})^{(n')/3} \right) \right] - 0.4 )</td>
</tr>
</tbody>
</table>

\(^1\) \(\nu_{lam}\) is the mean velocity at which the fluid would flow (in the laminar flow regime) for a given shear stress at the wall, \(\tau_w\). If the flow regime is not laminar, this velocity is not the actual mean velocity of the fluid.

\(^2\) For low values of the local power-law index, this definition of \(N_{Re}\) can lead to inconsistent friction-factor values just above \(N_{Re}\) (see Tables A-5, A-6a, and A-7).
### Table A-4. Newtonian Fluid Relationships

<table>
<thead>
<tr>
<th>Reynolds number</th>
<th>Pipe Flow</th>
<th>Annular Flow Slot Approximation</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$N_{Re} = \frac{b \rho D_{h}^2}{\mu}$</td>
<td>$(N_{Re})<em>{AV} = \frac{b \rho D</em>{h}^2}{\mu}$</td>
</tr>
<tr>
<td></td>
<td>$b = 15.461$</td>
<td>$b = 15.461$</td>
</tr>
<tr>
<td>Laminar flow</td>
<td>$N_{Re} \leq N_{Re} = 2100$</td>
<td>$(N_{Re})<em>{AV} \leq N</em>{Re} = 2100$</td>
</tr>
<tr>
<td>Max. velocity for laminar flow</td>
<td>$V_1 = \frac{\mu N_{Re}}{\rho d_w}$</td>
<td>$V_1 = \frac{\mu N_{Re}}{\rho (d_r - d_w)}$</td>
</tr>
<tr>
<td></td>
<td>$b = 0.064677$</td>
<td>$b = 0.064677$</td>
</tr>
<tr>
<td>Fanning friction factor</td>
<td>$f_r = \frac{16}{N_{Re}}$</td>
<td>$f_r = \frac{24}{(N_{Re})_{AV}}$</td>
</tr>
<tr>
<td>Frictional pressure drop</td>
<td>$\left(\frac{dp}{dz}\right)_r = b \frac{2 \mu V^2}{(d_w)^2}$</td>
<td>$\left(\frac{dp}{dz}\right)_r = b \frac{48 \mu V^2}{(d_r - d_w)^2}$</td>
</tr>
<tr>
<td>Normalized velocity profile</td>
<td>$v(x) \frac{d}{V_r} = \frac{2}{1 - x^2}$</td>
<td>$v(x) \frac{d}{V_r} = \frac{3}{2} \frac{1 - x^2}{1 - x^2}$</td>
</tr>
<tr>
<td>Turbulent flow</td>
<td>$N_{Re} \geq N_{Re} = 3000$</td>
<td>$(N_{Re})<em>{AV} \geq N</em>{Re} = 3000$</td>
</tr>
<tr>
<td>Min. velocity for turbulent flow</td>
<td>$V_2 = \frac{\mu N_{Re}}{\rho d_w}$</td>
<td>$V_2 = \frac{\mu N_{Re}}{\rho (d_r - d_w)}$</td>
</tr>
<tr>
<td></td>
<td>$b = 0.064677$</td>
<td>$b = 0.064677$</td>
</tr>
<tr>
<td>Fanning friction factor</td>
<td>$f_r = 0.0792 \left(\frac{N_{Re}}{3000}\right)^{-0.25}$</td>
<td>$f_r = 0.0889 \left(\frac{2}{3} \frac{(N_{Re})<em>{AV}}{N</em>{Re}}\right)^{-0.38}$</td>
</tr>
<tr>
<td>Power-law approximation for $N_{Re} = 5 \leq N_{Re} \leq 10^3$</td>
<td>$f_r = 0.0792 \left(\frac{N_{Re}}{3000}\right)^{-0.25}$</td>
<td>or $f_r = 0.0982 \left(\frac{N_{Re}}{3000}\right)^{-0.26}$</td>
</tr>
<tr>
<td>Friction pressure drop using the power-law approximation</td>
<td>$\left(\frac{dp}{dz}\right)_r = b \times 1.984 \frac{0.33 \times (\rho^2)^{0.66} \times (\sigma)^{0.75}}{(d_w)^2}$</td>
<td>$\left(\frac{dp}{dz}\right)_r = b \times 4.6453 \times 10^{-7} \frac{\rho^{2.363} \times (\sigma)^{1.206} \times (d_r - d_w)^{2.435}}{\mu}$</td>
</tr>
<tr>
<td></td>
<td>$b = 0.0027141$</td>
<td>$b = 0.0029408$</td>
</tr>
<tr>
<td>Transitional flow</td>
<td>$N_{Re} \leq N_{Re} = N_{Re} = 3000$</td>
<td>$(N_{Re})<em>{AV} \leq N</em>{Re} = 3000$</td>
</tr>
<tr>
<td>Fanning friction factor</td>
<td>$\log \left(\frac{f_r}{f_{r,1}}\right) = \log \left(\frac{N_{Re}}{N_{Re}^<em>}\right) \times \log \left(\frac{N_{Re}^</em>}{N_{Re}^*}\right)$</td>
<td>$\log \left(\frac{f_r}{f_{r,1}}\right) = \log \left(\frac{N_{Re}}{N_{Re}^<em>}\right) \times \log \left(\frac{(N_{Re})<em>{AV}}{(N</em>{Re})_{AV}^</em>}\right)$</td>
</tr>
<tr>
<td>where</td>
<td>$f_{r,1} = \frac{16}{N_{Re}^*}$</td>
<td>$f_{r,1} = \frac{24}{(N_{Re})_{AV}^*}$</td>
</tr>
<tr>
<td>$\frac{1}{\sqrt{N_{Re}}^<em>} = 4.0 \times \left(\frac{N_{Re}^</em>}{N_{Re}^<em>}\right) \times \left(\frac{N_{Re}^</em>}{N_{Re}^*}\right) - 0.4$</td>
<td>$\frac{1}{\sqrt{(N_{Re})<em>{AV}}^*} = 4.0 \times \left(\frac{2}{3} \frac{(N</em>{Re})<em>{AV}}{N</em>{Re}}\right) \times \left(\frac{2}{3} \frac{(N_{Re})<em>{AV}}{N</em>{Re}}\right) - 0.4$</td>
<td></td>
</tr>
<tr>
<td>or if the power-law approximation can be used in turbulent flow</td>
<td>$f_{r,2} = 0.0792 \left(\frac{N_{Re}}{3000}\right)^{-0.25}$</td>
<td>$f_{r,2} = 0.0889 \left(\frac{2}{3} \frac{(N_{Re})<em>{AV}}{N</em>{Re}}\right)^{-0.38}$</td>
</tr>
<tr>
<td></td>
<td>$f_{r,2} = 5.2178 \times 10^{-4} \left(\frac{N_{Re}}{3000}\right)^{0.1925}$</td>
<td>$f_{r,2} = 2.3226 \times 10^{-7} \left(\frac{(N_{Re})_{AV}}{3000}\right)^{0.1925}$</td>
</tr>
<tr>
<td>Friction pressure drop using the power-law approximation in turbulent flow</td>
<td>$\left(\frac{dp}{dz}\right)_r = b \times 1.0436 \times 10^{-3} \frac{0.33 \times (\rho^2)^{0.66} \times (\sigma)^{0.75}}{(d_w)^2}$</td>
<td>$\left(\frac{dp}{dz}\right)_r = b \times 4.6453 \times 10^{-7} \frac{\rho^{2.363} \times (\sigma)^{1.206} \times (d_r - d_w)^{2.435}}{\mu}$</td>
</tr>
<tr>
<td></td>
<td>$b = 0.073064$</td>
<td>$b = 0.22259$</td>
</tr>
</tbody>
</table>

1 Defined as fluids for which $\tau = \mu = \gamma$.
### Table A-5. Power-Law Fluid Relationships

<table>
<thead>
<tr>
<th></th>
<th>Pipe Flow</th>
<th>Annular Flow Slot Approximation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reynolds number</td>
<td>( (N_{Re})<em>{MR} = \frac{b_1 (b_2)^{n} \rho (\tau)^{1/n}}{8^{1/n} \times k</em>{pipe}} )</td>
<td>( (N_{Re})<em>{AV} = \frac{b_1 (b_2)^{n} \rho (\tau)^{1/n}}{12^{1/n} \times k</em>{ann}} )</td>
</tr>
<tr>
<td>( b_1 = 0.000064584 )</td>
<td>( b_2 = 5 )</td>
<td>( b_1 = 5 )</td>
</tr>
<tr>
<td>( k_{pipe} = \left( \frac{3n+1}{4n} \right)^{n} k )</td>
<td>( k_{ann} = \left( \frac{2n+1}{3n} \right)^{n} k )</td>
<td></td>
</tr>
<tr>
<td><strong>Laminar flow</strong></td>
<td>( \left( \frac{N_{Re}}{N_{Re}} \right)_{MR} )</td>
<td>( \left( \frac{N_{Re}}{N_{Re}} \right)_{AV} )</td>
</tr>
<tr>
<td>Max. velocity for laminar flow</td>
<td>( \nabla_1 = b_1 \left( \frac{1}{2} \right)^{2-n} \left[ \frac{8^{1/n} \times k_{pipe} \times (N_{Re})_{MR}}{\rho \times (d_e)^{1/n}} \right]^{1/n} )</td>
<td>( \nabla_1 = b_1 \left( \frac{1}{2} \right)^{2-n} \left[ \frac{12^{1/n} \times k_{ann} \times (N_{Re})_{AV}}{\rho \times (d_e - d_w)^{1/n}} \right]^{1/n} )</td>
</tr>
<tr>
<td>( b_1 = 5 )</td>
<td>( b_1 = 5 )</td>
<td>( b_1 = 83.333 )</td>
</tr>
<tr>
<td>( b_2 = 619.35 )</td>
<td>( b_2 = 619.35 )</td>
<td>( b_2 = 0.2 )</td>
</tr>
<tr>
<td><strong>Fanning friction factor</strong></td>
<td>( f_r = \frac{16}{(N_{Re})_{MR}} )</td>
<td>( f_r = \frac{24}{(N_{Re})_{AV}} )</td>
</tr>
<tr>
<td>( \frac{dp}{dz} = b_1 \left( b_2 \right)^{\frac{2^{2n+1} \times k_{pipe} \times (N_{Re})_{MR}}{(d_e)^{1/n}}} \right) )</td>
<td>( \frac{dp}{dz} = b_1 \left( b_2 \right)^{\frac{2^{2n+1} \times k_{ann} \times (N_{Re})_{AV}}{(d_e - d_w)^{1/n}}} \right) )</td>
<td></td>
</tr>
<tr>
<td>( b_1 = 83.333 )</td>
<td>( b_2 = 0.2 )</td>
<td>( b_2 = 0.2 )</td>
</tr>
<tr>
<td>( b_2 = 619.35 )</td>
<td>( b_2 = 619.35 )</td>
<td></td>
</tr>
<tr>
<td><strong>Normalized velocity profile</strong></td>
<td>( \frac{v(x)}{\bar{v}} = \frac{3n+1}{n+1} \left( \frac{x}{\bar{v}} \right)^{1/n} )</td>
<td>( \frac{v(x)}{\bar{v}} = \frac{2n+1}{n+1} \left( \frac{x}{\bar{v}} \right)^{1/n} )</td>
</tr>
<tr>
<td><strong>Turbulent flow(^2)</strong></td>
<td>( \left( \frac{N_{Re}}{N_{Re}} \right)_{MR} \approx \frac{4150 - (1150 \times n)}{n} )</td>
<td>( \left( \frac{N_{Re}}{N_{Re}} \right)_{AV} \approx \frac{4150 - (1150 \times n)}{n} )</td>
</tr>
<tr>
<td>Min. velocity for turbulent flow</td>
<td>( \nabla_2 = b_1 \left( b_2 \right)^{\frac{2^{2n+1} \times k_{pipe} \times (N_{Re})_{MR}}{(d_e)^{1/n}}} \right) )</td>
<td>( \nabla_2 = b_1 \left( b_2 \right)^{\frac{2^{2n+1} \times k_{ann} \times (N_{Re})_{AV}}{(d_e - d_w)^{1/n}}} \right) )</td>
</tr>
<tr>
<td>( b_1 = 5 )</td>
<td>( b_1 = 5 )</td>
<td>( b_2 = 619.35 )</td>
</tr>
<tr>
<td>( b_2 = 619.35 )</td>
<td>( b_2 = 619.35 )</td>
<td></td>
</tr>
<tr>
<td><strong>Fanning friction factor</strong></td>
<td>( \frac{1}{\sqrt{f_r}} = \frac{4.0}{n^{0.55}} \times \log \left( \frac{(N_{Re})_{MR} \times (\tau)^{1/n}}{(d_e)^{1/n}} \right) )</td>
<td>( \frac{1}{\sqrt{f_r}} = \frac{4.0}{n^{0.55}} \times \log \left( \frac{2 \times (N_{Re})_{AV} \times (\tau)^{1/n}}{(d_e - d_w)^{1/n}} \right) )</td>
</tr>
<tr>
<td>( a(n) = 0.0792 + 0.0207 \times \log(n) )</td>
<td>( a(n) = 0.0792 + 0.0207 \times \log(n) )</td>
<td>( a(n) = 0.0792 + 0.0207 \times \log(n) )</td>
</tr>
<tr>
<td>( b(n) = -0.251 + 0.141 \times \log(n) )</td>
<td>( b(n) = -0.251 + 0.141 \times \log(n) )</td>
<td>( b(n) = -0.251 + 0.141 \times \log(n) )</td>
</tr>
</tbody>
</table>

*continued on next page*
<table>
<thead>
<tr>
<th>Table A-5. Power-Law Fluid(^1) Relationships (continued)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Pipe Flow</strong></td>
</tr>
</tbody>
</table>
| \[
\left(\frac{dp}{dz}\right)_f = \left[b_1 \times (b_2)^{u(n)} \times (b_3)^{v(n)}\right] \times \frac{2a(n) \times \mu^{1/(n+1)} \times (f_{1/2})^{1/(n+2)}}{16 \times d_{\text{m}}^{1/(n+1)}} + \frac{b_1}{0.0053820} + \frac{b_2}{6.4584 \times 10^{-5}} + b_3 \times 0.2
\]
| **Annular Flow Slot Approximation**                      |
| \[
\left(\frac{dp}{dz}\right)_f = \left[b_1 \times (b_2)^{u(n)} \times (b_3)^{v(n)}\right] \times \frac{2a(n) \times \mu^{1/(n+1)} \times (f_{1/2})^{1/(n+2)}}{16 \times d_{\text{m}}^{1/(n+1)}} + \frac{b_1}{0.0053820} + \frac{b_2}{6.4584 \times 10^{-5}} + b_3 \times 0.2
\]
| **Transitional flow**                                    |
| Fanning friction factor                                  |
| \[
\log\left(\frac{f_{1/2}}{f_{1/1}}\right) = \frac{\log\left(\frac{f_{1/2}}{f_{1/1}}\right)}{\log\left(\frac{N_{Ri1}}{N_{Ri2}}\right)} = \left(\frac{N_{Ri1}}{N_{Ri2}}\right)_{\text{AN}}
\]
| where                                                    |
| \[
1 = \frac{4.0}{n^{1/2}} \times \log\left[N_{Ri2} \times \left(f_{1/2}\right)^{1/(n+1)}\right] - 0.4
\]
| or if the power-law approximation can be used in turbulent flow |
| \[
f_{1/2} = a(n) \times \left[N_{Ri2}\right]^{1/(n+1)}
\]
| \[
f_{1/2} = c(n) \times \left[N_{Ri2}\right]^{1/(n+1)}
\]
| \[
\log\left(a(n) \times N_{Ri1} \times \left[N_{Ri2}\right]^{1/(n+1)}\right) = \frac{16}{\log\left(N_{Ri2}/N_{Ri1}\right)}
\]
| \[
c(n) = \frac{16}{\left[N_{Ri1}\right]^{1/(n+1)}}
\]

---

\(^1\) Defined as fluids for which \(v = k\).  
\(^2\) For low values of the power-law index, this definition of \(N_{Ri}\) can lead to friction-factor values just above \(N_{Re}\) that are lower than those given by the laminar flow equation. 
This is physically impossible. This problem can be solved by imposing \(N_{Re}\) values that are always larger than those defined by the point of intersection of the friction-factor/Reynolds-number curves in laminar and turbulent flow.
Table A-6a. Bingham Plastic Fluid Relationships

<table>
<thead>
<tr>
<th>Description</th>
<th>Pipe Flow</th>
<th>Annular Flow Slot Approximation</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Bingham Reynolds number</strong></td>
<td>((N_{BR})_{BG} = b \times \frac{\rho \times \nabla \times \mathbf{d}_w}{\mu_p})</td>
<td>((N_{BR})_{BG} = b \times \frac{\rho \times \nabla \times (\mathbf{d}_w - \mathbf{d}_w)}{\mu_p})</td>
</tr>
<tr>
<td></td>
<td>(b = 15.461)</td>
<td>(b = 15.461)</td>
</tr>
<tr>
<td><strong>Hedström number</strong></td>
<td>(N_{He} = b \times \frac{\rho \times (\mathbf{d}_w)^2 \times \tau_v}{(\mu_p)^2})</td>
<td>(N_{He} = b \times \frac{\rho \times (\mathbf{d}_w - \mathbf{d}_w)^2 \times \tau_v}{(\mu_p)^2})</td>
</tr>
<tr>
<td></td>
<td>(b = 37,015)</td>
<td>(b = 37,015)</td>
</tr>
<tr>
<td>Dimensionless shear stress</td>
<td>(\psi = \frac{\tau_v}{\tau_{sw}})</td>
<td>(\psi = \frac{\tau_v}{\tau_{sw}})</td>
</tr>
</tbody>
</table>

**All flow regimes**

- **Local power law**
  \[ n' = \frac{1 - \psi \left( 1 + \frac{2}{3} \psi + \frac{1}{3} \psi^2 \right)}{1 + \psi \left( 1 + \psi^2 \right)} \]
  \[ n' = \frac{1 - \psi \left( 1 + \frac{1}{2} \psi \right)}{1 + \psi + \psi^2} \]

- **Consistency index**
  \[ k_{pipe} = b_1 (b_2)^n \left( \frac{\tau_v}{\psi} \right)^{1/n'} \left( \frac{\mu_p}{1 - \frac{2}{3} \psi + \frac{1}{3} \psi^2} \right)^{n''} \]
  \[ k_{ann} = b_1 (b_2)^n \left( \frac{\tau_v}{\psi} \right)^{1/n'} \left( \frac{\mu_p}{1 - \frac{2}{3} \psi + \frac{1}{3} \psi^2} \right)^{n''} \]

- **Bingham plastic fluid**
  \[ b_1 = 0.01 \]
  \[ b_2 = 0.0020885 \]

**Laminar flow**

\[ (N_{BR})_{MR} \leq N_{Rl} = 3250 - (1150 \times n') \]
\[ (N_{BR})_{AV} \leq N_{Rl} = 3250 - (1150 \times n') \]

- **Fanning friction factor**
  \[ f_r = \frac{16}{(N_{BR})_{MR}} \]
  \[ f_r = \frac{24}{(N_{BR})_{AV}} \]

- **Frictional pressure drop**
  \[ \dot{\gamma}_{AV} = b \times \frac{\tau_v \psi}{\mu_p} \left( 1 - \frac{4}{3} \psi + \frac{1}{3} \psi^2 \right) \]
  \[ b = 478.80 \]
  \[ \dot{\gamma}_{AV} = b \times \frac{\tau_v \psi}{\mu_p} \left( 1 - \frac{3}{2} \psi + \frac{1}{2} \psi^2 \right) \]
  \[ b = 478.80 \]

- **Normalized velocity profile**
  \[ \frac{v(x)}{\bar{v}} = \begin{cases} \frac{1 - \psi^2 - (x - \bar{x})^2}{1 - \frac{4}{3} \psi + \frac{1}{3} \psi^2} & \text{when } \tau_v \geq \tau_r \\ \frac{2}{1 + \frac{2}{3} \psi + \frac{1}{3} \psi^2} & \text{when } \tau_v \leq \tau_r \end{cases} \]
  \[ \frac{v(x)}{\bar{v}} = \begin{cases} 3 \left( 1 - \psi^2 - (x - \bar{x})^2 \right) & \text{when } \tau_v \geq \tau_r \\ \frac{3}{2} \left( 1 - \frac{3}{2} \psi + \frac{1}{2} \psi^2 \right) & \text{when } \tau_v \leq \tau_r \end{cases} \]

**Other flow regimes**

\[ (N_{BR})_{MR} \geq N_{Rl} = 3250 - (1150 \times n') \]
\[ (N_{BR})_{AV} \geq N_{Rl} = 3250 - (1150 \times n') \]

---

1 Defined as fluids for which \( \tau_v = \mu_p \times \psi \).

2 Flow equations are solved numerically using the local power-law approach.

3 For high values of the Hedström number, the definition of \( N_{He} \) can lead to Bingham plastic Reynolds-number values that do not increase continuously when the dimensionless shear stress, \( \psi \), decreases from 1 to 0. This is not physically sound; however, in practice this is not a problem because it is nearly impossible to reach turbulence when the Hedström number is relatively high. If necessary, \( N_{He} \) values that are much higher than those given by the proposed linear equation should be used for low values of the local power index.
Table A-6b. Approximations for Bingham Plastic Fluids when $\psi << 1$

<table>
<thead>
<tr>
<th>Reynolds number</th>
<th>Pipe Flow</th>
<th>Annular Flow Slot Approximation</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$(N_{Re})<em>{AR} = \frac{(N</em>{Re})<em>{BG}}{1 + \frac{N</em>{Re}}{6(N_{Re})_{BG}}}$</td>
<td>$(N_{Re})<em>{AN} = \frac{(N</em>{Re})<em>{BG}}{1 + \frac{N</em>{Re}}{8(N_{Re})_{BG}}}$</td>
</tr>
<tr>
<td>Laminar flow</td>
<td>$(N_{Re})<em>{AR} \leq N</em>{Re1} = 3250 - (1150 \times n')$</td>
<td>$(N_{Re})<em>{AN} \leq N</em>{Re1} = 3250 - (1150 \times n')$</td>
</tr>
<tr>
<td>Local power-law index</td>
<td>$n' = 1 - \frac{1}{1 + \frac{6(N_{Re})<em>{BG}}{N</em>{Re}}}$</td>
<td>$n' = 1 - \frac{1}{1 + \frac{8(N_{Re})<em>{BG}}{N</em>{Re}}}$</td>
</tr>
<tr>
<td>Max. velocity for laminar flow</td>
<td>$\bar{v}<em>1 = b \times \frac{\mu_p \times N</em>{Re1}}{2 \times p \times d_w} \left(1 + \sqrt{\frac{2N_{Re}}{3N_{Re1}}}\right)$</td>
<td>$\bar{v}<em>1 = b \times \frac{\mu_p \times N</em>{Re1}}{2 \times p \times (d_o - d_w)} \left(1 + \sqrt{\frac{N_{Re}}{2N_{Re1}}}\right)$</td>
</tr>
<tr>
<td>Frictional pressure drop</td>
<td>$b_1 = 0.064677$</td>
<td>$b = 0.064677$</td>
</tr>
</tbody>
</table>

Frictional pressure drop

$b_1 = 0.00034809$

$b_2 = 0.83333$

$b_1 = 0.00034809$

$b_2 = 0.83333$

Other flow regimes†

$(N_{Re})_{AR} \geq N_{Re1} = 3250 - (1150 \times n')$  $(N_{Re})_{AN} \geq N_{Re1} = 3250 - (1150 \times n')$

† Flow equations are solved numerically using the local power-law approach.
### Table A-7. Herschel-Bulkley Fluid\(^*\) Relationships

<table>
<thead>
<tr>
<th>Dimensionless shear stress</th>
<th>Pipe Flow</th>
<th>Annular Flow Slot Approximation</th>
</tr>
</thead>
<tbody>
<tr>
<td>All flow regimes</td>
<td>(\psi = \frac{\tau_y}{\tau_w})</td>
<td>(\psi = \frac{\tau_y}{\tau_w})</td>
</tr>
</tbody>
</table>
| Local power-law index     | \(n' = n(1 - \psi)\times\) \[
\frac{(n+1)(2n+1)+2n(n+1)\psi+2n^2\psi^2}{(n+1)(2n+1)+3n(n+1)\psi+6n^2\psi^2+6n^4\psi^2}\]
|                           | \(n' = n(1 - \psi)^{1+\frac{1}{n}}\times\) \[
\frac{3n(1 - \psi)^{\frac{1}{n}}}{(n+1)(2n+1)^{\frac{1}{n}}}\]
| Laminar flow              | \((N_{Re,l})_{th} \leq N_{Re,l} = 3250 - (1150 \times n')\) | \((N_{Re,AW})_{AW} \leq N_{Re,l} = 3250 - (1150 \times n')\) |
| Frictional pressure drop  | \(\dot{\gamma}_{NW} = b^n \times \left(\frac{\tau_y}{k}\right)^{\frac{1}{n}} \left[\frac{4n(1 - \psi)^{1+\frac{1}{n}}}{\psi^{\frac{1}{n}}}\right] \times \left[\frac{(1 - \psi)^2}{3n+1} + 2\psi(1 - \psi) + \psi^2\right] \times \left[\frac{2n+1}{1+n+2n^2\psi^2}\right] + \psi^2\]
|                           | \(b = 0.01\) | \(b = 0.01\) |
| Normalized velocity profile when \(\tau_s \geq \tau_y\) \(v(x) = \frac{1}{\dot{\gamma}}\left[\frac{x - \psi}{(1 - \psi)}\right]^{\frac{1}{n}}\times\) \[
\frac{n+1}{3n+1}(1 - \psi)^{\frac{1}{n}} + \frac{2(n+1)}{2n+1}(\psi(1 - \psi) + \psi^2)\]
| and when \(\tau_s \leq \tau_y\) \(v(x) = \frac{1}{\dot{\gamma}}\left[\frac{2(n+1)(3n+1)}{(n+1)(2n+1)} + \frac{2n(n+1)\psi + 2n^2\psi^2}{1+n+2n^2\psi^2}\right] + \psi^2\]
| Other flow regimes\(^*\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,\,
\]
|                           | \((N_{Re,AW})_{AW} \geq N_{Re,l} = 3250 - (1150 \times n')\) | \((N_{Re,AW})_{AW} \geq N_{Re,l} = 3250 - (1150 \times n')\) |

\(^{*}\) Defined as fluids for which \(\tau = \tau_y + k \times \dot{\gamma}\).

\(^{*}\) Flow equations are solved numerically using the local power-law approach.

\(^{*}\) For low values of the power-law index, this definition of \(N_{Re,AW}\) can lead to predictions of friction factors that are not physically sound. The problem can be solved by using much higher \(N_{Re,AW}\) values than those given by the proposed linear equation.
<table>
<thead>
<tr>
<th>Table A-8. Dimensionless Breakthrough Time and Circulation Efficiency in Laminar Flow</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Dimensionless time</strong></td>
</tr>
<tr>
<td>$t^* = \frac{\bar{V} \times t}{L}$</td>
</tr>
<tr>
<td><strong>Additional parameter</strong></td>
</tr>
<tr>
<td><em><em>Circulation efficiency for $t^</em> \leq t^</em>_{\text{break}}$**</td>
</tr>
<tr>
<td><strong>Newtonian fluids</strong></td>
</tr>
<tr>
<td>Dimensionless breakthrough time</td>
</tr>
<tr>
<td>Circulation efficiency for $t^* \geq t^*_{\text{break}}$</td>
</tr>
<tr>
<td><strong>Power-law fluids</strong></td>
</tr>
<tr>
<td>Dimensionless breakthrough time</td>
</tr>
<tr>
<td>Circulation efficiency for $t^* \geq t^*_{\text{break}}$</td>
</tr>
<tr>
<td><strong>Bingham plastic fluids</strong></td>
</tr>
<tr>
<td>Dimensionless breakthrough time</td>
</tr>
<tr>
<td>Circulation efficiency for $t^* \geq t^*_{\text{break}}$</td>
</tr>
<tr>
<td><strong>Herschel-Bulkley fluids</strong></td>
</tr>
<tr>
<td>Dimensionless breakthrough time</td>
</tr>
<tr>
<td>Circulation efficiency for $t^* \geq t^*_{\text{break}}$</td>
</tr>
</tbody>
</table>
A-1 Application of the local-power approach to Bingham plastic fluids

As an example of the application of the local-power model to the flow of non-Newtonian fluids in transitional and turbulent flow, the equations governing the flow of Bingham plastic fluids will be described hereafter. It will be assumed that the friction factor/Reynolds number relationship in turbulent flow can be described by a power-law approximation.

For flow in a pipe, the main equations are the following.

a) To determine the end of the laminar flow regime, it is necessary to solve for \( \psi_1 \) using the following set of equations.

\[
N_{Re1}(n') = \frac{N_{He}}{8\psi_1}[1 - \frac{4}{3} \psi_1 + \frac{1}{3}(\psi_1)^4]^2
\]

\[
N_{Re1}(n') = 3250 - (1150 \times n')
\]

\[
n' = \frac{(1 - \psi_1)[1 + \frac{2}{3} \psi_1 + \frac{1}{3}(\psi_1)^2]}{(1 + \psi_1)[1 + (\psi_1)^2]}
\]

These three equations can be combined into one:

\[
\frac{N_{He}}{8\psi_1}[1 - \frac{4}{3} \psi_1 + \frac{1}{3}(\psi_1)^4]^2 = 3250 - 1150
\]

\[
\times \frac{(1 - \psi_1)[1 + \frac{2}{3} \psi_1 + \frac{1}{3}(\psi_1)^2]}{(1 + \psi_1)[1 + (\psi_1)^2]}
\]

Once the value of \( \psi_1 \) is determined, the maximum velocity for the flow regime to be laminar can be derived from

\[
(N_{Re})_{BG1} = \frac{N_{He}}{8\psi_1}[1 - \frac{4}{3} \psi_1 + \frac{1}{3}(\psi_1)^4].
\]

b) To determine the beginning of the turbulent flow regime, it is necessary to solve for \( \psi_2 \) using the following set of equations (assuming the Fanning friction factor/Reynolds number relationship in turbulent flow can be described by a power-law relationship).

\[
N_{Re2}(n') = \left\{ \frac{16}{a(n')} \right\}^{\frac{1}{2-n'}}
\]

\[
\times \left[ \frac{N_{He}}{8\psi_2} \left[ 1 - \frac{4}{3} \psi_2 + \frac{1}{3}(\psi_2)^4 \right] \right]^{\frac{1}{2-n'}}
\]

\[
n' = \frac{1}{1 + \frac{2}{3} \psi_2 + \frac{1}{3}(\psi_2)^2}
\]

\[
\times \left( 1 + \psi_2 \right)^{\frac{1}{2 + (2-n)b(n')}}
\]

\[
\times \left[ 1 - \frac{4}{3} \psi_2 + \frac{1}{3}(\psi_2)^4 \right]^{\frac{1}{2 + (2-n)b(n')}}
\]

\[
a(n') = 0.0792 + 0.0207 \log(n')
\]

\[
b(n') = -0.251 + 0.141 \log(n')
\]

Once the value of \( \psi_2 \) is determined, the corresponding values for \( n' \), \( a(n') \), and \( b(n') \) can be calculated and the maximum velocity for the flow regime to be laminar can be derived from

\[
(N_{Re})_{BG2} = \left\{ \frac{N_{He}}{8\psi_2} \right\}^{1 + (1-n')b(n')}
\]

\[
\times \left[ \frac{16}{a(n')} \right]^{\frac{1}{2 + (2-n)b(n')}}
\]

\[
\times \left[ 1 - \frac{4}{3} \psi_2 + \frac{1}{3}(\psi_2)^4 \right]^{\frac{1}{2 + (2-n)b(n')}}
\]

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c) The friction pressure drop in turbulent flow can be derived from

\[
(N_{Re})_{BG} = \left( \frac{N_{He}}{8 \psi} \right)^{1+(1-n')b(n')} \cdot \frac{1}{2+2(2-n')b(n')} \times \left( \frac{1}{3 \psi + \frac{1}{3} \psi^4} \right)^{n'b(n')}
\]

\[
(N_{Re})_{BG} = \left( \frac{N_{Re1}}{N_{Re1}^{1+d}} \right) \times \left( \frac{f_{fr2}}{f_{fr1}} \right) \log \left( \frac{N_{Re2}}{N_{Re1}} \right)
\]

For flow in a narrow concentric annulus, the main equations are the following.

e) To determine the end of the laminar flow regime, it is necessary to solve for \( \psi_1 \) using the following set of equations.

\[
N_{Re1}(n') = \frac{N_{He}}{12\psi} \left[ 1 - \frac{3}{2} \psi_1 + \frac{1}{2} (\psi_1)^3 \right]^2
\]

\[
N_{Re1} (n') = 3250 - (1150 \times n')
\]

\[
n' = \frac{(1 - \psi_1)(1 + \frac{1}{2} \psi_1)}{1 + \psi_1 + (\psi_1)^2}
\]

These three equations can be combined into one:

\[
N_{He} \left[ 1 - \frac{3}{2} \psi_1 + \frac{1}{2} (\psi_1)^3 \right]^2 = 3250 \left[ \frac{(1 - \psi_1)(1 + \frac{1}{2} \psi_1)}{1 + \psi_1 + (\psi_1)^2} \right]
\]

Once the value of \( \psi_1 \) is determined, the maximum velocity for the flow regime to be laminar can be derived from

\[
(N_{Re})_{BG1} = \frac{N_{He}}{12\psi} \left[ 1 - \frac{3}{2} \psi_1 + \frac{1}{2} (\psi_1)^3 \right].
\]

d) The friction pressure drop in transitional flow can be derived from

f) To determine the beginning of the turbulent flow regime, one must solve for \( \psi_2 \) using the following set of equations (assuming the Fanning fraction/Reynolds number relationship in turbulent flow can be described by a power-law relationship).

\[
N_{Re2}(n') = \left( \frac{24}{a(n')} \right)^{b(n')} \left( \frac{3}{2} \right)^{-n'} \times \left( \frac{N_{He}}{12\psi} \left[ 1 - \frac{3}{2} \psi_2 + \frac{1}{2} (\psi_2)^3 \right] \right)^{n'}
\]

\[
N_{Re1}(n') = 4150 - (1150 \times n')
\]

\[
n' = \frac{(1 - \psi_2)(1 + \frac{1}{2} \psi_2)}{1 + \psi_2 + (\psi_2)^2}
\]

\[
a(n') = 0.0883 + 0.0246 \times \log(n')
\]

\[
b(n') = -0.263 + 0.138 \times \log(n')
\]

Once the value of \( \psi_2 \) is determined, the corresponding values for \( n', a(n'), \) and \( b(n') \) can be calculated and the maximum velocity for the flow regime to be laminar can be derived from

\[
(N_{Re})_{BG2} = \left( \frac{3}{2} \right)^{b(n')} \times \left( \frac{N_{He}}{12\psi_2} \right)^{1+(1-n')b(n')} \times \left( \frac{1}{2+2(2-n')b(n')} \right) \times \left( \frac{f_{fr2}}{f_{fr1}} \right) \log \left( \frac{N_{Re2}}{N_{Re1}} \right)
\]
g) Friction pressure drop in turbulent flow can be derived from

\[
\left( N_{Re} \right)_{BG} = \left\{ \frac{3}{2} \times \left( \frac{N_{He}}{12 \psi} \right) \left[ \frac{24}{a(n')} \right] \left( 1 - \frac{3}{2} \psi + \frac{1}{2} \psi^3 \right)^{n'(n')} \right\}^{1+(1-n')(n')} \left( \frac{1}{2(2-n')^2} \right).
\]

h) Friction pressure drop in transitional flow can be derived from

\[
\left( N_{Re} \right)_{BG} = \left\{ \frac{N_{He}}{12 \psi} \right\}^{1+(1-n')d} \times \left( \frac{N_{Re1}}{N_{Re2}} \right)^{1+d} \left( 1 - \frac{3}{2} \psi + \frac{1}{2} \psi^3 \right)^{n'd} \left( \frac{1}{2(2-n')^2} \right).
\]

\[
d = \log \left( \frac{f_{fr2}}{f_{fr1}} \right) \div \log \left( \frac{N_{Re2}}{N_{Re1}} \right).
\]

A-2 Conversion factors

The \( b \) coefficients in oilfield units were determined using the following primary conversion factors.

<table>
<thead>
<tr>
<th>Unit</th>
<th>To be Multiplied by</th>
<th>To Get Value in SI Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>bbl</td>
<td>0.1589873</td>
<td>m³</td>
</tr>
<tr>
<td>cp</td>
<td>0.001</td>
<td>Pa·s</td>
</tr>
<tr>
<td>ft</td>
<td>0.3048</td>
<td>m</td>
</tr>
<tr>
<td>gal</td>
<td>0.003785412</td>
<td>m³</td>
</tr>
<tr>
<td>in.</td>
<td>0.0254</td>
<td>m</td>
</tr>
<tr>
<td>lbm</td>
<td>0.45359237</td>
<td>kg</td>
</tr>
</tbody>
</table>

Coefficients equal to 1 are not reported. For SI units, \( b \) coefficients are always equal to 1. The acceleration of gravity is \( 9.80665 \text{ m·s}^{-2} \).

In this appendix, oilfield units are expressed as follows.

Oilfield Unit Clarification

<table>
<thead>
<tr>
<th>Unit</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Diameter</td>
<td>in.</td>
</tr>
<tr>
<td>Length</td>
<td>ft</td>
</tr>
<tr>
<td>Velocity</td>
<td>ft/min</td>
</tr>
<tr>
<td>Flow rate</td>
<td>bbl/min</td>
</tr>
<tr>
<td>Friction pressure gradient</td>
<td>psi/1,000 ft</td>
</tr>
<tr>
<td>Pressure</td>
<td>psi</td>
</tr>
<tr>
<td>Stress</td>
<td>lbf/100 ft²</td>
</tr>
<tr>
<td>Density</td>
<td>lbm/gal</td>
</tr>
<tr>
<td>Viscosity</td>
<td>cp</td>
</tr>
<tr>
<td>Consistency index</td>
<td>lbf·s⁹/ft³</td>
</tr>
</tbody>
</table>
B-1 Introduction

Laboratory testing of cements and cementing materials is an essential part of the cementing process. Testing begins at the cement and additive manufacturing sites to monitor product quality and continues through the slurry-design stages at the pumping service company or operating company laboratories. Samples are frequently obtained from the bulk plant as the blend is prepared, and samples are taken from storage silos when the blend is placed on location. Field samples of the dry cement blends and the resulting slurries can be obtained during mixing for subsequent evaluation, either in the laboratory or on location using portable laboratory equipment. Laboratory examination of samples obtained from the field can be used for post-treatment investigations.

In general, there are two types of laboratory testing of cements and cementing materials: performance evaluation and chemical characterization. The typical oilfield laboratory primarily evaluates cement performance through physical measurement of specific slurry and set-cement properties under simulated downhole conditions. This type of evaluation occurs mainly during the slurry-design and execution stages of a cementing treatment. Chemical characterization typically involves quantitative or qualitative analysis of the slurry components before and after mixing to ensure their suitability for use. Analytical techniques are used for quality-control purposes at the point of manufacture to determine that components of a dry-blended cement system are present in the desired quantities and are blended thoroughly at the bulk plant. Such techniques are also used to monitor the quality of the mix water on location. Correct application of a wide variety of laboratory testing methods helps achieve a successful cementing treatment.

This appendix presents a broad overview of laboratory testing procedures and equipment for cement testing. Most of these techniques are readily available in most well-equipped cement-testing laboratories. In addition, a few test methods are presented that are currently in the domain of research laboratories but may become more common in the future.

This appendix is not intended to be a manual for cement laboratory workers. The reader must instead consult the official publications of organizations such as the American Petroleum Institute (API), the International Organization for Standardization (ISO), or ASTM International (formerly the American Society for Testing and Materials) for such guidance.

B-2 Relationship between the API and the ISO

The API Committee on Standardization of Well Cements (Committee 10) acts as a governing body regarding the development of standardized testing procedures for evaluation of the performance of well cement slurries. The procedures are published by API as API Specification 10A and API Recommended Practice (RP) 10B. Equivalent publications by the ISO are ISO 10426-1 and ISO 10426-2, respectively.

Specification for Cements and Materials for Well Cementing, API Specification 10A, and ISO 10426-1 contain the requirements for eight classes of well cements, including chemical and physical requirements and specific procedures for physical testing. These standards are applicable to well cement classes A, B, C, D, E, F, G, and H (Chapter 2). These documents present tests that are to be performed on neat cement with no additives. The purpose of the specification tests is to evaluate specific chemical and performance requirements of the raw cement. The tests are highly specific, and no variance from the testing protocol is allowed.

Recommended Practice for Testing Well Cements, API RP 10B and ISO 10426-2, provides general recommended practices for testing cement slurries and related materials under simulated well conditions. These procedures are designed to simulate downhole conditions for performance testing and are based on a compromise between realistic wellbore conditions and the practical limitations of the laboratory environment.

At this writing there are three additional standards that cover special aspects of well cementing. They can be considered as supplements to API RP 10B and ISO 10426-2.

- ISO 10426-3, “Testing of deepwater well cement formulations.” In a deepwater cementing environment, a large number of factors affect the thermal history of the cement slurry (Chapter 12). These factors include...
water depth, geothermal gradient, cement mix-water temperature, bulk cement temperature, cement mixing rate, cement heat of hydration, and prior circulating and static event history. Test procedures that reflect the deepwater environment do not exist in ISO 10426-2. Therefore, this standard presents specialized sampling and testing requirements and discusses the unique downhole temperature profiles found in deepwater wells.

- **ISO 10426-4**, “Methods for atmospheric foamed cement-slurry preparation and testing.” Foamed cements are routinely used in the well cementing industry (Chapter 7). Unlike conventional cement systems, foamed cements contain a gas phase. Consequently, special laboratory preparation and testing methods are required. ISO 10426-4 describes the testing procedures to measure different properties of foamed cement, including slurry density, slurry stability, strength development, and permeability. Some testing cannot be performed directly on the foamed slurry, and the document indicates alternate methods for testing thickening time, fluid loss, and rheology.

- **ISO 10426-5**: “Test methods for determination of shrinkage and expansion of well cement formulations at atmospheric pressure.” The dimensional stability of cement slurries during hydration and after hardening is a fundamental zonal-isolation parameter. As explained elsewhere in this textbook, the lack of dimensional stability can lead to various problems including
  - a microannulus, leading to a bad bond log (Chapter 15)
  - interzonal communication (Chapter 9)
  - lack of a hydraulic seal when using cement inflated packers (Chapter 11).

ISO 10426-5 describes standard devices and techniques to evaluate internal and external dimensional changes that occur during cement-slurry hydration, setting, and hardening.

It is not the intent of the API and ISO to simulate well conditions. The goal is to provide a standard set of test procedures to allow comparison of results between various laboratories. The procedures in API RP 10B and ISO 10426-2 may be modified to match the particular well conditions and mixing methods used in the field. While the tests outlined in API RP 10B and ISO 10426-2 are applicable to field work, the engineer is responsible for determining the applicability of a particular test and determining if the results are relevant to a particular well. In the future, API will adopt all cement-related new ISO documents.

**B-3 Sample preparation**

A meaningful laboratory evaluation requires a representative sample of that material. Statistical considerations regarding the choice of sample size may be found in the ASTM Standard C183, *Standard Practice for Sampling and the Amount of Testing of Hydraulic Cement*. Sampling and handling procedures for sacked and bulk cement are described in API RP 10B. The use of proper storage procedures is particularly important to avoid exposure of the cement to moisture and carbon dioxide in the air. Several studies regarding the sampling of blended cements have been reported (Pace *et al.*, 1984; Cobb and Pace, 1985; Gerke *et al.*, 1985; Kunze, 1986; Bell *et al.*, 1988).

The preferred sampling device for blended cements is a diverted flow sampler (Fig. B-1), which permits sampling from a complete cross section of a flowing stream of material. Before testing in the laboratory, field blend samples may be split using a mechanical splitter as described in ASTM Specification C702, *Standard Practice for Reducing Samples of Aggregate to Testing Size*, because segregation of blended components may occur during shipping to the laboratory. Similarly, a mechanical splitter may be appropriate for use in obtaining laboratory samples from bulk or sack quantities of multicomponent additives in the field.

![Fig. B-1. Diverted flow sampler (top view).](image)

**B-4 Performance of conventional cement slurries**

**B-4.1 Slurry preparation**

The equipment specification and operational procedures for the preparation of well-cement slurries in the laboratory are contained in API RP 10B. The mixing
device is a two-speed, propeller-type mixer, shown in Fig. B-2. Specifications are given for the propeller speeds, mixer blade wear, batch size, and mixing time. Usually, 600 mL of slurry are prepared. The mixer is operated at 4,000 rpm for 15 sec (during which all of the cement solids should be added to the mix water), followed by 35 sec at 12,000 rpm. Cement slurries are very abrasive; therefore, careful monitoring of the mixer blade condition is essential.

With this method, dry materials are uniformly blended with the cement before addition to the mixing fluid (mix water plus any liquid additives). If liquid additives are present, they should be thoroughly dispersed in the mix water before the cement is added. In certain cases, the order of liquid-additive addition to the mix water may be critical. Such special mixing procedures and mixing times should be documented. Variations in mixing procedures can significantly alter the resulting slurry properties (Roy and Asaga, 1979); therefore, individual laboratories should establish and adhere to supplemental procedures covering items not specifically addressed by API RP 10B. Variations in field mixing procedures can produce differences in slurry properties at the wellsite, and attempts are continually being made to define and improve the correlation between field mixing procedures and those used in the laboratory.

If the slurry is going to be batch mixed during the cementing operation, it should be transferred to a consistometer (Section B-4.2) and stirred in a manner consistent with the expected wellsite conditions of time and temperature.

The slurry mixing procedure specified by the API and ISO is not suitable for ultralow-density systems containing microspheres or nitrogen as extenders (Chapters 3 and 7). Hollow microspheres are easily broken under high shear; consequently, the mixer is typically operated at or below 4,000 rpm. A typical mixing procedure for slurries containing microspheres involves adding the solids to the mix fluid within 30 sec at 4,000 rpm, followed by an additional 300 sec of mixing at 4,000 rpm. Foamed cements are routinely prepared in the mixing devices depicted in Fig. B-2. A special multiblade assembly can also be employed (Fig. B-3). A base cement slurry containing surfactant is placed in the blending container, the container is capped and sealed, and the mixing device is operated at a high propeller speed until the resulting foam completely fills the mixer bowl. The foamed cement density and quality is varied by adjusting the volume of base slurry added to the blending container. The disadvantage of this procedure is that the foam is not prepared under simulated high-pressure field conditions.

Fig. B-2. Propeller-type mixing device commonly used to prepare well-cement slurries (photos courtesy Chandler Engineering, LLC, and OFI Testing Equipment, Inc.).
However, some pressurized testing methods were developed by de Rozières and Ferrière (1990). They are described in Chapter 7.

B-4.2 Slurry density
An operational procedure for determining slurry density is found in API RP 10B. The procedure uses a pressurized fluid density balance, shown in Fig. B-4. Slurry is poured into the cup and a pressure cap is screwed on. A pressurizing plunger filled with slurry (similar in operation to a syringe) is attached to the cap, and pressure is applied to collapse air bubbles entrained in the slurry. Then the device is placed on a fulcrum, and a sliding weight is adjusted until both sides are balanced. The slide is calibrated in units of slurry density.

B-4.3 Thickening time
Thickening-time tests are designed to determine the length of time a cement slurry remains in a pumpable, fluid state under simulated wellbore conditions of temperature and pressure. The operational procedures for determining the thickening time are contained in API RP 10B.

The test slurry is evaluated in a pressurized consistometer, shown in Fig. B-5, which measures the consist-
tency of the test slurry contained in a rotating cup while under simulated wellbore conditions. Most apparatuses are capable of exposing cement slurries to a maximum temperature and pressure of 400°F and 25,000 psi [204°C and 175 MPa]; however, special units capable of 700°F and 40,000 psi [371°C and 280 MPa] are available for simulating very high-temperature, very high-pressure applications. A smaller, portable consistometer that uses a rotating paddle in a stationary cup is also available (Fig. B-6). A nonpressurized, or “atmospheric,” consistometer (Fig. B-7) can be used to obtain a thickening time for low-temperature cement systems; however, today it is most commonly used for conditioning of slurries (according to various API/ISO procedures) before rheology, fluid-loss, or free-fluid tests.

The consistency of the slurry is measured in Bearden units ($B_c$), a dimensionless quantity with no direct conversion factor to more common units of viscosity, such as

Fig. B-6. Portable pressurized consistometers (photos courtesy Chandler Engineering, LLC, and OFI Testing Equipment, Inc.)

Fig. B-7. Atmospheric consistometers (photos courtesy Cement Test Equipment, Inc., Chandler Engineering, LLC, and OFI Testing Equipment, Inc.)
Pa-s or poise. The end of a thickening-time test occurs when the cement slurry reaches a consistency of 100 Bc; however, 70 Bc is generally considered to be the maximum pumpable consistency. Figure B-8 shows the output from a typical thickening-time test. Thickening-time consistency profiles often begin with a flat, low-consistency period that lasts a few hours. Then, as the slurry begins to set, the consistency rises with an ever-increasing slope until 100 Bc is attained. The time at which the consistency begins to increase is called the point of departure.

No provision for slurry fluid loss is made in the design of a consistometer slurry cup; therefore, the thickening time for a slurry in the wellbore may differ from that for the same slurry in the laboratory, particularly if the design specifies little or no fluid-loss control.

Temperature and pressure can have a pronounced effect on the measured thickening time. The thickening time also depends on the rate at which the final temperature and pressure are attained. During a cement job, flowing cement slurry is exposed to continuously changing pressure and temperature; consequently, measurement of the circulating-temperature and pressure profile in the wellbore can be difficult (Chapter 12). The rates depend on the well conditions and the cement-job design. Common variables that must be taken into account include well depth, geothermal gradient, anticipated job duration, and the effects of well operations performed before the cement job. API RP 10B contains testing guidelines for various types of cement jobs: primary cementing (casing and liner specifications) and squeeze cementing (continuous-pumping and hesitation).

**Primary cementing**

For many years, API RP 10B contained a collection of thickening-time schedules that specified the rates at which temperature and pressure are increased as well as the final temperature and pressure, during the thickening-time test. Such schedules were derived from field data collected from wells with different depths and temperature gradients. With the advent of computer simulators and improved instrumentation in the field to measure job parameters in real time, the primary cementing schedules have been replaced with equations to calculate a custom schedule for a particular cement job. The reader is referred to API RP 10B for a complete presentation of the equations. The complete set of data from which the equations were derived is presented in API Report 10TR3: “Technical Report on Temperatures for API Cement Operating Thickening Time Tests” (May, 1999).

![Fig. B-8. Typical thickening-time test output.](image)
An alternate method to create a primary cementing schedule is to consult tables in RP 10B that give estimated bottomhole circulating temperatures (BHCT) for wells with various depths and geothermal gradients. An example is shown in Table B-1. The thickening-time schedule is determined as follows.

1. Account for surface mixing of the slurry. If batch mixing is performed during the cementing operation, the slurry may be stirred in the consistometer to simulate the time and temperature. The time and slurry temperature may be estimated depending upon the expected conditions at the wellsite. The batch mixing simulation is performed before the start of the thickening-time test.

2. Calculate the time to displace the leading edge of the cement slurry to bottom. The rate of slurry displacement is calculated as follows.

\[
t_{\text{disp}} = \frac{V_{\text{pipe}}}{q},
\]

where

- \( q \) = rate at which the fluid slurry is pumped (m³/min)
- \( t_{\text{disp}} \) = time to displace the leading edge of cement slurry to bottom (min)
- \( V_{\text{pipe}} \) = volume of the pipe (m³).

3. Calculate the bottomhole pressure using the following equation.

\[
p_{\text{BH}} = g \times \rho_{df} \times D_{TV}
\]

where

- \( D_{TV} \) = true vertical depth at the top of the cement column (m)
- \( g \) = acceleration of free fall (m/sec²)
- \( p_{\text{BH}} \) = bottomhole pressure (kPa)
- \( \rho_{df} \) = density of drilling fluid (kg/m³).

4. Determine the starting pressure \( (p_i) \) to which the leading edge of cement slurry is subjected as it leaves the cementing head.

5. Calculate the increase in pressure (pressure-up rate) as the slurry travels to the bottom.

\[
R_{pu} = \frac{p_{\text{BH}} - p_i}{t_{\text{disp}}}
\]

where

- \( p_{\text{BH}} \) = bottomhole pressure (kPa)
- \( p_i \) = starting pressure (kPa)
- \( R_{pu} \) = pressure-up rate (kPa/min)
- \( t_{\text{disp}} \) = time to displace leading edge of cement to bottom (min).

6. Determine the BHCT by consulting the tables in API RP 10B (e.g., Table B-1).

### Table B-1. BHCT Chart for Casing Well Simulation Tests

<table>
<thead>
<tr>
<th>Temperature Gradient (°F/100 ft Depth [°C/100 m Depth])</th>
<th>1.6 [0.9]</th>
<th>2.0 [1.1]</th>
<th>2.4 [1.3]</th>
<th>2.7 [1.5]</th>
<th>3.1 [1.7]</th>
<th>3.5 [1.9]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth‡ (ft [m])</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1,000 [305]</td>
<td>80 [27]</td>
<td>80 [27]</td>
<td>80 [27]</td>
<td>80 [27]</td>
<td>80 [27]</td>
<td>80 [27]</td>
</tr>
</tbody>
</table>

† From API RP 10B-2. Reproduced courtesy of the American Petroleum Institute.

‡ True vertical depth.

§ Bottomhole circulating temperature.
7. Calculate the heat-up rate by subtracting the BHCT from ambient temperature and dividing by the time to bottom.

The highest temperature and pressure to which a given volume of slurry is exposed may not occur at the same point in the wellbore; consequently, they may not occur at the same time. Slurries that come to rest at the top of a long cement column will almost certainly have been exposed to higher temperatures and pressures as they circulated past deeper regions. According to API and ISO recommendations, if no measured data are available for the top of the cement column, then the final BHCT specified on the schedule should be maintained until the completion of the thickening-time test. If such data are available, the temperature and pressure may be changed to those at the top of the cement column, following steps described in the API and ISO recommendations.

**Squeeze cementing**

Tabular well-simulation thickening-time schedules for both continuous-pumping and hesitation squeeze treatments are presented in API RP 10B. An example is shown in Table B-2.

Predictive equations to estimate squeeze-cementing temperatures are also given in API RP 10B.

Although simulating the dynamic wellbore environment in the laboratory is difficult, refinements in procedures and improvements in testing equipment are helping to make more realistic laboratory simulations possible.

### Table B-2. Thickening-Time Schedule for a Continuous-Pumping Squeeze Well-Simulation Test†

<table>
<thead>
<tr>
<th>Temperature Gradient (<em>°F/100 ft Depth [°C/100 m Depth]</em>)</th>
<th>1.6 [0.9]</th>
<th>2.0 [1.1]</th>
<th>2.4 [1.3]</th>
<th>2.7 [1.5]</th>
<th>3.1 [1.7]</th>
<th>3.5 [1.9]</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Time (min)</strong></td>
<td><strong>Pressure (psi [kPa])</strong></td>
<td><strong>Temperature‡</strong></td>
<td><strong>Temperature‡</strong></td>
<td><strong>Temperature‡</strong></td>
<td><strong>Temperature‡</strong></td>
<td><strong>Temperature‡</strong></td>
</tr>
<tr>
<td>0</td>
<td>500 [3,400]</td>
<td>80 [27]</td>
<td>80 [27]</td>
<td>80 [27]</td>
<td>80 [27]</td>
<td>80 [27]</td>
</tr>
</tbody>
</table>

| Ramp (*°F [°C]*) | 0.00 [0.00] | 2.00 [1.11] | 3.00 [1.67] | 5.00 [2.76] | 6.00 [3.33] |

† From API RP 10B-2. Reproduced courtesy of the American Petroleum Institute.

‡ Depth: 1,000 ft [305 m] and mud density: 9.2 lbm/gal [1.10 kg/L]. Ramp time: 1 min. Temperature dwell: 14 min.
Pressure rate (per min) = 0 psi [0 kPa] for 1 min. then 20 psi (143 kPa) for 14 min.
B-4.4 Fluid loss

Fluid-loss tests measure the slurry dehydration during and immediately following a cement job. API RP 10B offers operational test procedures for determining the fluid-loss rate. After conditioning at simulated wellbore conditions, the test slurry is placed in a heated cell and subjected to 1,000 psi [6.9 MPa] of differential pressure. The filtrate loss is measured across a standard filtration medium (45-μm [325-mesh] screen supported on a 250-μm [60-mesh] screen). The filtration area is 3.5 in.² [22.6 cm²]. After 30 min, the collected filtrate volume is noted. The reported fluid-loss value is equal to the collected filtrate volume multiplied by two. If all of the filtrate passes through the screen in less than 30 min, the following equation is used to calculate the API fluid loss.

\[
(q_{API})_{calc} = 2V_t \left( \frac{5.477}{\sqrt{t}} \right) \quad (B-4)
\]

where

\[ V_t = \text{volume of filtrate (mL) collected at time } t \text{ (min)}. \]

The test is performed either in a static heated filter-press cell, shown in Fig. B-9, or in a stirred fluid-loss cell, shown in Fig. B-10. Whatever the equipment—static filter press or stirred fluid loss—the actual filtration test always takes place with a slurry in a static state. Before the filtration test, slurry conditioning may be performed in a pressurized consistometer, in a stirred fluid-loss cell, or, if the temperature is less than 194°F [90°C], in an atmospheric consistometer.
The prescribed test evaluates slurry fluid loss under static conditions (immediately following placement), regardless of whether the slurry is conditioned in a consistometer or in a stirred fluid-loss cell. This procedure makes no provision for the measurement of fluid loss during placement, although results of fluid-loss determinations under dynamic conditions have been reported (Bannister, 1978). As discussed in Chapter 5, the dynamic fluid-loss rate of a given slurry is usually higher than the static fluid-loss rate unless a filtercake has already been deposited by the drilling fluid, a spacer, or a chemical wash.

The stirred fluid-loss test equipment determines the fluid-loss rate without transferring the heated slurry from one vessel to another. This removes the safety hazard of transferring the heated slurry from the consistometer to the heated filter press. Commercially available stirred fluid-loss equipment can operate at up to 400°F [204°C] and 2,000 psi [14 MPa].

Static high-pressure, high-temperature filter presses are available for use at slurry temperatures up to 350°F [177°C] for the smaller units (175 mL), and up to 500°F [260°C] for the larger units (500 mL) (Fig. B-11). All units require the use of a backpressure receiver when the slurry temperature exceeds 200°F [93°C] to prevent evaporation of the filtrate.

B-4.5 Strength

The procedures to determine the strength of set cement are described in API RP 10B. Two types of strength measurements are described:

- **compressive strength** (measured by a destructive crush test)
- **sonic strength** (calculated from sonic-velocity measurements through the set cement).

B-4.5.1 Compressive strength

Test cement slurries are prepared according to the API/ISO mixing procedure, poured into 2-in. cubic molds, and cured for various time periods at specific temperatures and pressures. The set-cement cubes are removed from the molds and placed in a hydraulic press, where increasing uniaxial load is exerted on each until failure. The compressive strength is then calculated by dividing the load at which failure occurred by the cross-sectional area of the specimen.

Figure B-12 shows a typical curing mold that makes two test specimens. API/ISO procedures describe curing at pressures from atmospheric pressure to 3,000 psi [21 MPa]. For atmospheric tests, curing in a water bath or a cooling bath can simulate cold weather or permafrost conditions. Pressurized curing chambers, such as the device shown in Fig. B-13, are available in various sizes and with varying performance capabilities. There are commercial units that hold up to 32 specimens, with maximum operating conditions of 600°F [315°C] and 20,000 psi [140 MPa]. Section 7.7 of API RP 10B contains the prescribed heat-up and pressurization schedules, which, like the thickening-time schedules, are derived from field data and the anticipated wellbore temperature gradient. For arctic cement systems, special curing methods are given in API RP 10B. In addition, a method for evaluating a cement system’s resistance to freeze-and-thaw cycling is given. When a set-cement specimen is placed in the hydraulic press for strength measurement (Fig. B-14), the loading rate is regulated according to the anticipated strength of the specimen. For specimens with a compressive strength greater than or equal to 500 psi [3.5 MPa], the loading rate is 4,000 psi [28 MPa]/min. For specimens with a compressive strength less than 500 psi, the loading rate is 1,000 psi [6.9 MPa]/min.

![Fig. B-11. Filter-press assembly for high-temperature fluid-loss tests (photograph courtesy OFI Testing Equipment, Inc.).](image)
B-4.5.2 Sonic strength

The strength can be estimated ultrasonically (Rao et al., 1982). The ultrasonic cement analyzer (UCA), shown in Fig. B-15, measures the travel time of ultrasonic energy through a cement sample as it cures under simulated temperature and pressure conditions. The ultrasonic measurement is nondestructive and may be made continuously as the cement sample cures at high pressure and elevated temperature. The sonic strength is correlated to the transit time (reciprocal of ultrasonic velocity) using an empirical relationship initially established from mechanical compressive strength and transit time data for various slurry systems. The strength estimate can be output directly via a preprogrammed microprocessor. API RP 10B now includes testing procedures for nondestructive sonic testing of cements with UCAs.

Cobb et al. (2002) developed a method to predict the sonic strength of foamed cements. One first measures the sonic strength of the base slurry. Using a strength-to-foam quality correlation, one then calculates the strength estimate.

The strength values obtained using either the API/ISO crush test or the UCA are indicative of the integrity of the cement under uniaxial loading (i.e., no lateral restraint). In the wellbore, the cement is subject to complex triaxial loading, and the failure stresses may be substantially different from those observed in the standard compressive strength test (Chapter 8). Furthermore, the strength measurement provides no guide to the shear strength of the casing-to-cement or the casing-to-formation bond (Parcevaux and Sault, 1984). More detailed procedures to determine cement mechanical properties are presented in Section B-4.
B-4.6 Free fluid and slurry sedimentation

When a slurry is allowed to stand for a period of time before setting, water may separate from the slurry, migrate upward, and accumulate in pockets or at the top of the column. This separation can impair zonal isolation, particularly in a highly deviated wellbore (Chapter 13). The free-fluid test measures this separation tendency in the laboratory, using a graduated cylinder as a simulated wellbore.

The procedure permits slurry conditioning at elevated temperatures and pressures. No provision is made for fluid loss. The duration of the test is 2 hr, measured from the moment the slurry is poured into the graduated cylinder. For temperatures less than 176°F [80°C], the graduated tube is placed in a preheated or precooled test chamber. For higher temperatures, the graduated tube is placed in a preheated, oil-filled heating chamber that is maintained at a pressure sufficiently high to prevent boiling. The test procedure is documented in

Fig. B-15. UCAs (photos courtesy Chandler Engineering, LLC, Cement Test Equipment, Inc., and Fann Instrument Company).
API RP 10B. To simulate deviated wellbores, many operators orient the graduated cylinder at the angle of wellbore deviation. An increase in free fluid is usually observed in such situations; however, there is no clear understanding of how free fluid depends upon column height.

In addition to free-fluid development, the suspended solids may also tend to separate from the slurry and settle toward the bottom of the cement column. This separation is particularly evident in slurries containing weighting agents. Such sedimentation can produce variations in slurry density, leading to annular invasion and possible loss of well control (Chapter 9).

After an appropriate conditioning period, the slurry is poured into a sedimentation tube (Fig. B-16). The slurry-filled tube is placed in a water bath or autoclave preheated to the anticipated wellbore temperature or 194°F [90°C], whichever is cooler. The slurry temperature is then adjusted to simulate temperature changes in the wellbore. A minimum amount of pressure is applied to prevent slurry boiling, or if desired, the pressure can simulate bottomhole conditions. After an appropriate curing period (typically 24 hr, or until set), the set cement is sliced into several segments or wafers. The density of each segment is measured, and the percent density difference between the liquid sample and the set sample is calculated using the following equation.

\[ \Delta \rho = \left( \frac{\rho_{\text{cem}} - \rho_{\text{slurry}}}{\rho_{\text{slurry}}} \right) \times 100, \]  

(B-5)

where
\[ \rho_{\text{cem}} = \text{density of cement segment} \]
\[ \rho_{\text{slurry}} = \text{density of cement slurry}. \]

The test procedure is presented in API RP 10B.

Fig. B-16. Slurry sedimentation test apparatus for use in an autoclave.

B-4.7 Rheological measurements

A detailed discussion of cement rheological properties and their significance is found in Chapter 4, and a summary of the pertinent mathematical relationships is presented in Appendix A. The use of these relationships for accurate prediction of friction pressure and slurry-flow properties depends upon reliable laboratory measurements of the rheological parameters.

Coaxial cylinder rotational viscometers are the most common apparatuses to make rheological measurements with cement slurries. As shown in Figs. B-17 and B-18, rotational viscometers are designed with a rotating outer cylinder (couette type, covered by API RP 10B) or a rotating inner cylinder (Searl type) (Bannister, 1980).

Fig. B-17. Couette-type rotational viscometer (photographs courtesy Chandler Engineering, LLC, and Fann Instrument Company).
API RP 10B provides detailed guidelines concerning slurry preparation and conditioning before rheological measurements. The shear history that a slurry experiences during mixing can have a significant effect upon the ultimate rheological properties. The slurry is prepared in a blade-type mixer according to the guidelines presented in API Specification 10A (summarized in Section B-4.1).

Immediately after mixing, the slurry is poured into the slurry container of an atmospheric or pressurized consistometer for preconditioning. The container temperature must be initially ambient to avoid thermally shocking temperature-sensitive additives. The slurry is then heated to the test temperature and stirred for a period of 20 min. If preconditioning was performed in a pressurized consistometer at an elevated temperature and pressure, the slurry must be cooled as quickly as possible to 190°F [88°C] before the slurry container is opened.

After preconditioning, the slurry is immediately poured into a preheated couette-viscometer cup to the fill line. With the sleeve rotating at the lowest speed, the cup is raised until the liquid level reaches the inscribed line on the sleeve. This operation minimizes slurry gelation and ensures uniform distribution of the slurry. After the slurry temperature is noted, dial readings are recorded at various rotational speeds. As discussed in Chapter 4, the manner in which the readings are taken is critical. Readings must be taken first in ascending order and then in descending order. As shown in Table B-3, the rheological measurements are reported as an average of the ramp-up and ramp-down readings.

<table>
<thead>
<tr>
<th>Rotational Speed r/s</th>
<th>Ramp-up Reading</th>
<th>Ramp-Down Reading</th>
<th>Reading Ratio</th>
<th>Average Reading</th>
</tr>
</thead>
<tbody>
<tr>
<td>3</td>
<td>21</td>
<td>24</td>
<td>0.87</td>
<td>22.5</td>
</tr>
<tr>
<td>6</td>
<td>40</td>
<td>36</td>
<td>1.11</td>
<td>38</td>
</tr>
<tr>
<td>30</td>
<td>65</td>
<td>83</td>
<td>0.78</td>
<td>74</td>
</tr>
<tr>
<td>60</td>
<td>84</td>
<td>100</td>
<td>0.84</td>
<td>92</td>
</tr>
<tr>
<td>100</td>
<td>100</td>
<td>115</td>
<td>0.87</td>
<td>107.5</td>
</tr>
<tr>
<td>200</td>
<td>137</td>
<td>147</td>
<td>0.93</td>
<td>142</td>
</tr>
<tr>
<td>300</td>
<td>170</td>
<td>170</td>
<td>170</td>
<td></td>
</tr>
</tbody>
</table>

‡ Initial slurry temperature = 150°F [66°C].
§ Final slurry temperature = 146°F [63°C].
†† Rheological properties reported at average temperature of 148°F [65°C].

In addition to friction-pressure and flow-regime calculations, laboratory measurements of rheological parameters can provide information about other slurry characteristics. A decrease in shear-stress values when measured at decreasing shear rates, compared to those measured at increasing shear rates, may indicate that the slurry is thixotropic. A determination of gel strength, using the procedure described in API RP 10B will provide an indication of a slurry gelation tendency. The procedure prescribes a conditioning period of 20 min before measurement of the rheological parameters; however, measurements taken immediately after mixing may provide some indication of slurry mixability, particularly in a batch mixer.

B-4.8 Static gel strength
The static gel strength of a cement slurry is routinely measured immediately after determining the rheological properties of the slurry. A couette-type rotational viscometer is used for the measurement. Typically, the gel strength is measured after the slurry has been left undisturbed for 10 sec and again after resting for 10 min (API RP 10B).
Procedures specifically developed for measuring the static gel strength of a cement slurry use a consistometer-type apparatus equipped with a low-friction magnetic drive and torque-measuring system coupled to the paddle (Sabins et al., 1980). The slow movement of the paddle apparently does not inhibit gel strength development, yet it permits torque measurements.

It is important to note that rheometers are not appropriate for determining the transition time of a slurry (Chapter 9).

New measurement techniques that rely on the analysis of the acoustic waveform transmitted through the cement have been developed (Fig. B-19). They allow the evaluation of static gel strength under downhole conditions (pressure and temperature). Proprietary algorithms are used to transform the acoustic waveform transmitted through the cement into an evaluation of static gel strength.

The static gel strength is an important variable related to annular fluid migration. Additional information about static gel strength testing in the context of annular fluid migration is presented in Chapter 9.

B-4.9 Expansion and shrinkage
Set-cement expansion can be measured using the procedure described in ASTM Standard C151, *Standard Test Method for Autoclave Expansion of Portland Cement*. This procedure, developed for the concrete industry, involves placing the cement slurry into a bar-type mold and curing it underwater at atmospheric pressure. The cement bar is removed from the mold when it is sufficiently strong, the length is carefully measured, and the bar is then returned to the water bath for further curing. Periodically during the curing period, the bar is removed for additional length measurements. The ASTM method has two major drawbacks: (1) because the cement must develop some strength before a length is measured, it is impossible to obtain a reliable “zero reading,” and (2) there is no provision for studying the effect of pressure.

In 1994, the API formed a work group on cement shrinkage and expansion. API Technical Report 10TR2 (1st ed.), July 1997, “Shrinkage and Expansion in Oilwell Cements,” proposed equipment and procedures to investigate shrinkage and expansion in oilwell cements. The report described four pieces of equipment to measure cement-volume changes under different boundary conditions: the annular ring expansion mold, the cylindrical sleeve, the membrane test, and the cement hydration analyzer (CHA).

The annular expansion ring test measures linear expansion under conditions of free access to water. Free access to water is defined as an open system. The annular expansion mold (Fig B-20) simulates the annulus of a well. The cement slurry is poured into the annular space in the mold, and the mold is placed into a water bath or pressurized curing vessel. Because the slurry is in contact with water during the entire test, water entry...
will compensate for internal shrinkage as long as the cement matrix is permeable. The outer ring has a vertical slit; therefore, if the cement expands during the hydration period, the diameter of the ring will increase. Conversely, if the cement shrinks, the diameter of the ring will decrease. The change in ring diameter is determined by measuring the distance between the two pins mounted on the outside of the mold with a micrometer. Measurements are taken before and after curing, and special care is required to ensure that both measurements are taken at the same temperature.

The percent dimensional change (shrinkage or expansion) is calculated as follows:

\[ \Delta V = 0.358 \left( L_f - L_i \right), \]  

where

- \( L_i \) = initial distance measurement between pins (mm)
- \( L_f \) = final distance measurement between pins (mm)
- \( \Delta V \) = dimensional change of the cement sample (%).

This method is described in ISO 10426-5, *Test methods for determination of shrinkage and expansion of well cement formulations at atmospheric pressure*.

The cylindrical sleeve test is also an open-system bulk-expansion measurement with free access to water. The sleeve, invented by Spangle (1983), consists of a cylindrical mold with a vertical slit. The sleeve is designed to fit inside a standard 2-in. cube mold (Section B-4.4). As shown in Fig. B-21, three sets of pins are mounted on the outside of the sleeve, each located on opposite sides of the slit and secured with a spring. The sleeve is closed when the slurry is first introduced, and a zero reading of the distance between the three sets of pins is taken with a micrometer. If the set cement expands during the curing period, the diameter of the sleeve increases and the longitudinal slit opens. After the mold is removed from the curing chamber, the distances between the pins are measured again, and the amount of expansion is calculated according to the following equation.

\[ \Delta V = \left[ \frac{r_{i+L}}{r_i} \left( \frac{L_2}{L_1} - 1 \right) \right], \]  

where

- \( L_1 \) = average distance between the pins when the sleeve is empty
- \( L_2 \) = average distance between the pins when the sleeve is expanded
- \( r_i \) = inside radius of sleeve
- \( r_i + L \) = plus the length of the pin.

The membrane test is a measurement of bulk shrinkage or bulk expansion under impermeable conditions. Lack of free access to water is defined as a closed system. The slurry is poured into an impermeable flexible membrane (i.e., a latex sheath) that is sealed by tying a knot at the top. The membrane is attached to a balance hook and immersed into a temperature-controlled water bath. The slurry temperature is measured with a thermocouple immersed in the slurry. The “pseudoweight,” as measured by the balance, is the weight of the membrane containing cement minus the buoyancy force acting on it. An increase of the pseudoweight corresponds to a decrease of the volume (shrinkage).

The CHA test (Fig. B-22) measures inner shrinkage under free access to gas. The slurry is placed in a closed cell equipped with a gas inlet. During the test, a constant gas pressure is applied to the container. Shrinkage is determined by measuring the volume of gas required to maintain a constant pressure inside the test cell until the cement hardens. Assuming that the cement matrix remains sufficiently permeable to gas throughout the test, this volume of gas corresponds to the inner shrinkage of the cement. This test can also be performed using water instead of gas. If gas is used, this method is essentially a closed test. If water is used, this method is an open test.

More recently, Bosma et al. (2000) developed an apparatus with two cells to measure expansion and shrinkage phenomena in either a closed or open system, as defined by API 10TR2. Concurrently, the apparatus can measure the hydration and setting behavior of the cement system, and information about the mechanical properties of the set cement can be acquired. In addition, the apparatus is capable of operating at elevated temperatures and pressures.
B-4.10 Gas migration

At this writing, neither API nor ISO have published a standard method or procedure for testing gas migration control in cement slurries; therefore, there is no recognized standard laboratory procedure to characterize the ability of a cement system to prevent or reduce gas migration.

A significant number of nonstandard laboratory tests for gas migration has been developed by the industry throughout the years. A wide variety of experimental prototypes that attempt to simulate the gas migration process are described in the literature. Two main types of experimental simulators exist: large-scale pilot devices, which attempt to reproduce the process as it occurs in the wellbore, and small-scale, benchtop models, which can be used to derive the fundamental laws of a particular physical process under investigation. To date, none of the simulators described in the literature permits the derivation of a physical model that quantitatively describes gas migration over a wide range of conditions. Recently, many investigators have begun to rely upon measuring individual slurry properties such as gel strength development and shrinkage. The results of these data are then used either as input into mathematical simulators or for comparing the performance differences between various slurries.

A thorough discussion of the various devices for gas-migration testing, complete with schematic diagrams and photographs, is presented in Chapter 9.

B-4.11 Permeability

The permeability of the cement sheath strongly affects zonal isolation. An operational procedure for determining the relative permeability of set cement to liquid or gas is contained in API RP 10B. The procedure determines comparative permeabilities of cement samples rather than absolute permeability values. Fluid is injected through the sample at either a constant flow rate or constant differential pressure, and the resulting fluid-flow rate is measured.

A variety of permeameters is available to perform this test. Earlier apparatuses and procedures were developed in the early 1950s (Morgan and Dumbauld, 1952). Today, many laboratories use a Hassler sleeve-type holder (Figs. B-23 and B-24), and measurement of permeability to air, methane, or other gases is fairly routine (API, 1960).
Water permeability is usually determined by forcing water through a core of set cement at a differential pressure of 20 to 200 psi [100 to 1,400 kPa]. The water expelled from the core is collected during a 15-min time period, or until 1 mL has been accumulated in the measuring tube. Darcy’s law (Eq. B-8) is used to calculate the permeability.

\[ k = \frac{q \times \mu_{\text{water}} \times L}{A \times \Delta p}, \]  

(B-8)

where

- \( A \) = sample cross-sectional area (cm²)
- \( k \) = permeability (mD)
- \( L \) = sample length (cm)
- \( \Delta p \) = differential pressure (psi)
- \( q \) = flow rate (mL/s)
- \( \mu_{\text{water}} \) = water viscosity (cp).

To measure gas permeability, the core sample must be dried completely before testing. The API and ISO do not specify the drying procedure. Sample drying can be performed by placing the sample over a desiccant or by drying it in a vacuum oven or in a conventional oven at high temperature (Mindess and Young, 1981). This stage may prove to be crucial, because the sample can be damaged by the drying process, leading to questionable results. Regardless of the method chosen, care must be taken to preserve sample quality and assure the sample is dry before testing.

The gas permeability of the set cement is calculated using Darcy’s law according to the following equation (B-9).

\[ k = \frac{2000 \times \mu_{\text{gas}} \times q_{\text{gas}} \times p \times L}{A \times \left[ (p_{\text{inlet}})^2 - (p_{\text{outlet}})^2 \right]}, \]  

(B-9)

where

- \( A \) = sample cross-sectional area (cm²)
- \( k \) = permeability to gas (mD)
- \( L \) = sample length (cm)
- \( p \) = adjusted barometric pressure (atm)
- \( p_{\text{inlet}} \) = inlet pressure (atm)
- \( p_{\text{outlet}} \) = outlet pressure (atm)
- \( q_{\text{gas}} \) = flow rate of gas (mL/s)
- \( \mu_{\text{gas}} \) = viscosity of gas (cp).

B-5 Spacers and chemical washes

As discussed in Chapter 5, spacers and chemical washes perform two important functions during a cementing operation: to clean and remove the drilling fluid from the wellbore and to minimize cement contamination by the drilling fluid. To accomplish these objectives, the spacer and wash must impart some degree of cleaning effect in the wellbore and must be compatible with both the drilling fluid being displaced and the cement slurry being placed in the hole. Laboratory testing of these materials must include procedures to evaluate the compatibility and the cleaning effect.

B-5.1 Compatibility

Operational procedures to evaluate compatibility are contained in API RP 10B, Section 16. The procedures test the effects of a spacer or chemical wash on the behavior of both the drilling fluid and cement slurry. Various volumetric ratios of drilling fluid, cement slurry, and spacer are specified. The thickening time, fluid-loss rate, and rheological characteristics of each mixture are measured. No specific criteria are provided to aid in the interpretation of the test results.

B-5.2 Cleaning effect

There are no standard procedures to evaluate the mud-removal capability of preflushes. Following the description presented in Chapter 5, the cleaning process is
achieved in two steps: bulk displacement of the mud followed by cleaning of the annulus wall. Bulk displacement is governed by fluid mechanics and the rheology and density of the spacer or chemical wash. These properties can be measured under simulated downhole conditions using the standard API and ISO procedures if the temperature does not exceed 185°F [85°C]. However, it is often necessary to extrapolate laboratory data to downhole temperature and pressure conditions using appropriate models.

No standard method has been agreed upon to evaluate the annular wall cleaning efficiency of spacers and washes. As discussed in Chapter 5, the relevant phenomena include the following.

1. When the mud is an invert emulsion, the wash or spacer must invert it to an oil-in-water emulsion (Fig. B-25).
2. The oil film adsorbed on the wall is displaced to leave water-wet surfaces.
3. The mud layer on the walls is eroded by the tangential flow.

Phenomena 1 and 2 are specific to invert-emulsion muds, while tangential erosion is applicable to all mud types.

As an aqueous spacer displaces a water-in-oil emulsion mud, both fluids come into contact in the wellbore. Throughout the intermixing zone, the emulsion will absorb water until the water droplets become so large that the external oil layer can no longer contain them. At this point, the emulsion breaks and the electrical conductivity of the mixture increases (Fig B-26).

Heathman et al. (1999 and 2000) developed an apparatus and test procedure aimed at comparing the ability of different fluids to convert the mud to an oil-in-water emulsion. As shown in Fig. B-27, the wettability apparatus is comprised of (1) a double-walled, stainless-steel mixing jar with electrodes mounted inside the walls, (2) a control box containing the temperature controller and the wettability electronics, and (3) a harness connection that provides power to the heater, the thermocouple, and the electrodes. The apparatus allows operators to test drilling fluid spacer mixtures at controlled shear rates and controlled temperatures up to 190°F [88°C].

The interpretation of the results is straightforward, provided the operator keeps certain points in mind.

- Once the mud is inverted, an oil film may remain on the electrodes, providing incorrect measurements.
- Even if operated at low rotary speed, the blade mixer provides a high shear rate that helps disperse and stabilize emulsions.
- The apparatus does not provide a reliable measurement of the wettability of the annular wall, because the electrode is made from a material that is different from the casing and the formation rock.
Various means to monitor the tangential erosion of a mud layer from a solid surface have been proposed.

- Boyington et al. (1989) described the use of a piece of tile, representing the formation rock, first immersed in the mud and then rotated in the cleaning fluid. A sample of steel pipe, preferably the same metal as the casing, can be used instead of the tile to evaluate casing cleaning effectiveness.

- Davison et al. (2001) used a rotational viscometer that was covered with sand to simulate the formation wall.

- A variation of the Davison et al. (2001) method involves covering the rheometer rotor with a piece of metallic mesh to simulate the casing.

In these methods, the mass of removed mud is monitored versus time. The test results strongly depend on the nature of the solid surface. Therefore, for comparison of different fluid systems, the solid surface must be very reproducible from test to test.

Al Khayyat et al. (1999) proposed monitoring the water-wettability of a steel pipe covered with mud while cleaning it by rotation in the spacer. The wettability is visually estimated by observing water drops poured on the cleansed metal surface. Ali et al. (1997) described a procedure in which a volume of mud and a volume of brine are shaken in a glass jar. The water wettability is determined visually by observing how brine droplets behave on the glass surface.

The above methods allow the screening of various cleaning solutions. The main limitations of these methods include the need to use various complementary methods to mimic downhole phenomena. Also, because the tests are performed at atmospheric pressure, the test temperatures are limited to 185°F [85°C].

**B-6 Mechanical properties testing of well cements**

**B-6.1 Introduction**

In a wellbore, the cement sheath supports the casing and seals the annulus between the casing and the formation or between two casing strings. During the lifetime of the well, the cement will be exposed to stresses induced by temperature and pressure changes, e.g., through steam injection, fracture stimulation, or depletion (Chapter 8). Uniaxial compressive strength and permeability to gas or water are the principal tests performed on set cement. These tests do not provide sufficient information to predict and model the behavior of the cement sheath under the expected well stress conditions.

Analytical and numerical models help predict the stress distribution in the cement sheath caused by changes in downhole conditions. Whatever the calculation method, the mechanical and thermal properties for all the involved materials—steel casing, cement, and formation—are required. The results can differ significantly depending on the testing method used to determine these properties.

To provide coherent, reproducible, and comparable results, one must define and adhere to consistent test procedures. To become familiar with mechanical properties terminology and concepts in the procedures described below, a review of Chapter 8 is recommended.

It is important to point out that the test methods assume that the cement specimens are continuous materials exhibiting a linear elastic mechanical behavior. As discussed in Chapter 8, cement systems are rather porous materials. Nevertheless, experiments described by Boukhelifa et al. (2004) showed that the continuous and linear elastic assumption was sufficient for predicting the failure mode.

**B-6.2 Sample preparation**

The cement samples must be prepared with care to ensure that their properties are representative of those that will exist in the well. The initial slurry must be stable with, if possible, zero free water and no sedimentation.

The cement system must be cured at bottomhole static temperature (BHST) for a period sufficient to allow the set cement to reach a stable compressive strength. Curing time of 7 to 28 days may be required. For thermal cements, the samples must be cured until the appropriate cement-phase conversions have occurred (Chapter 10). For systems that will be used in steam injection wells, it is appropriate to first cure the cement slurry at the BHST and then expose the set cement to steam-injection temperatures.

To eliminate the effects of entrained air, all systems should be cured in a pressurized curing chamber. If pressurized curing chambers are not available, the cement slurry should be thoroughly degassed by stirring it gently under a vacuum.

The cement systems should be cured in molds of, or machined into, the appropriate geometry. During all operations, the samples must remain saturated with water to avoid drying shrinkage that may induce fractures within the specimen.
B-6.3 Cement static mechanical properties

Chapter 8 discusses some key measurements to determine whether a cement sheath can withstand the expected temperature and pressure changes downhole. These key cement properties—tensile strength, compressive strength, Young's modulus, and Poisson's ratio—are derived from stress-strain tests performed on the solid material.

Stress is a force per unit area and is expressed in the same units as pressure. When submitted to a stress field, a material deforms. The rupture strengths of a material in compression and in tension are the compressive strength and the tensile strength. Strain is the relative change in shape or size of a material caused by externally applied forces. This is a displacement per unit length and is a dimensionless value. These properties are crucial, because the best sealants will be those that can withstand the most extreme deformations and highest stresses. Hence, the optimal sealing materials would feature low Young's moduli and high compressive and tensile strengths.

Assuming perfect linear elastic mechanical behavior, the elastic constants are intrinsic values for homogeneous materials. However, when stressed in flexion, compression, or tension, the elastic constants can vary depending upon the stress distribution and loading rate. This is particularly true for cements because of the heterogeneity of their grains and pores.

The elastic constants should be measured according to the way the cement sheath will be stressed. When cement is in tension, a flexural test is the most appropriate way to measure the Young's modulus. If cement is under compression, a compressive test is appropriate. However, the Young's modulus determined in a compressive test is commonly higher than the value measured in a flexural test. Therefore, to be conservative, one can use the value obtained in a compressive test for any stress condition. Because test results may vary depending upon the test procedure used, a consistent method should be followed when evaluating a series of cement systems.

B-6.3.1 Uniaxial unconfined compression test

The methods discussed below are more sophisticated than the uniaxial compressive strength test described in Section B-4.4. When an axial load is applied on an unconfined cement sample, there are no constraints in the lateral direction. The stress distribution varies depending on the geometry and size of the specimen, because friction is generated at the interfaces between the sample and platens of the press. The optimal sample height-to-width ratio is between 2 and 3 (Vutukuri et al., 1974).

To reduce frictional effects at the interfaces, the recommended sample geometry for a uniaxial compression test is a cylinder that is 1 in. [25.4 mm] in diameter and 2 in. [50.8 mm] long.

A standard mechanical measurement apparatus imposes a load or a deformation at a fixed rate and magnitude (Fig. B-28). This allows the measurement of the unconfined compressive strength, Young's modulus, and Poisson's ratio.

During compression, the material will shorten in the loaded direction (negative strains) and expand in the normal or unconfined direction (positive strains). Load, axial displacement, and radial displacement are monitored throughout the test. Axial deformation is typically measured with a linear variable differential transformer (LVDT) set on the moveable platen. Radial displacement can be measured with strain gauges or a cantilever set halfway up the cylindrical sample (Figs. B-29 and B-30).

Cement is a porous medium saturated with a fluid. Therefore, the loading rate is an important test parameter. As discussed in Chapter 8, drained and undrained compressive strengths can be measured on set cement. A drained condition occurs when there is no change in
pore pressure caused by external loading. Hence, the pore fluid can drain out of the sample. An undrained condition occurs when the pore fluid cannot drain out of the cement matrix because of a high loading rate. In this case, the load is shared between the pore fluid and the cement matrix. The rate of deformation should be low enough to enable unimpeded drainage. ASTM C469-02, *Static Modulus of Elasticity and Poisson’s Ratio of Concrete in Compression*, presents a procedure for determining the elastic constants of concrete in compression and recommendations for the load rate and the cycling procedure. The procedure suggests the application of several load-unload cycles on the sample, remaining in the elastic domain (40–50% of the uniaxial compressive strength). Also, to ensure testing close to drained conditions and for practical reasons (duration of the test), the recommended axial deformation rate is 0.05 mm/min.

The first loading-and-unloading cycle generates more deformation than subsequent cycles that follow the same path. This is because of experimental artifacts when the sample surface comes in contact with the loading platen of the machine (misalignment), added to strengthening of the material after compaction (plastic deformation). As shown in Fig. B-31, the static Young’s modulus measured from the initial loading cycle ($E_1$) is lower than the value measured at the second loading cycle ($E_2$). Consequently, data from a simple crush test give an optimistic estimate of Young’s modulus. Subsequent loading cycles provide values very similar to $E_2$; therefore, $E_2$ is a more representative value and should be used for modeling. At least two subsequent cycles are recommended to verify the repeatability of the result.

Before testing, it is advised to measure and report the set-cement density and the specimen geometry (diameter and height). The faces of the specimen must be parallel to the platens because ridges and hollows at the specimen ends may concentrate stresses and cause failure at a relatively low load. The use of a specific grinding machine or a precision diamond saw may be required to ensure parallelism of the end faces. A minimum of three specimens per cement design is recommended.

As shown in Fig. B-31, Young’s modulus is the slope in the linear domain of the curve of axial stress versus axial strain. The Poisson’s ratio is the slope in the linear domain of the radial strain versus axial strain (Fig. B-32). The linear domain is characterized by reversible deformations.

The following test method can be used at ambient temperature to simultaneously determine the Young’s modulus, Poisson’s ratio, and uniaxial compressive strength. The method requires at least four cylindrical specimens (1 in. [25.4 mm] diameter; 2 in. [50.8 mm] length).

1. Perform a uniaxial compression test to failure on the first sample at a constant deformation rate (e.g., 0.05 mm/min). This gives a rough value of the uniaxial compressive strength (UCS).

2. Place axial and radial displacement sensors on the second specimen.
Fig. B-31. Radial and axial strains while cycling a compressive stress on a test cement up to half its compressive strength (ASTM Method C469). $E_1$ and $E_2$ are respectively the Young’s Modulus of the first and subsequent loadings.

Fig. B-32. Radial strains as a function of axial strains while cycling a compressive stress on a cement sample. $\nu$ is the Poisson’s ratio.
3. Load this specimen to 50% UCS, and then unload to a very low stress (e.g., 30 psi [0.2 MPa]). The test can be recorded as a quality-control check, but the data will not be used in the analysis.

4. Repeat the load-unload cycle in Step 3 two more times. Record the stress and the axial and radial strains simultaneously. Use the loading-up portions of the curve to determine the Young’s modulus and Poisson’s ratio.

5. Repeat steps 2–4 with the other specimens. Deformations are reversible in the elastic domain, so this test should be nondestructive.

6. Perform a uniaxial compression test to failure with the three undamaged specimens to determine the UCS.

7. Report the mean values of the UCS and the elastic constants.

**B-6.3.2 Confined triaxial compression test**

During a confined triaxial compression test, a cylindrical core is placed in a cell and subjected to constant confining pressure. The pressure is hydraulic and is applied radially through a thin impermeable membrane. Platen apply an axial load vertically until the sample fails. The Hoek cell is an appropriate triaxial cell (Fig. B-33) for investigating rocks and set cements. A special cantilever that fits inside the pressure cell measures the radial deformation of the sample. As in the uniaxial compression test, displacement transducers located outside the pressure cell measure the axial displacement. The end platens of the cell have a connection to an independent pump that allows control of the cement pore pressure during the test (i.e., a drained condition). If the system were completely sealed, the pore pressure would build up during the measurement (i.e., an undrained condition), leading to an incorrect determination of the cement properties. If triaxial testing is performed at several confining pressures, the angle of internal friction can be determined (Chapter 8).

**B-6.3.3 Brazilian test**

The uniaxial tensile strength is the stress value of failure when the cement sample is subjected to tension (i.e., when its ends are pulled). The most common way to measure tensile strength is to anchor a cylindrical core at both ends and stretch it to failure. However, this test is difficult with set cement because the core frequently breaks at the grip points. Therefore, an indirect method known as the Brazilian test (Carneiro and Barcellos, 1953) is often performed to determine uniaxial tensile strength with set cement.

The technique involves loading disk-shaped specimens in compression across their diameter until they fail (Fig. B-34). A tensile stress is generated at the center of the disk in a direction normal to the applied load. The use of curved platens, as described by the International Society for Rock Mechanics (ISRM) Commission on Standardization of Laboratory and Field Tests, *Suggested Methods for Determining Tensile Strength of Rock Materials* (1978), is preferred to improve the stress distribution in the sample. ASTM International (formerly the American Society for Testing and Materials) also standardized this test for determining the tensile strength of concrete—as described in ASTM C496, *Standard Test Method for Splitting Tensile Strength of Cylindrical Concrete Specimens*.

![Fig. B-33. Hoek cell for triaxial compression test.](image)

![Fig. B-34. Cement sample at the end of the Brazilian test.](image)
However, for routine tests, simpler methods that do not require curved platens can be performed on 2-in. [50.8 mm]-diameter and 1-in. [25.4 mm]-thick disk-shaped cement specimens, with at least three specimens per design. For testing brittle rocks, Wang and Xing (1999) suggested flattening the two edges of a disk-shaped specimen in contact with the press platens and defined the required widths of the flat ends. Another test procedure involves covering the steel platens of the press with cardboard pads to lower the compressive stresses at the contact points between specimen and platens. The pad's width should not exceed one-tenth of the cylinder diameter (Pittet and Lemaître, 2000).

Once a test method is selected, it must remain the same throughout a given study or for comparison purposes. For all testing methods, Equation B-10 is used to calculate the tensile strength. Either U.S. or SI units may be used, so long as the choice is consistent.

\[
S_{\text{tens}} = \frac{F_{\text{fail}}}{2\pi \times d_{\text{disk}} \times h_{\text{disk}}}, \quad \text{(B-10)}
\]

where

- \(d_{\text{disk}}\) = disk diameter
- \(h_{\text{disk}}\) = disk thickness
- \(F_{\text{fail}}\) = load at failure
- \(S_{\text{tens}}\) = tensile strength.

The test is valid when the primary fracture starts from the center of the disk and spreads along the loading diameter. If not, the sample did not fail under tension and the test must be discarded.

### B-6.4 Dynamic mechanical properties

#### B-6.4.1 Dynamic compressive strength

The UCA is an instrument used to monitor the strength development of cements (Section B-4.4) at simulated downhole pressure and temperature. The strength is indirectly estimated by monitoring the compressional velocity of ultrasonic waves transmitted through the cement specimen as it hardens. The strength is calculated using proprietary empirical algorithms based on the sound-wave velocity changes for a given slurry density.

It is important to note that the dynamic strength measured by the UCA can differ significantly from the static UCS (Section B-4.4). The static compression test is a direct measurement of the uniaxial compressive strength; therefore, it should be used when entering data into software modeling tools.

#### B-6.4.2 Dynamic elastic constants

Young's modulus and Poisson's ratio can also be determined by ultrasonic methods such as logging tools. The literature shows that the values obtained from static laboratory testing are significantly lower than the dynamic values measured with logging tools (Vutukuri et al., 1974). Dynamic Young's modulus and Poisson's ratio values are calculated from the relationship between the sample density, \(\rho\), and the velocities of compressional \((P)\) and shear \((S)\) waves traveling along the loading axis. The compressional and shear velocities \((v_P\) and \(v_S)\) are linked to the Young's modulus, \(E\), and Poisson's ratio, \(\nu\), by the relationships shown in Eqs. B-11 and B-12.

\[
\begin{align*}
  v_P &= \left[ \frac{E(1-\nu)}{\rho(1+\nu)(1-2\nu)} \right]^{\frac{1}{2}} \quad \text{(B-11)} \\
  v_S &= \left[ \frac{E}{2\rho(1+\nu)} \right]^{\frac{1}{2}} \quad \text{(B-12)}
\end{align*}
\]

For homogeneous elastic materials such as steel, the elastic properties are independent of the stress and wave frequency. The elastic properties are unchanged whether the measurements are dynamic or static.

Plona and Cook (1995) showed that the elastic properties of rocks are stress (or strain) dependent as well as rate dependent. The higher the deformation rate, the higher the elastic modulus and strength will be. This must be taken into account to determine whether absolute dynamic properties can be used directly in numerical models.

The elastic properties of set cements are strain-dependent. Figure B-35 compares the dynamic versus static Young's moduli of four cement systems. Samples were prepared, cured, and tested under the same conditions. Dynamic and static measurements were performed simultaneously. The solid line shows the theoretical perfect match between static and dynamic values. Note also that dynamic properties are undrained properties if the material is saturated.

Two examples of laboratory-scale acoustic tools for examining cements are discussed below.

- The portable ultrasonic nondestructive digital indicating tester (PUNDIT), shown in Fig. B-36, measures the compressional velocity of an ultrasonic pulse through a material. The pulse velocity can be used to assess the quality and uniformity of a material. The method is also useful for detecting the presence of cracks.
Equipment that measures cement dynamic mechanical properties under downhole conditions of temperature and pore pressure (dynamic Young's modulus and dynamic Poisson's ratio) is presently available (Fig. B-37). The equipment is similar to a UCA, except the cell is horizontal to minimize the effects of free water and sedimentation and the equipment measures both the compressional and the shear-wave velocities. The elastic constants are determined from the velocities and the slurry density using Eqs. B-11 and B-12. However, this equipment cannot address the effect of confining pressure.

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**B-6.5 Thermal properties of set cement**

Changes of wellbore temperature caused by production, cool-down from acid or stimulation treatments, or gas or steam injection can deform the cement and generate stress. If stresses are greater than the cement strength, fissures can develop, compromising the integrity of the cement sheath. Ultimately, zonal isolation can be lost.

Thermoelasticity theory provides a linear relationship between the strains, stresses, and temperature variation, assuming that the cement is homogeneous and isotropic. If we consider a radial geometry, the temperature distribution as a function of time is obtained from the heat diffusion equation, which is expressed with the conditions that the initial and boundary conditions only depend on the radius \( r \) as

\[
\frac{\partial^2 T}{\partial r^2} + \frac{1}{r} \frac{\partial T}{\partial r} = \frac{\rho C}{\lambda} \frac{\partial T}{\partial t},
\]

where

- \( \lambda \) = thermal conductivity
- \( \rho \) = density
- \( C \) = specific heat capacity
- \( T \) = temperature.

Owing to thermal expansion, the temperature influences the stress state of the various materials. Linear thermal strain, \( \varepsilon_T \), is directly proportional to the temperature variation \( \Delta T \) (Eq. B-14).

\[
\varepsilon_T = \alpha \times \Delta T,
\]

---
where
\[ \alpha = \text{coefficient of linear thermal expansion}. \]

Test methods are proposed below for the determination of cement thermal conductivity and coefficient of thermal expansion.

**B-6.5.1 Thermal conductivity**

A procedure for the measurement of cement thermal conductivity can be defined following the standard test method ASTM D2326-70, *Method of Test for Thermal Conductivity of Cellular Plastics by Means of a Probe*. A thermal shock probe system is placed between two flat faces of a sample of set cement. The specimen size must be large enough to cover the probe's surface and reduce the boundary effects. Once thermal stability is reached, a thermal pulse is generated to disturb the equilibrium. Induced temperature changes are recorded as a function of time. The linear thermal conductivity of the cement is deduced from this relationship. To establish reproducibility, this test should be performed on a minimum of three specimens.

The greater the value of thermal conductivity, the faster the temperature will equilibrate in the cement sheath. Also, the cement will expand or contract more quickly. Standard lab equipment automates the testing process and provides a direct readout of the thermal conductivity (Fig. B-38).

**B-6.5.2 Coefficient of linear thermal expansion**

According to Eq. B-14, the coefficient of thermal expansion is a strain per unit rise in temperature. A simple technique to determine this coefficient is mechanical dilatometry. A typical apparatus (Fig. B-39) consists of a quartz rod and a digital micrometer positioned on a stand made of a thick stainless steel plate.

The stand sits inside a water bath. The measuring tip of the digital indicator, extended with a thin quartz rod, is in contact with the top of the cement sample bar. The temperature of the water bath is increased to a value lower than the cement curing temperature in several steps. Temperature and sample deformation are recorded throughout the test. The linear coefficient of thermal expansion is calculated from the relative sample dilatation and the temperature increase.

**B-7 Cement characterization and analysis**

Characterization of cement and cementing materials in the laboratory requires appropriate analytical techniques to provide a chemical and physical description of the sample as a whole or of the chemical constituents of the sample. This physico-chemical identification may include the following:

- qualitative determination of the chemical species present
- quantitative measurement of the amount of one or more of these species
determination of physical properties of one or more of these species or of the sample as a whole.

Five types of samples are typically examined in a cementing laboratory: neat cement powder, additives, dry-blended cement with additives, set cement, and mix water. If a failure to obtain set cement in the wellbore is suspected, a sample of fluid returned from the wellbore may be examined to determine the presence or absence of cementitious material.

A wide variety of analytical techniques is available to characterize cement and cementing materials in the laboratory. Obtaining an accurate analysis of a sample may require the use of several of these techniques. An excellent review of techniques for the chemical characterization of neat and dry-blended cements was published by Simpson (1988). Many techniques applicable to the physical characterization of these materials are contained in the ASTM standards. A general description of the most common applications for these techniques is provided here, organized by sample type and by characterization classification.

B-7.1 Chemical characterization of Portland cement

Chemical analysis of Portland cement powder ascertains the relative amounts of the four principal phases (tricalcium silicate, dicalcium silicate, tricalcium aluminate, and tetracalcium aluminoferrite), gypsum, and certain minor oxides (Chapter 2). X-ray diffraction (XRD) determines the crystalline phases qualitatively, although reliable quantitative analyses are possible with careful attention to sample preparation and the use of consistent standards (Aldridge, 1982; Lawrence, 2001). A more accurate quantitative analysis of the principal cement phases requires first performing a complete chemical analysis, using wet chemical methods or atomic excitation methods such as atomic absorption spectrometry (AAS), inductively coupled plasma spectroscopy (ICP), and X-ray fluorescence (XRF). The oxide composition of the cement is calculated, and finally the “potential phase composition” is calculated using equations developed by Bogue (1929) and later refined by Taylor (1989). Bogue’s method is based upon various equilibrium relationships between the clinker phases (Chapter 2).

Selective chemical extraction and complexometric techniques facilitate the separation and subsequent determination of individual phases (Simpson, 1988). Some of these techniques can be applied specifically to determine the reactive phases located on the surface of the cement particle.

Specific identification of surface phases can also be performed using scanning electron microscopy and light microscopy. As with XRD, accurate quantitative analysis requires considerable operator skill. Thermal methods such as thermogravimetric analysis (TGA) and differential thermal analysis (DTA) can be used to determine gypsum, hemihydrate, and free lime in neat cement (Glasser, 2001).

B-7.2 Physical characterization of neat cement and cementing materials

Physical characterization of neat cement powder in the laboratory usually includes measurement of the particle-size distribution, surface area, and specific gravity. The determination of specific surface area is frequently performed using a Blaine permeameter (see ASTM C204, Standard Test Method for Fineness of Hydraulic Cement by Air Permeability Apparatus), shown in Fig. B-40. This method is based on the principle of resistance to air flow through a bed of cement. The time, $t$, required to pass a fixed volume of air through a bed of cement (12.7 mm diameter and 15 mm depth) is related to the specific surface of cement by a simple relationship:

$$A = K \sqrt{t},$$  \hspace{1cm} (B-15)

where $K$ is a constant for the apparatus. The pressure steadily decreases as air flows through the specimen. A reference cement with standardized specific area, produced by the National Institute of Standards and Technology in Washington, D.C., USA, is used to calibrate the apparatus. The accuracy of this method is highly dependent on operator skill.

![Fig. B-40. Blaine permeameter.](image)
Another technique for determining the specific surface area is the Wagner method, described in ASTM C115, *Standard Test Method for Fineness of Portland Cement by the Turbidimeter*. The cement powder is dispersed in kerosene and a column of the suspension is allowed to settle in a turbidimeter. The intensity of light transmitted through the column is recorded as a function of time and depth below the surface of the column. The Wagner method assumes that the cement particles are spherical, and all particles with a diameter of less than 7.5 µm are assumed to have an average diameter of 3.8 µm. As a result, this method gives a lower specific surface than the Blaine method. Values of fineness determined by the Wagner method are included in the specifications for some classes of API/ISO cements (Chapter 2).

A measurement of specific surface area that is independent of particle shape can be obtained using a gas adsorption technique, the Brunauer-Emmett-Teller (BET) method (1938). The instrumentation for this measurement is considerably more sophisticated and expensive than a Blaine permeameter or a Wagner turbidimeter, so BET surface area measurements are not obtained routinely in the field laboratory.

The above surface-area measurements provide a determination of average particle size and surface area within a sample, but they provide no information about the range of particle sizes within that sample. Using more sophisticated instrumentation based on a light-scattering principle, a particle-size distribution can be determined over a wide range of particle sizes, typically from 0.1 to 200 µm (Wertheimer and Wilcock, 1976; Allen, 1981). Such a device is presented in Fig. B-41. These distribution profiles are much more useful in explaining and predicting performance variations between cement samples than simple surface area measurements. A typical particle-size distribution curve for Class G cement is shown in Fig. B-42.
The specific gravity of neat cement powder may vary from 3.10 to 3.25. This variability could result in slurry-density deviations up to 0.27 lbm/gal [33 kg/m³] for slurries with a constant water-to-solids ratio.

The standard method for determining the specific gravity of these materials in the laboratory uses the Le Châtelier flask (ASTM C188, Standard Test Method for Density of Hydraulic Cement). The procedure is simple in concept, but considerable skill and time are required for accurate results. A pycnometer can also be used (ASTM C128, Standard Test Method for Density, Relative Density (Specific Gravity), and Absorption of Fine Aggregate). The procedure can be performed quickly and with accuracy comparable to using the Le Châtelier flask. New devices such as the helium pycnometer (Fig. B-43) can provide rapid and fully automatic density determination on a wide variety of materials including powders, objects, and slurries. Such devices are now the preferred testing apparatuses in the laboratory for density determination.

**B-7.3 Analysis of dry-blended cements**

Chemical analysis of dry-blended cements offers a more accurate indication of blend homogeneity than performance testing, and knowing the additive content also can be useful in explaining performance variations from one blend to another. Many analyses involve some type of separation technique to isolate the material of interest.

Most retarders and dispersants are chemically structured so that they absorb ultraviolet radiation; hence, these materials can be selectively dissolved or extracted and determined by ultraviolet (UV)-absorption spectrophotometry (ASTM C114, Standard Test Methods for Chemical Analysis of Hydraulic Cement). Extraction techniques have also been applied to fluid-loss additives, although the diverse chemical nature of these materials has necessitated the use of a wide variety of analytical determinations for the separated species. Lost-circulation materials and other additives with large particle size (such as CaCl₂ flakes) frequently are physically separated from a cement blend by sieving, followed by identification and quantification using standard techniques. Determination of salts, extenders, weighting agents, and silica can be performed using a combination of XRD and XRF techniques without separation of these materials from the blend (Simpson, 1988). Accurate quantitative results require considerable care and may not be obtainable for small quantities of the additive.

Optical microscopy has been shown to be a useful tool for the qualitative analysis of cement blends (Reeves et al., 1983). The presence of various cement additives can be confirmed by using a microscope equipped with polarization and fluorescence options, combined with simple laboratory techniques.

**B-7.4 Chemical characterization of set cement**

Many of the same techniques used to characterize neat cement powders and dry-blended cements can be used to examine set cement, although obtaining meaningful descriptions of material requires skillful sample preparation and interpretation of analytical results. Frequently, accurate quantitative analysis is possible only with considerable knowledge about the properties of the components of the material under investigation. A combination of XRD and XRF techniques has been used with some success (Simpson, 1988).

**B-7.5 Analysis of cement mix water**

Procedures for the analysis of oilfield waters are contained in API RP 45, Recommended Practice for Analysis of Oilfield Waters. This document is directed toward the determination of both dissolved and dispersed components in oilfield waters. The reader should consult API RP 45 for detailed information concerning the methods.

In the context of well cementing, prejob testing of cement slurries is frequently performed with a mix-water sample from the job location. Depending upon the test results, the cement-slurry composition may be adjusted to obtain the desired performance. In cases in which problems have occurred during a cement job, mix-water samples are often analyzed in an effort to determine why difficulties were experienced.

The most common chemical variables that are known to affect the performance of Portland cement slurries include

- pH
- alkalinity
ammonia
chloride
iron
organic acids
sulfate.

These variables can either affect the hydration and setting of Portland cement itself or interfere with cement additives.

The analytical methods involved in mix-water testing vary depending upon the analyte. In larger laboratories, techniques such as AAS and ICP are commonly used to determine metallic species. Organics are determined by Fourier transform infrared spectroscopy (FTIR) or chromatographic methods. Wet chemistry methods are also used. In smaller laboratories, or at field locations, ion-specific electrode meters or portable titration kits are frequently employed to determine inorganic and some organic species.

B-8 Summary
The technology currently available for testing well cements is sophisticated; nevertheless, there is much room for improvement. Consequently, energy companies, service companies, and instrument manufacturers are engaged in research to improve existing techniques or to develop new procedures and equipment to simulate well conditions more accurately. Many methods or devices are proprietary, so their use is often limited to the company that invented the method.

Table B-4 provides references to procedures that are presently available to all industry laboratories.

B-9 Acronym list

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>AAS</td>
<td>Atomic absorption spectrometry</td>
</tr>
<tr>
<td>API</td>
<td>American Petroleum Institute</td>
</tr>
<tr>
<td>BET</td>
<td>Brunauer-Emmett-Teller</td>
</tr>
<tr>
<td>BHCT</td>
<td>Bottomhole circulating temperatures</td>
</tr>
<tr>
<td>BHST</td>
<td>Bottomhole static temperature</td>
</tr>
<tr>
<td>CHA</td>
<td>Cement hydration analyzer</td>
</tr>
<tr>
<td>DTA</td>
<td>Differential thermal analysis</td>
</tr>
<tr>
<td>FTIR</td>
<td>Fourier transform infrared spectroscopy</td>
</tr>
<tr>
<td>ICP</td>
<td>Inductively coupled plasma spectroscopy</td>
</tr>
<tr>
<td>ISO</td>
<td>International Organization for Standardization</td>
</tr>
<tr>
<td>ISRM</td>
<td>International Society for Rock Mechanics</td>
</tr>
<tr>
<td>LVDT</td>
<td>Linear variable differential transformer</td>
</tr>
<tr>
<td>PUNDIT</td>
<td>Portable ultrasonic nondestructive digital indicating tester</td>
</tr>
<tr>
<td>RP</td>
<td>Recommended Practice</td>
</tr>
<tr>
<td>TGA</td>
<td>Thermogravimetric analysis</td>
</tr>
<tr>
<td>UCA</td>
<td>Ultrasonic cement analyzer</td>
</tr>
<tr>
<td>UCS</td>
<td>Uniaxial compressive strength</td>
</tr>
<tr>
<td>UV</td>
<td>Ultraviolet</td>
</tr>
<tr>
<td>XRD</td>
<td>X-ray diffraction</td>
</tr>
<tr>
<td>XRF</td>
<td>X-ray fluorescence</td>
</tr>
</tbody>
</table>
Table B-4. Summary of Test Procedures for Well Cements

<table>
<thead>
<tr>
<th>Test Category</th>
<th>Equipment or Methods</th>
<th>References</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sampling</td>
<td>Mechanical splitter Tube sampler Diverted flow sampler</td>
<td>ASTM C702 API RP 10B/ISO 10426-2 Gerke et al., 1985</td>
</tr>
<tr>
<td>Slurry preparation</td>
<td>Two-speed propeller mixer</td>
<td>API RP 10B/ISO 10426-2</td>
</tr>
<tr>
<td>Thickening time</td>
<td>Atmospheric consistometer Pressurized consistometer</td>
<td>API RP 10B/ISO 10426-2</td>
</tr>
<tr>
<td>Fluid loss</td>
<td>High-pressure fluid-loss cell using 325-mesh screen</td>
<td>API RP 10B/ISO 10426-2</td>
</tr>
<tr>
<td>Compressive strength</td>
<td>A 2-in. × 2-in. curing mold, placed in a water bath or in a pressurized autoclave Hydraulic press</td>
<td>API RP 10B/ISO 10426-2</td>
</tr>
<tr>
<td></td>
<td>UCA</td>
<td>Rao et al., 1982</td>
</tr>
<tr>
<td>Mechanical properties</td>
<td>Curing equipment Compression load frame Axial and radial deformation sensors</td>
<td>ASTM C39, ASTM C49/C49M-04</td>
</tr>
<tr>
<td>Free fluid</td>
<td>250-mL graduated cylinder</td>
<td>API RP 10B/ISO 10426-2</td>
</tr>
<tr>
<td>Permeability</td>
<td>Water permeameter</td>
<td>API RP 10B/ISO 10426-2</td>
</tr>
<tr>
<td>Rheology</td>
<td>Rotational viscometer (couette type) Rotational viscometer (Searl type)</td>
<td>API RP 10B/ISO 10426-2 API RP 13B Orban and Parcevaux, 1986</td>
</tr>
<tr>
<td>Static gel strength</td>
<td>Rotational viscometer (couette type)</td>
<td>API RP 10B/ISO 10426-2</td>
</tr>
<tr>
<td>Expansion and shrinkage</td>
<td>Bar mold Cylindrical sleeves Annular ring mold Membrane test</td>
<td>ASTM C151 ISO 10426-5</td>
</tr>
<tr>
<td></td>
<td>CHA test</td>
<td>API TR 10TR</td>
</tr>
<tr>
<td>Spacer, wash, and cement compatibility</td>
<td>Rotational viscometer (couette type) with pressurized consistometer, fluid-loss cell, pressurized autoclave, and hydraulic press</td>
<td>API RP 10B/ISO 10426-2</td>
</tr>
<tr>
<td>Portland cement phase analysis</td>
<td>Wet chemical methods, XRD, XRF, AA, or ICP phases, calculated by Bogue equations</td>
<td>Aldridge, 1982 Bogue, 1929</td>
</tr>
<tr>
<td>Particle analysis of Portland cement</td>
<td>Blaine permeameter Wagner turbidimeter BET Brunauer et al., 1938 Laser light scattering</td>
<td>ASTM C204 ASTM C115 BET Brunauer et al., 1938 Wertheimer and Wilcock, 1976</td>
</tr>
<tr>
<td>Specific gravity of Portland cement</td>
<td>Le Châtelier flask Pycnometer</td>
<td>ASTM C188 ASTM C114</td>
</tr>
<tr>
<td>Chemical analysis of mix water</td>
<td>Wet chemical method AAS ICP</td>
<td>API RP 45 Simpson, 1988</td>
</tr>
</tbody>
</table>
C-1 Introduction
Calculations are an essential part of a cement job design, because they determine the properties of a cement system—density, yield, volume of mix water, and proportions of additives. In addition, depending upon the type of cement job, calculations are necessary to determine the slurry-volume requirements and pressures exerted by various fluids during the treatment. In this appendix, five categories of calculations are discussed.

- Cement-slurry properties
- Primary cement job design
- Squeeze cement job design
- Cement plug design
- Foamed cement job design

U.S. customary units are used for oilfield calculations in many areas of the world. Accordingly, the calculations presented in this appendix are in U.S. units. Conversion factors to Système Internationale (SI) units appear at the end of this appendix.

The proportions of cements and additives are traditionally expressed in the industry as “weights.” “Mass” is the correct term; nevertheless, in this appendix, the traditional term will be used.

C-2 Cement-slurry properties
American Petroleum Institute (API) Specification 10A (2002, Specifications for Cements and Materials for Well Cementing, and the corresponding International Organization for Standardization (ISO) 10426-1 publication specify an amount of water to be mixed with each class of oilwell cement (Table C-1). The API water concentrations are expressed by weight of cement (BWOC), and the corresponding slurry densities and yields are used for testing to verify that a cement conforms to the API performance specifications (Chapter 2). The API water concentrations are not intended to be a recommendation for field application, because the use of additives modifies the performance properties and makes it necessary to adjust the water content.

| Table C-1. API/ISO Cement-Slurry Specifications for Oilwell Cements† |
|-----------------|---------------------|-----------------|-----------------|
| Cement Class    | Mix Water (%BWOC)  | Slurry Density  | Yield (ft²/sk [m²/t]) |
| A               | 46                  | 15.6 [1,870]    | 1.18 [0.355]        |
| B               | 46                  | 15.6 [1,870]    | 1.18 [0.355]        |
| C               | 56                  | 14.8 [1,770]    | 1.32 [0.397]        |
| D               | 38                  | 16.45 [1,970]   | 1.05 [0.316]        |
| E               | 38                  | 16.45 [1,970]   | 1.05 [0.316]        |
| F               | 38                  | 16.45 [1,970]   | 1.05 [0.316]        |
| G               | 44                  | 15.8 [1,890]    | 1.15 [0.346]        |
| H               | 38                  | 16.45 [1,970]   | 1.05 [0.316]        |

† Reproduced courtesy of the American Petroleum Institute.

The mix-water concentrations are mainly a function of the cements’ surface areas. When cement additives are present in the system, the water concentrations necessary to obtain the desired cement-slurry properties will vary. The important cement-slurry properties affected by the mix-water concentration and the presence of additives include slurry density (for well control and avoiding lost circulation), free water, sedimentation, rheology, compressive strength, fluid-loss control, and permeability. This appendix presents methods for calculating the proportions of materials for the various types of cement systems.

C-2.1 Specific gravity of Portland cement
The specific gravity of Portland cement varies between 3.10 and 3.25, depending upon the raw materials used in its manufacture. For the cement-slurry calculations to be precise, one should measure the specific gravity of the cement to be used on a specific job (Appendix B). In this appendix, a specific gravity of 3.14 is assumed in all calculations.
C-2.2 Absolute and bulk volumes

The volume of a particulate material is expressed in two ways. The *absolute volume* is the volume occupied only by the material itself and does not include the volume of air surrounding the particles. The *bulk volume* is the sum of the volumes occupied by the material and its surrounding air.

In the United States, Portland cement normally has a bulk volume of 1 ft³ for 94 lbm, which is commonly referred to as a sack. The absolute volume occupied by a 94-lbm sack of cement is 3.59 U.S. gal or 0.48 ft³, assuming a specific gravity of 3.14. Other cements such as commercial lightweight formulations or calcium aluminate cement have different absolute and bulk volumes. A list of bulk and absolute volumes of several common cements is presented in Table C-2.

<table>
<thead>
<tr>
<th>Material</th>
<th>Absolute Volume (gal/lbm [m³/t])</th>
<th>Specific Gravity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Barite</td>
<td>0.0278 [0.231]</td>
<td>4.33</td>
</tr>
<tr>
<td>Bentonite</td>
<td>0.0454 [0.377]</td>
<td>2.65</td>
</tr>
<tr>
<td>Coal (ground)</td>
<td>0.0925 [0.769]</td>
<td>1.30</td>
</tr>
<tr>
<td>Gilsonite</td>
<td>0.1123 [0.935]</td>
<td>1.06</td>
</tr>
<tr>
<td>Hematite</td>
<td>0.0244 [0.202]</td>
<td>4.95</td>
</tr>
<tr>
<td>Ilmenite</td>
<td>0.0270 [0.225]</td>
<td>4.44</td>
</tr>
<tr>
<td>Silica sand</td>
<td>0.0454 [0.377]</td>
<td>2.65</td>
</tr>
<tr>
<td>NaCl (above saturation)</td>
<td>0.0556 [0.463]</td>
<td>2.15</td>
</tr>
<tr>
<td>Fresh water</td>
<td>0.1198 [1.000]</td>
<td>1.00</td>
</tr>
</tbody>
</table>

Table C-2. Cement Volume Factors

<table>
<thead>
<tr>
<th>Cement</th>
<th>Sack Weight (lbm)</th>
<th>Bulk Volume (ft³/sk [m³/t])</th>
<th>Absolute Volume (gal/lbm [m³/t])</th>
</tr>
</thead>
<tbody>
<tr>
<td>API Classes A through H</td>
<td>94</td>
<td>1.0 [0.301]</td>
<td>0.0380 [0.317]</td>
</tr>
<tr>
<td>TXI™ Lightweight†</td>
<td>75</td>
<td>1.0 [0.377]</td>
<td>0.0425 [0.355]</td>
</tr>
<tr>
<td>Ciment Fondu Lafarge‡</td>
<td>87.5</td>
<td>1.0 [0.323]</td>
<td>0.0373 [0.312]</td>
</tr>
<tr>
<td>LUMNITE§</td>
<td>94</td>
<td>1.0 [0.301]</td>
<td>0.0380 [0.317]</td>
</tr>
</tbody>
</table>

† TXI is a trademark of Texas Industries, Inc.
‡ Ciment Fondu Lafarge is a trademark of Lafarge Aluminates.
§ LUMNITE is a trademark of Heidelberger Calcium Aluminates.

The absolute and bulk volumes of cement additives are available from literature published by the major cementing service companies. A listing of such information for some commonly used cementing materials is shown in Table C-3. This table should not be used for slurry design purposes. Cementing companies may obtain materials from different sources; consequently, the absolute and bulk volumes may vary.

Materials that dissolve in water do not occupy as much space as their dry absolute volumes. For soluble additives like retarders, dispersants, and fluid-loss additives, which are added in relatively small amounts, the difference is negligible. Salt (NaCl), however, is usually added in much larger concentrations; consequently, the difference must be taken into account. This point is discussed later.

C-2.3 Concentrations of additives

The concentrations of most solid cement additives are expressed as a percentage BWOC. This method is also used for water. For example, if 35% (BWOC) silica sand is used in a cement blend, the amount for each sack of cement is 94 lbm × 0.35 = 32.9 lbm of silica sand. This results in 94 + 32.9 = 126.9 lbm of total mix. The true percent of silica sand in the mix is

\[
\frac{32.9}{126.9} \times 100 = 25.9\%.
\]

In the case of cement/fly ash blends, the fly ash is considered to be part of the cementitious material because it reacts with calcium hydroxide and contributes C-S-H phase to the set cement matrix (Chapter 3). Therefore, additive concentrations are expressed by weight of cement plus fly ash, and the abbreviation “BWOC” is used.

In some cases, additive concentrations are given by weight of blend (BWOB). This convention is useful when the blend is a complex mixture of cement and other bulk components.

Salt is a special exception. It is added by weight of mix water (BWOW). In addition, weighting materials such as barite are often added on a “pounds per sack (lbm/sk)” basis. This is done for convenience, because it eliminates the need to convert from percent BWOC to pounds in the bulk plant.

Liquid additive concentrations are commonly expressed in gallons per sack of cement (gal/sk) [liters per SI ton (L/t)] of cementitious material.
C-2.4 Slurry density and yield

The slurry density is calculated by adding the weights of the cement-system components, and dividing that sum by the total of their absolute volumes. In other words, to determine the slurry density in lbm/gal, divide the total weight in pounds of cement, water, and additives by the total volume in gallons of cement, water, and additives (Eq. C-1).

\[ \rho_{\text{slurry}} = \frac{m_{\text{cem}} + m_{\text{water}} + m_{\text{add}}}{V_{\text{cem}} + V_{\text{water}} + V_{\text{add}}} \]  

(C-1)

where

- \( m \) = weight
- \( V \) = volume.

The yield of a cement system is the volume occupied by one unit of cement plus all of the additives and the mix water. For cement measured in sacks, the yield is expressed in cubic feet per sack (ft³/sk) [or cubic meters per SI ton (m³/t)]. The yield is then used to calculate the number of sacks required to achieve the desired fill in the annulus. Most slurry density calculations are performed on the basis of one sack of cement (94 lbm) (or SI ton). This simplifies the calculation of the slurry yield.

Example calculation

Consider a slurry composed of Class G cement plus 44% water (94 lbm × 0.44 = 41.36 lbm water).

<table>
<thead>
<tr>
<th>Component</th>
<th>Weight (lbm)</th>
<th>Absolute Volume (gal/lbm)</th>
<th>Volume (gal)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cement</td>
<td>94</td>
<td>0.0382</td>
<td>3.59</td>
</tr>
<tr>
<td>Water</td>
<td>41.36</td>
<td>0.1198</td>
<td>4.96</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>135.36</strong></td>
<td></td>
<td><strong>8.54</strong></td>
</tr>
</tbody>
</table>

\[ \rho_{\text{slurry}} = \frac{135.36 \text{ lbm}}{8.54 \text{ gal}} = 15.84 \text{ lbm/gal} \]

The slurry yield, \( Y_{\text{slurry}} \), is now determined by dividing the total volume of the slurry per 94-lbm sack of cement (8.54 gal) by the conversion factor of 7.48 gal/ft³.

\[ Y_{\text{slurry}} = \frac{8.54 \text{ gal/sk}}{7.48 \text{ gal/ft}^3} = 1.14 \text{ ft}^3/\text{sk} \]

Another important calculation is the amount of mix water required for the cementing operation. This is necessary to ensure that enough water is available at the wellsite. It is simply the number of gallons calculated as above, multiplied by the number of sacks of cement to be mixed.

Most additives are handled in the same manner. Often, when the calculations are performed by hand, the additives present in minor amounts (less than 1%) are ignored. Today, most laboratories use computers to calculate the slurry mixes and the density and to determine the amounts of additives to use for laboratory testing. All additives are taken into consideration.

Example calculation

Consider a slurry composed of Class G cement + 35% silica flour + 1% solid fluid-loss additive + 0.2 gal/sk liquid dispersant + 44% water.

<table>
<thead>
<tr>
<th>Component</th>
<th>Weight (lbm)</th>
<th>Absolute Volume (gal/lbm)</th>
<th>Volume (gal)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cement</td>
<td>94</td>
<td>0.0382</td>
<td>3.59</td>
</tr>
<tr>
<td>Water</td>
<td>41.36</td>
<td>0.1198</td>
<td>4.96</td>
</tr>
<tr>
<td>Silica flour</td>
<td>32.9</td>
<td>0.0454</td>
<td>1.49</td>
</tr>
<tr>
<td>Fluid-loss additive</td>
<td>0.94</td>
<td>0.0932</td>
<td>0.088</td>
</tr>
<tr>
<td>Liquid dispersant</td>
<td>1.97</td>
<td>0.1014</td>
<td>0.20</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>171.17</strong></td>
<td></td>
<td><strong>10.32</strong></td>
</tr>
</tbody>
</table>

\[ \rho_{\text{slurry}} = \frac{171.17 \text{ lbm}}{10.32 \text{ gal}} = 16.59 \text{ lbm/gal} \]

\[ Y_{\text{slurry}} = \frac{10.32 \text{ gal/sk}}{7.48 \text{ gal/ft}^3} = 1.38 \text{ ft}^3/\text{sk} \]

C-2.4.1 Special additives

Salt

As mentioned earlier, NaCl concentration is commonly expressed as a percentage BWOW. Because it is used at high concentrations, NaCl must be considered in both density and yield calculations. The absolute volume of NaCl dissolved in water is less than its dry absolute volume, and it varies with concentration (Table C-4).
Example calculation

Consider a slurry composed of Class G cement + 37.2% NaCl (BWOW) + 44% water. What are the slurry density and the yield?

94 lbm cement × 0.44 = 41.36 lbm water
41.36 lbm water × 0.372 = 15.39 lbm NaCl

Referring to Table C-4, the absolute volume of NaCl at a concentration of 37.2% BWOW is 0.0442 gal/lbm. Thus, the calculation can be completed as follows.

\[
\rho_{\text{slurry}} = \frac{150.75 \text{ lbm}}{9.22 \text{ gal}} = 16.31 \text{ lbm/gal}
\]

\[
Y_{\text{slurry}} = \frac{9.22 \text{ gal/sk}}{7.48 \text{ gal/ft}^3} = 1.24 \text{ ft}^3/\text{sk}
\]

For other concentrations of salt, the corresponding absolute volume factor for the concentration would be used in the above calculation.

Fly ash

As discussed in Chapter 3, fly ash is a pozzolanic extender that is often used to replace part of the cement. A special convention defined by the API (Recommended Practice 10B, [Recommended Practice for Testing Well Cements] Section 17) is used to describe fly ash/cement blends. Such mixtures are normally written as ratios of the absolute-volume contributions of the two components. A ratio of 35:65 refers to 35% fly ash and 65% cement (the first number always represents the fly ash and the second the cement). Other common ratios are 50:50 and 75:25. The quantity of fly ash necessary to prepare 3.59 gal (absolute volume) of cement blend may be calculated from the following formula.

\[
m_{\text{flyash}} = m_{\text{cemrepl}} \left( \frac{\gamma_{\text{flyash}}}{\gamma_{\text{cem}}} \right)
\]  

(C-2)

where

\[m = \text{weight}\]

\[\gamma = \text{specific gravity}.

The weight of the cement replaced, \(m_{\text{cemrepl}}\), is 94 lbm minus the amount of cement remaining. For a 35:65 fly ash/cement blend, this is 94 lbm – (0.65 × 94 lbm) = 32.9 lbm. Thus, for a 35:65 fly ash/cement blend, using a cement with a specific gravity of 3.14 and a fly ash with a specific gravity of 2.46, the required weight of fly ash is

\[
m_{\text{flyash}} = 32.9 \text{ lbm} \times \frac{2.46}{3.14} = 25.8 \text{ lbm}.
\]

The weight of cement, \(m_{\text{cem}}\), is

\[
m_{\text{cem}} = 0.65 \times 94 \text{ lbm} = 61.1 \text{ lbm}.
\]

The mixture of 25.8 lbm of fly ash with 61.1 lbm of cement weighs 86.9 lbm. This weight is referred to as the equivalent sack (abbreviated as eq sk), because the absolute volume of the blend is 3.59 gal. For such systems, additive concentrations are calculated as a function of the equivalent sack, not a 94-lbm sack of Portland cement. In the above case, 1% of an additive (BWOC) would mean 1% of an 86.9-lbm eq sk.
Fly ashes vary widely, and the specific gravity must be determined for each. The water requirements for the different fly ashes will vary according to desired performance properties, fineness, and the chemical compositions of both the fly ash and cement.

Outside the United States, ratios of fly ash and cement are referred to using other conventions. Users should check to ensure consistency of use in communications.

**Example calculation**

Consider a slurry consisting of a 50:50 fly ash/Class G blend plus 2% bentonite and 54% water ($\gamma_{flyash} = 2.48$; therefore, absolute volume = 0.0483).

\[
m_{cement} = 94 \text{ lbm} - (0.50 \times 94 \text{ lbm}) = 47.0 \text{ lbm}
\]

\[
m_{flyash} = 47.0 \text{ lbm} \times \frac{2.48}{3.14} = 37.12 \text{ lbm}
\]

\[
m_{cement} = 0.50 \times 94 \text{ lbm} = 47.0 \text{ lbm}
\]

\[
m_{eqsk} = 37.12 \text{ lbm} + 47.0 = 84.12 \text{ lbm}
\]

\[
m_{water} = 0.54 \times 84.12 = 45.47 \text{ lbm}
\]

<table>
<thead>
<tr>
<th>Component</th>
<th>Weight (lbm)</th>
<th>Absolute Volume (gal/lbm)</th>
<th>Volume (gal)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cement</td>
<td>47</td>
<td>0.0382</td>
<td>1.79</td>
</tr>
<tr>
<td>Fly ash</td>
<td>37.12</td>
<td>0.0483</td>
<td>1.79</td>
</tr>
<tr>
<td>Bentonite</td>
<td>1.88</td>
<td>0.0452</td>
<td>0.086</td>
</tr>
<tr>
<td>Water</td>
<td>45.47</td>
<td>0.1198</td>
<td>5.44</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>131.23</strong></td>
<td><strong>0.1198</strong></td>
<td><strong>9.11</strong></td>
</tr>
</tbody>
</table>

\[
\rho_{slurry} = \frac{131.23 \text{ lbm}}{9.11 \text{ gal}} = 14.41 \text{ lbm/gal}
\]

\[
Y_{slurry} = \frac{9.11 \text{ gal}}{7.45 \text{ gal/ft}^3} = 1.22 \text{ ft}^3/\text{eq sk}
\]

Note that in this case, water and bentonite are determined based on the equivalent sack and the yield is expressed in cubic feet per equivalent sack (ft$^3$/eq sk) to show that it is based on both the cement and the fly ash.

**Bentonite**

As discussed in Chapter 3, bentonite and attapulgite are clay minerals added to develop gel strength and allow the addition of extra water to cement slurries. The resulting slurries are less dense and more economical.

Bentonite can be dry blended with the cement or prehydrated in the mix water. About 30 min is required to hydrate bentonite in fresh water, and the efficiency of the material as an extender is improved up to four times. The ability of bentonite to absorb water is known as its yield. Prehydrated bentonite “yields” four times as efficiently as when it is dry blended. Unfortunately, this has resulted in some confusion concerning calculations involving prehydrated bentonite. The improved efficiency of prehydrated bentonite has no bearing on the slurry density or the yield of a sack of cement. Bentonite calculations are based on the actual amounts of materials that are present in the blend.

In editions before 1989, API Specification 10 recommended the addition of 5.3% water for each percent of bentonite (BWOC). This is only a general guide, because the extending efficiency of bentonite varies from batch to batch. The actual amount of water should be based on the desired performance properties of the cement (e.g., free water, gel strength, etc.) as determined in the laboratory.

**Example calculation**

For a slurry consisting of Class G cement + 2% prehydrated bentonite + 86.4% water, the calculation is performed as follows.

\[
m_{cement} = 94 \text{ lbm}
\]

\[
m_{bentonite} = 1.88 \text{ lbm}
\]

\[
m_{water} = 85.16 \text{ lbm}
\]

\[
\rho_{slurry} = \frac{177.10 \text{ lbm}}{13.40 \text{ gal}} = 13.22 \text{ lbm/gal}
\]

\[
Y_{slurry} = \frac{13.40 \text{ gal}}{7.45 \text{ gal/ft}^3} = 1.79 \text{ ft}^3/\text{eq sk}
\]

For 8% dry-blended bentonite at the same density (90.6% water), the calculation is shown below.

<table>
<thead>
<tr>
<th>Component</th>
<th>Weight (lbm)</th>
<th>Absolute Volume (gal/lbm)</th>
<th>Volume (gal)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cement</td>
<td>94</td>
<td>0.0382</td>
<td>3.59</td>
</tr>
<tr>
<td>Bentonite</td>
<td>7.52</td>
<td>0.0452</td>
<td>0.34</td>
</tr>
<tr>
<td>Water</td>
<td>85.16</td>
<td>0.1198</td>
<td>10.21</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>186.68</strong></td>
<td><strong>0.1198</strong></td>
<td><strong>14.14</strong></td>
</tr>
</tbody>
</table>
For comparison, the yield and mix water for a 13.2-lbm/gal slurry are shown below.

<table>
<thead>
<tr>
<th>Weighting agent</th>
<th>Mix Water (gal/sk)</th>
<th>Yield (ft³/sk)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dry blend</td>
<td>10.21</td>
<td>1.89</td>
</tr>
<tr>
<td>Prehydrated</td>
<td>9.73</td>
<td>1.79</td>
</tr>
</tbody>
</table>

**Example calculation**

For a slurry composed of Class G cement plus 44% water, how much hematite (absolute volume: 0.0242 gal/lbm) is required to prepare a slurry with a density of 18.5 lbm/gal?

Thus, because the calculation was based on one sack of cement, 40.97 lbm of hematite is required per sack to increase the density of the Class G slurry to 18.5 lbm/gal. This may be expressed in pounds per sack (40.97 lbm/sk) or in percent (40.97 lbm/94 lbm × 100 = 43.6% BWOC). The properties of the slurry are also carefully measured to ensure that the slurry will perform as desired. Particularly important are the slurry's rheology, free water, and tendency for the weighting agent to settle.

**C-3 Primary cementing calculations**

Calculations for primary cementing determine the following:

- Cement volume (annular volume) with excess
- Cement density and yield
- Cement mix water
- Displacement to land plug
- Pump pressure to land plug
- Hydrostatic pressure on formation (fracture and pore pressures)
- Pressure to lift casing

**C-3.1 Annular volumes**

Annular volumes are calculated to determine the volume of cement slurry required to fill the annulus to a certain level. Often during the design stage, these calculations are based on the bit size plus an excess volume to account for hole enlargement or losses as determined from experience in a field.
After reaching the casing point, caliper logs should be run and the cement volume adjusted based on the actual hole size. Even with the caliper, it is common practice to use an excess volume to ensure fill-up by cement across all zones requiring isolation. The type of caliper can affect the amount of cement computed and the resulting fill-up by the cement. Two- and three-arm calipers, with arms that operate together, may underestimate—or overestimate in the case of the two-arm caliper—the size of the hole. This is especially true for deviated wells, because the holes tend to be oval. For these situations, four- and six-arm calipers with independently operating arms provide the most accurate hole-size information.

Most logging companies also offer computerized annular volume calculations that are presented on the log. The use of caliper logs for cement-job design is discussed in detail in Chapter 12.

Once the annular volume is calculated, an excess is added (normally 10% to 100%, based on experience in the field), and the number of sacks required to fill this volume is computed based on the yield of the cement.

Excess factors must be based on experience. Normally, the excess is calculated only for the openhole section being cemented. This excess accounts for cement slurry that may be lost into the formation, for an enlarged hole, or for fluid that may be lost from the cement into permeable zones. When returns to the surface are desired or required, additional excess volume may be used to ensure that this is achieved.

Care must be taken in using excess. If the well has weak formations that are close to being fractured, excess cement could raise the top of the cement and may cause the formation to be fractured because of increased hydrostatic and friction pressures.

The final step in calculating the cement-slurry volume is to add the volume of slurry that will remain in the shoe joints between the float collar and the shoe. This is simply the casing volume between the two points.

### C-3.2 Density, yield, and mix water

The mix-water volume, slurry density, and yield are determined as described in Section C-2.4. The cementing service company usually calculates the mix-water volume. This is the sum of the water volumes required for mixing cement, spacers, and preflushes, as well as for displacement. Excess water should also be available at the wellsite for other contingencies.

### C-3.3 Displacement volume to land the plug

The displacement volume to land the plug is simply a calculation of the capacity of the pipe. The length of the pipe (or segments of pipe if the entire string is not the same size or weight) is multiplied by the pipe capacity as given in standard tables. The displacement volume should be that between the pumps and the landing collar. Normally, a small excess volume may be pumped to allow for the compression of entrained air in the fluid and to account for pump inefficiency.

### C-3.4 Pump pressure to land the plug

The pump pressure required to land the plug is the hydrostatic-pressure difference between the fluids in the annulus and the pipe. Depending on the pump rate, additional pressure may be required to overcome friction pressure. U-tube or placement simulators are the best way to determine the friction pressure. Such pressure information is needed to determine the type of pump required, to ensure that the cementing head is adequate, and to avoid bursting the casing.

### C-3.5 Hydrostatic pressure on the formation (fracture and pore pressure)

To ensure the safety of the well, one must determine whether the well will flow or be fractured during or after the cementing treatment. A good first approximation can be obtained by calculating the hydrostatic pressures at the critical points in the wellbore.

Friction pressure is particularly important when determining the possibility of fracturing weak formations. Because the hydrostatic and friction pressures are constantly changing during a primary cement job, the preferred method is to use computerized placement simulators. If such simulators are unavailable, the calculations given below can be used.

To determine the hydrostatic pressure component, the following equation is used.

\[ p_h = 0.052 \rho h, \]  

where

- \( h \) = height of column having density \( \rho \) (ft)
- \( p_h \) = hydrostatic pressure (psi)
- \( \rho \) = density of the fluid (lbm/gal).

Alternatively

\[ p_h = 0.00982 \rho h, \]  

where

- \( h \) = height of column having density \( \rho \) (m)
- \( p_h \) = hydrostatic pressure (kPa)
- \( \rho \) = density of the fluid (kg/m³).

If there are several fluids in the wellbore, this calculation must be performed for each and their respective hydrostatic pressures added. This value should then be compared with the pressures of the critical formations, and should lie between their pore and fracturing pressures.
C-3.6 Example well calculations

The following calculations would be performed for the well depicted in Fig. C-1. Additional well information is given below.

**Well information**
- Surface casing: 13\(\frac{3}{8}\) in. (54.50 lbm/ft) to 1,700 ft
- Openhole size: 12\(\frac{1}{4}\) in. to 4,950 ft
- Drilling mud: 11.50 lbm/gal
- Casing: 9\(\frac{5}{8}\) in. (36.00 lbm/ft)
- Excess required: 25% (over open hole)
- Shoe joint: 42 ft
- Top of cement: 300 ft inside 13\(\frac{3}{8}\)-in. casing
- Top of tail: 4,450 ft
- Lead system: 13.0 lbm/gal (yield: 1.5 ft³/sk)
- Tail system: 16.4 lbm/gal (yield: 1.05 ft³/sk)
- Spacer: 12.5 lbm/gal (volume: 40 bbl)
- Displacement fluid: 11.5 lbm/gal mud
- Weak formation: 3,215-psi fracture pressure at 4,320 ft
- Highest pore pressure: 3,150 psi at 4,800 ft

**Cement volume calculations**

Note: When calculating volume, measured depth is used.

**Lead cement**
- Inside surface casing:
  - Volume between 9\(\frac{5}{8}\)-in. and 13\(\frac{3}{8}\)-in. casings
  
  \[ V_1 = 300 \text{ ft} \times 0.3627 \text{ ft}^3/\text{ft} = 108.8 \text{ ft}^3 \]

  In open hole:
  - Volume between 9\(\frac{3}{8}\)-in. casing and 12\(\frac{1}{4}\)-in. open hole, with 25% excess
  
  \[ V_2 = (4,450 - 1,700) \text{ ft} \times 0.3132 \text{ ft}^3/\text{ft} \times 1.25 = 1,076.6 \text{ ft}^3 \]

  Total lead cement volume:
  
  \[ V_{lead} = V_1 + V_2 = 108.8 + 1,076.6 = 1,185.4 \text{ ft}^3. \]

**Tail cement**
- Open hole:
  - Volume between 4,450 ft and 4,950 ft
  
  \[ V_3 = 500 \text{ ft} \times 0.3132 \text{ ft}^3/\text{ft} \times 1.25 = 195.8 \text{ ft}^3. \]

  Shoe joint:
  
  \[ V_4 = 42 \text{ ft} \times 0.4341 \text{ ft}^3/\text{ft} = 18.2 \text{ ft}^3. \]

  Total tail cement volume:
  
  \[ V_{total} = V_3 + V_4 = 195.8 + 18.2 = 214.0 \text{ ft}^3. \]

**Displacement volume**

\[ V_{disp} = (4,950 - 42) \text{ ft} \times 0.0773 \text{ bbl/ft} = 379.4 \text{ bbl.} \]

**Pump pressure to land the plug**

Note: When calculating pressure, true vertical depth (TVD) is used.

For hydrostatic pressure inside casing \((p_h)_i\):

Mud hydrostatic pressure,

\[ (p_h)_mud = 0.052 \times 11.5 \text{ lbm/gal} \times (4,950 - 42) \text{ ft} = 2,935.0 \text{ psi.} \]

Tail hydrostatic pressure,

\[ (p_h)_{tail} = 0.052 \times 16.4 \text{ lbm/gal} \times 42 \text{ ft} = 35.8 \text{ psi.} \]

\[ (p_h)_i = 2,935.0 \text{ psi} + 35.8 \text{ psi} = 2,970.8 \text{ psi.} \]

For hydrostatic pressure outside casing \((p_h)_o\), the sum of hydrostatic pressures of all annular fluids must be calculated.

Mud: The height of the mud is 1,400 ft less than the length of the spacer. The length of the spacer is 40 bbl \times 15.48 ft/bbl (from standard tables) = 619.2 ft. Thus, the mud height is 1,400 – 619.2 = 780.8 ft.

\[ (p_h)_{mud} = 0.052 \times 11.5 \text{ lbm/gal} \times 780.8 \text{ ft} = 466.9 \text{ psi.} \]
Spacer:

\[ (p_h)^{sp} = 0.052 \times 12.5 \text{ lbm/gal} \times 619.2 \text{ ft} = 402.5 \text{ psi}. \]

Lead cement:

\[ (p_h)^{lead} = 0.052 \times 13.0 \text{ lbm/gal} \times (4,450 - 1,400) \text{ ft} = 2,061.8 \text{ psi}. \]

Tail cement:

\[ (p_h)^{tail} = 0.052 \times 16.4 \text{ lbm/gal} \times (4,950 - 4,450) \text{ ft} = 426.4 \text{ psi}. \]

Total:

\[ (p_h)^o = (p_h)^{mud} + (p_h)^{sp} + (p_h)^{lead} + (p_h)^{tail} = 466.9 + 402.5 + 2,061.8 + 426.4 = 3,357.6 \text{ psi}. \]

Pressure to land plug, \( p_{LP} \) (excluding friction pressure):

\[ p_{LP} = (p_h)^o - (p_h)^i = 3,357.6 - 2,970.8 = 386.8 \text{ psi}. \]

**Hydrostatic pressure on formations**

Fracture pressure: 3,215 psi at 4,320 ft

\[ p_h \text{ at 4,320 ft} = (p_h)^{mud} + (p_h)^{sp} + (p_h)^{lead} \]

(at 4,320 ft)

\[ (p_h)^{lead} \text{ (at 4,320 ft)} = 0.052 \times 13.0 \text{ lbm/gal} \times (4,320 - 1,400) \text{ ft} = 1,973.9 \text{ psi} \]

\[ p_h = 466.9 + 402.5 + 1,973.9 = 2,843.3 \text{ psi}. \]

Therefore, the hydrostatic pressure is 371.7 psi below the fracture pressure.

Pore pressure: 3,150 psi at 4,800 ft

\[ p_h \text{ at 4,800 ft} = (p_h)^{mud} + (p_h)^{sp} + (p_h)^{lead} + (p_h)^{tail} \]

(at 4,800 ft)

\[ (p_h)^{tail} \text{ (at 4,800 ft)} = 0.052 \times 16.4 \text{ lbm/gal} \times (4,800 - 4,450) \text{ ft} = 298.5 \text{ psi} \]

\[ p_h = 466.9 + 402.5 + 2,061.8 + 298.5 = 3,229.9 \text{ psi}. \]

Therefore, the hydrostatic pressure is 79.7 psi above the pore pressure.

**C-3.7 Pressure to lift the casing**

During some cementing treatments, there is a danger that the casing may be pumped or lifted out of the well. Conditions that favor such an occurrence are:

1. lightweight pipe
2. short pipe length
3. large-diameter pipe
4. high-density cement slurries
5. low-density displacement fluids
6. high annular friction pressures
7. bridging in the annulus
8. backpressure.

Conditions 2, 3, and 5 are frequently met when cementing surface or conductor casings. The lifting pressure is calculated as shown below, using the wellbore diagram shown in Fig. C-2.

**Fig. C-2. Wellbore diagram for calculation of pressure to lift casing.**
Under static conditions, if a check valve (float) is used at the end of the casing, the differential force, \( \Delta F \), is calculated with Eq. C-4a.

\[
\Delta F = \left[ (p_{h})_{ann} \times A_{OD} \right] - \left( m_{csg} + m_{fluid} \right), \quad \text{(C-4a)}
\]

where

\( A_{OD} = \) cross-sectional area (in.\(^2\)) of casing outside diameter

\( m_{csg} = \) casing weight (lbm)

\( m_{fluid} = \) weight of fluid inside casing (lbm)

\( (p_{h})_{ann} = \) hydrostatic pressure of annular fluid(s) (lbf/in.\(^2\)).

If the casing is open-ended (no floats), the calculation is different (Eq. C-4b), but the result is the same.

\[
\Delta F = \left[ (p_{h})_{ann} \times (A_{OD} - A_{ID}) \right] + \left[ \left( (p_{h})_{ann} - (p_{h})_{csg} \right) \times A_{ID} \right] - m_{csg}, \quad \text{(C-4b)}
\]

where

\( A_{ID} = \) cross-sectional area (in.\(^2\)) of casing inside diameter

\( (p_{h})_{csg} = \) hydrostatic pressure of fluid(s) in casing (lbf/in.\(^2\)).

When pumping, the pump pressure \( (p_{p}) \) acting on the inner-diameter cross-sectional area \( (A_{ID}) \) must be added to the above equation.

\[
\Delta F = p_{BH} \left( A_{OD} - A_{ID} \right) + (p_{p} \times A_{ID}) - m_{csg}, \quad \text{(C-5a)}
\]

where

\( p_{BH} = \) effective pressure at the bottom of the hole:

\( p_{BH} = (p_{h})_{csg} + p_{p} \).

If \( \Delta F \) is positive, the casing may come out of the well. Working this problem backward, the value of \( p_{p} \) that gives a \( \Delta F \) value of zero is the critical pump pressure above which the casing may be pumped from the well. The service crew should ensure that the pump pressure during the treatment never exceeds this value unless the casing is restrained.

\[
p_{p, \text{max}} = \frac{m_{csg}}{A_{OD}} \left( (p_{h})_{csg} \left( 1 - \frac{A_{ID}}{A_{OD}} \right) \right), \quad \text{(C-5b)}
\]

where \( p_{p, \text{max}} \) = maximum allowable pump pressure.

**Example calculation**

Consider a 13\(\frac{3}{8}\)-in., 61-lbm/ft casing set at 800 ft with 14.8-lbm/gal cement and 8.33-lbm/gal water for displacement. Is there danger of the casing coming out of the well?

Under static conditions, using Eq. C-4b,

\[
\Delta F = \left\{ 0.052 \times 14.8 \text{ lbm/gal} \times 800 \text{ ft} \right\} \left[ \pi \left( \frac{13.375 \text{ in.}}{4} \right)^2 - \left( \frac{12.515 \text{ in.}}{4} \right)^2 \right] + \left\{ 0.052 \times 14.8 \text{ lbm/gal} \times 800 \text{ ft} \right\} \left[ \left( 800 \text{ ft} \times 0.052 \times 8.33 \right) - \left( 0.052 \times 304.2 \text{ lbf/in.}^2 \right) \right] = 10,766 + 33,110 - 48,800 = -4,923 \text{ lbf}
\]

The negative force indicates that there is not enough buoyancy to float the casing under static conditions. The pump pressure to bump the plug is

\[
p_{p} = (14.8 \text{ lbm/gal} - 8.33 \text{ lbm/gal}) \times 0.052 \times 800 \text{ ft} = 269.2 \text{ psi}
\]

This pump pressure balances the hydrostatic-pressure difference between the fluid in the annulus and the fluid in the casing. Equation C-5b is used to calculate the maximum allowable pump pressure to avoid lifting the casing from the well.

\[
p_{p, \text{max}} = \frac{800 \text{ ft} \times 61 \text{ lbm/ft}}{\left( \frac{13.375 \text{ in.}}{4} \right)^2 \times \pi} - \left[ \left( 800 \text{ ft} \times 0.052 \times 8.33 \right) - \frac{\left( 12.515 \text{ in.} \right)^2}{\left( \frac{13.375 \text{ in.}}{4} \right)^2} \right] = 347.33 - 43.13 = 304.2 \text{ lbf/in.}^2
\]

Therefore, for this casing, the pump pressure must be maintained below 304.2 lbf/in.\(^2\), or other precautions should be taken to avoid having the casing come out of the well.

This example uses single fluids in the casing and in the annulus. In practice, there may be several fluids in the annulus at the end of the job (e.g., tail, lead cement, spacer). In such cases, the calculation is worked with the appropriate contributions from the different fluids.

**C-4 Plug balancing**

Cement plugs, especially sidetrack or “kickoff” plugs, are normally balanced in the borehole (Chapter 14). This means that the hydrostatic pressures in the annulus and in the workstring are equal at the time of placement. This is done to prevent U-tubing after cement placement and helps to prevent contamination so that a strong plug will be set. In practice, the cement is frequently slightly underdisplaced from the balance point. This allows cement to fall while the pipe is being pulled, filling up the space that was occupied by the pipe. It also allows the pipe to be pulled without bringing fluids out onto the rig floor.
When balancing a plug, the hydrostatic pressures in the pipe and in the annulus must be equal. To achieve this, the fluids used to displace the cement must be the same fluids that are ahead of the cement, but in the reverse order. The heights of each of the fluids in the pipe and the annulus must be equal (Fig. C-3).

Fig. C-3. Wellbore diagram for plug cementing calculations.

To ensure that the top of the plug is placed at the desired location, sufficient cement is normally run so that the top is well above its desired location. This excess may be left to set and is then removed with the bit before it has developed its full strength. In some cases the excess cement may be reversed out so that the top of the cement plug is at the appropriate location (Fig. C-4).

C-4.1 Equations

**Volume of cement, \( V_{cem} \)**

\[
V_{cem} = L \times S_{oh},
\]

where

- \( L \) = length of column of cement in open hole (ft)
- \( S_{oh} \) = capacity of open hole from standard tables (ft\(^3\)/ft).

**Length of balanced plug, \( L_{cem} \) (with workstring in place)**

\[
L_{cem} = \frac{V_{cem}}{S_{ann} + S_{tub}},
\]

where

- \( S_{ann} \) = capacity of annulus between tubing or drillpipe and open hole (ft\(^3\)/ft)
- \( S_{tub} \) = capacity of tubing or drillpipe (ft\(^3\)/ft).

Fig. C-4. Reversing of excess cement during plug cementing.

**Volume of spacer behind the cement, \( V_{sp2} \)**

\[
V_{sp2} = \frac{V_{sp1}}{S_{ann}} \times S_{tub},
\]

where

- \( V_{sp1} \) = volume of spacer ahead of the cement.

**Displacement volume, \( V_{disp} \)**

\[
V_{disp} = S_{tub} \times \left[ D - (L_{cem} + L_{sp2}) \right],
\]

where

- \( D \) = depth of workstring (bottom of cement plug) (ft)
- \( L_{sp2} \) = length of spacer behind (ft) = \( V_{sp2}/S_{tub} \).

C-4.2 Example calculations

The well in question is shown in Fig. C-5.

**Well data**

- Openhole size: 8\(\frac{1}{2}\) in.
- Hole capacity (\(S_{oh}\)) = 0.3941 ft\(^3\)/ft
- Drillpipe: 4 in., 14.0 lbm/ft
- Pipe capacity (\(S_{tub}\)) = 0.01084 bbl/ft or 0.06084 ft\(^3\)/ft
- Annular capacity (\(S_{ann}\)) = 0.0546 bbl/ft or 0.3068 ft\(^3\)/ft
- Spacer ahead of cement (\(V_{sp1}\)): 10 bbl
**Volume of cement**

\[ V_{cem} = L \times S_{oh} = 500 \times 0.3941 \, \text{ft}^3/\text{ft} = 197.1 \, \text{ft}^3 \]

**Length of balanced plug**

\[ L_{cem} = \frac{V_{cem}}{S_{ann} + S_{tub}} = \frac{197.1 \, \text{ft}^3}{0.3068 + 0.06084 \, \text{ft}^3/\text{ft}} = 536.1 \, \text{ft} \]

**Volume of spacer behind the cement**

\[ V_{sp2} = \frac{V_{sp1} \times S_{tub}}{S_{ann}} = \frac{10 \, \text{bbl}}{0.0546 \, \text{bbl/ft}} \times 0.01084 \, \text{bbl/ft} = 2.0 \, \text{bbl} \]

**Displacement volume**

\[ V_{disp} = S_{tub} \times \left[ D - (L_{cem} + L_{sp2}) \right] \]

\[ = 0.01084 \, \text{bbl/ft} \times \left[ 7,500 \, \text{ft} - (536.1 \, \text{ft} + 2.0 \, \text{bbl/0.01084 \, bbl/ft}) \right] \]

\[ = 0.01084 \, \text{bbl/ft} \times 6,779 \, \text{ft} = 73.5 \, \text{bbl} \]

Note that the use of the wrong hole size or inaccurate excess volumes may result in an improperly balanced plug, and the top of the plug may be at the wrong depth.

---

**C-5 Squeeze cementing**

Squeeze cementing involves two separate sets of calculations:
- volumes during the treatment
- pressures at various points in the wellbore during various stages of the treatment.

The volumes calculated for a squeeze treatment are:
- cement-slurry volume (from the estimated void to be filled and/or experience)
- volume to the end of workstring
- casing volume below the workstring
- volume to spot water or cement to the perforations
- volume to spot cement to the tool.

These are simple pipe-volume calculations that take into account the various fluids in the pipe. Measured depths are used when calculating volumes.

Pressure calculations ensure the safety of the well and determine the anticipated pressure to squeeze the well. These include:
- pressure to kill the well
- pressure to inject into the void (to avoid fracturing [maximum pressure limit] or to fracture if desired)
- bottomhole pressure (at various stages of the treatment)—the sum of the hydrostatic pressure and pump pressure, minus the friction pressure†
- squeeze pressure—an established increment over injection pressure
- maximum surface pressure safely applied to the annulus
- forces on the casing at the packer
- maximum allowable squeeze pressure
- maximum allowable pressure to reverse circulate fluids from the wellbore.

When calculating pressures, TVDs are used.

Ideally, fracturing is not required and the final squeeze pressure is the only required calculation. The final squeeze pressure calculation is based on the injection pressure. Normally, it is 500 or 1,000 psi (3,448 or 6,895 kPa) above the injection pressure (Chapter 14). In some cases, because of well operations required before the cement setting, it is necessary to apply a higher squeeze pressure. Reversing out excess cement is a typical example. In this case, because of the cement column in the tubing, the hydrostatic pressure is greater than the desired final squeeze pressure. Before beginning reverse circulation, the squeezed perforations must be tested to the corresponding pressure.

---

**C-5.1 Example calculations**

Most squeeze-cementing calculations involve simple volumetrics or hydrostatics; however, several of the calculations require further explanation and are demonstrated with an example. The example wellbore is illustrated in Fig. C-5.

### C-5.1.1 Forces on the casing at the packer

There are pressures on the casing at the packer from two directions. The greater pressure is on the outside of the casing, \( P_{ext} \), tending to collapse it (Fig. C-5). This pressure is a combination of the hydrostatic pressure plus the pumping pressure. If the annulus is not open at the surface, or if there is a bridge, the external pressure is calculated by

\[ P_{ext} = P_p + \left[ 0.052 \times (D_1 + D_2) \times \rho_1 \right] - \left( 0.052 \times D_2 \times \rho_2 \right) \]

\[ \text{(C-10)} \]

†Because of low pump rates, the friction pressure is usually negligible during a squeeze treatment.
If it is not certain whether there is communication to surface, or if a bridge may be near the surface, the most severe case should be assumed and Eq. C-10 should be used.

To offset this pressure, it is sometimes necessary to apply pump pressure, $p_{\text{ann}}$, to the annulus between the casing and the workstring. This pressure must be sufficient to prevent the collapse of the casing, which may be in poor condition if it has been in the well a long time.

$p_i$ is the sum of the pressure applied to the annulus, $p_{\text{ann}}$, and the hydrostatic pressure, $p_h$, of the fluid in the workstring/casing annulus. This pressure must be greater than or equal to the difference between the collapse pressure of the casing (adjusted for its condition) and the external pressure, $p_{\text{ext}}$. The applied pressure must not exceed the burst pressure of the casing (adjusted for its condition) at any point, the highest differential pressure being at the surface.

In the example (Fig. C-5), the required final pump pressure is expected to be 3,900 psi. The workover fluid is 8.5-lbm/gal brine (annular fluid, preflush, and displacement fluid). The packer is at 4,200 ft. Using Eq. C-10,

$$p_{\text{ext}} = p_p + \left[0.052(D_i + D_2)\rho_1 - 0.052D_2\rho_2\right]$$

$$= 3,900 + (0.052 \times 4,500 \times 8.5) - (0.052 \times 300 \times 8.5)$$

$$= 5,756 \text{ psi.}$$

If cement remains in the pipe at the end of the squeeze, the hydrostatic pressure contribution of the cement and the brine must be taken into account.

With a collapse pressure rating of 4,910 psi, there must be at least 846 psi on the inside of the casing at the packer to prevent collapse. The hydrostatic pressure of the 8.5-lbm/gal brine is 1,856 psi, so the requirement is exceeded by 1,010 psi and should be safe if the casing is new and undamaged. Depending on the condition of the casing, the operator may desire a larger safety margin and therefore require that pressure be maintained on the annulus. In addition, to make the appropriate calculation, one must determine the extent to which the collapse pressure rating of the casing has deteriorated.

If cement remains in the pipe at the end of the squeeze, the hydrostatic pressure contribution of the cement and the brine must be taken into account.
C-5.1.2 Maximum surface pressure safely applied to the annulus
As discussed above, in some squeeze treatments, it is necessary to apply pressure to the annulus between the workstring and the casing to avoid collapsing the casing at the packer. The burst rating of the casing must be evaluated—and downgraded for old or used casing—to ensure that the casing will not be damaged. Normally, the worst conditions will be at the surface, with essentially no external pressure and the internal pressure being the pressure applied to the tubing/casing annulus. However, the effect of the condition of the casing may be worse deeper in the well if the casing is corroded or worn.

C-5.1.3 Maximum allowable squeeze pressure
Before the squeeze treatment, the maximum allowable squeeze pressure must be determined, considering the placement technique selected for the treatment and the integrity of all the pipe. If the placement technique involves fracturing the formation before cement placement, the integrity of the pipe is the main concern. If the treatment is performed without fracturing, the formation fracturing pressure must not be exceeded. Of course, the pressure to which the pipe and the formation are exposed is the total of the hydrostatic pressure and the pump pressure. Once the maximum allowable bottomhole pressure has been determined, the hydrostatic pressure of the displacing fluids (and any cement column in the pipe) must be subtracted to calculate the maximum allowable surface pressure during the squeeze.

C-5.1.4 Maximum allowable pressure when reversing out
The final set of pressure calculations involves determining the pressures to which the well will be exposed while reverse circulating fluids out of the well. In some cases, the only fluid reversed out will be the workover fluid. In others, cement may be reversed out.

The critical areas to be considered during this process are casing at the surface (burst), the tubing (collapse), and the squeezed interval itself. If reversing cement, it is best to assume that no cement was injected into the formation and that all the cement is in the tubing. The calculations are a simple matter of determining the fill of each fluid in the pipe and the hydrostatic pressures of these fluids in the pipe and in the annulus. The difference in hydrostatic pressure between the pipe and the annulus is the required pump pressure (not taking into account friction pressure) and is the pressure to which the casing will be exposed. This pressure must be compared to the burst rating of the casing (appropriate to its condition).

The total hydrostatic pressure in the workstring must be considered. This includes all cement in the workstring plus any between the workstring and the perforations. If this pressure is greater than the final squeeze pressure, consideration should be given to a higher squeeze pressure. This is not necessary for the squeeze itself but is necessary to ensure that the squeeze will not be damaged by the reversing process. In the case of small-diameter workstrings, the friction pressure may be significant. Calculation of friction pressure is best performed by placement simulators but can be done manually with a calculator (Chapter 4). In any event, to protect the casing, a limit should be set on the pump pressure applied to reverse fluids.

C-6 Calculations for foamed cement jobs
Most cementing companies use computer programs to design foamed cement jobs; however, it is useful to know how to perform the calculations manually. As discussed in Chapter 7, foamed cement jobs can be divided into two types (depending on the method of scheduling the gas phase): constant nitrogen (or air) ratio and constant density. During a constant-nitrogen-ratio job, the nitrogen is added to the base cement slurry at a constant rate (standard cubic feet [scf]/bbl of slurry). Because of compression, this method results in cement with variable density—lightest at the top, heaviest at the bottom. A constant-density job is one in which several stages of foamed cement, each with a different volume ratio of nitrogen to slurry, are used. The nitrogen-to-slurry ratios are calculated so that each stage will have the same average density at its final position in the annulus; however, the density varies within each stage because of differences in hydrostatic pressure within the stage. In this section, the design calculations for the constant-density method are presented. The same calculations may be used to design a constant-rate job. In that case, the entire interval is considered as one stage.

The following items are calculated to design a foamed cement job.
- Minimum fracture pressure (less a safety factor) and location
- Hydrostatic pressure of the fluids above the weak zone(s) (if the tail slurry is above the weak zone, it must be included)
- Allowable average density of the foamed cement (to meet the fracture-pressure limitation)
- Number of stages
- Hydrostatic pressure at the midpoint of each stage
- Nitrogen requirement for each stage based on the midpoint hydrostatic pressure
Foam quality (or gas ratio) for each stage
Yield of the foamed cement for each stage
Volume of each stage (from length of stage and caliper log)
Hydrostatic pressure as each successive stage of foamed cement enters the annulus (this is necessary because the gas ratio of the first stages of foamed cement is lower at greater depths owing to gas compression; thus, their density as they pass the shoe will be higher)
Pump schedule including
- base slurry volume
- nitrogen ratio
- nitrogen volume
- nitrogen pump rate
- foamer pump rate

Once these calculations are made, a series of tables and graphs should be constructed to show the parameters for each stage. The following example illustrates this procedure.

**Minimum fracture pressure**

\[ p_{f_{\text{min}}} = \left( 0.512 \text{ psi/ft} \times 7,700 \text{ ft} \right) - 500 \text{ psi (safety factor)} \]

\[ = 3,442 \text{ psi} \]

**Hydrostatic pressure of the fluids (mud and spacer) ahead of the foamed cement**

\[ p_h = 0.052 \times \left( (1,755 \text{ ft} \times 9.2 \text{ lbm/gal}) \right. \]
\[ + \left. (745 \text{ ft} \times 8.6 \text{ lbm/gal}) \right) \]

\[ = 1,173 \text{ psi} \]

**Allowable average density of the foamed cement**

The allowable average density of the foamed cement in the annulus, \( \rho_1 \), is calculated as below.

\[ \rho_1 = \frac{p_{f_{\text{min}}} - p_h}{0.052 \times h} \]

\[ = \frac{3,442 \text{ psi} - 1,173 \text{ psi}}{0.052 \times (7,700 \text{ ft} - 2,500 \text{ ft})} \]

\[ = 8.4 \text{ lbm/gal} \]

---

**Design data**

- Total depth: 9,000 ft
- Lost circulation: 5,000 to 7,700 ft
- Fracture gradient: 0.512 psi/ft at 7,700 ft (equivalent to 9.85 lbm/gal)
- Full circulation: 9.2 lbm/gal mud
- Casing: 5½ in., 17.0 lbm/ft
- Hole caliper: 9¾ in.
- Static temperature: 180°F at 9,000 ft
  165°F at 7,700 ft
- Circulating temperature: 160°F at 7,450 ft
  150°F at 6,350 ft
  140°F at 5,250 ft
  130°F at 4,150 ft
  120°F at 3,050 ft
- Spacer: 745 ft at 8.6 lbm/gal
- Top of tail cement: 8,000 ft
- Top of cement: 2,500 ft
- Base cement density: 14.2 lbm/gal
- Base cement yield: 1.29 ft³/sk

**Fig. C-6.** Wellbore diagram for staged foamed cementing.

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Number of stages
Divide into intervals of 1,000 to 1,500 ft
Total interval is 8,000 – 2,500 ft = 5,500 ft
Divide into 5 stages of 1,100 ft each

Hydrostatic pressure at the midpoint of each stage
\( p_h = p_h \) above stage + \( p_h \) to midpoint of stage

**Stage No. 1 (top)**
\( p_{h1} = 1,173 \text{ psi} \\
+ [(\text{Stage number} - 0.5) \times 1,100 \text{ ft} \times \rho_1 \times 0.052] \\
= 1,173 \text{ psi} + (0.5 \times 1,100 \text{ ft} \times 8.4 \text{ lbm/gal} \times 0.052) \\
= 1,413 \text{ psi} \\

**Stage No. 2**
\( p_{h2} = 1,173 \text{ psi} + (1.5 \times 1,100 \text{ ft} \times 8.4 \text{ lbm/gal} \times 0.052) \\
= 1,894 \text{ psi} \\

**Stage No. 3**
\( p_{h3} = 1,173 \text{ psi} + (2.5 \times 1,100 \text{ ft} \times 8.4 \text{ lbm/gal} \times 0.052) \\
= 2,374 \text{ psi} \\

**Stage No. 4**
\( p_{h4} = 1,173 \text{ psi} + (3.5 \times 1,100 \text{ ft} \times 8.4 \text{ lbm/gal} \times 0.052) \\
= 2,855 \text{ psi} \\

**Stage No. 5 (bottom)**
\( p_{h5} = 1,173 \text{ psi} + (4.5 \times 1,100 \text{ ft} \times 8.4 \text{ lbm/gal} \times 0.052) \\
= 3,335 \text{ psi} \\

Nitrogen requirement for each stage based on the midpoint
Nitrogen density, \( \rho_{N2} \):
\[ \rho_{N2} = (1.724 \times 10^{-3}) \times K_{N2}. \] (C-12)
where
\( K_{N2} \) = nitrogen volume factor (scf/bbl).  
Foamed cement quality, \( Q_{foam} \):
\[ Q_{foam} = 1 - \frac{\rho_{fc} - \rho_{N2}}{\rho_{bs} - \rho_{N2}}, \] (C-13)

where
\( \rho_{bs} \) = base slurry density
\( \rho_{fc} \) = foamed cement density
\( \rho_{N2} \) = nitrogen density.

Foamed cement yield, \( Y_{fc} \) (ft³/sk):
\[ Y_{fc} = \frac{Y_{bs}}{1 - Q_{foam}}. \] (C-14)

where
\( Y_{bs} \) = base slurry yield (ft³/sk).

Annular volume, \( V_{ann} \):
\[ V_{ann} = L \times S_{ann}, \] (C-15)

where
\( L \) = length  
\( S_{ann} \) = annular capacity.  

Cement requirement, \( C \) (sk):
\[ C = \frac{V_{ann}}{Y_{fc}}. \] (C-16)

Nitrogen requirement at conditions in the annulus, \( R_{N2} \):
\[ R_{N2} = V_{ann} \times Q_{foam}. \] (C-17)

The nitrogen requirement refers to the volume required at circulating temperature and pressure. For job-design purposes, this value must be converted to the equivalent volume of nitrogen in standard cubic feet (at standard temperature and pressure [STP]).

Nitrogen volume, \( V_{N2} \), at STP (scf):
\[ V_{N2} = R_{N2} 	imes K_{N2}. \] (C-18)

Stage No. 1, \( p_{h1} = 1,413 \text{ psi} \)
\[ \rho_{N2} = (1.724 \times 10^{-3}) \times K_{N2} = 1.724 \times 10^{-3} \times 476 \text{ scf/bbl} = 0.8206 \text{ lbm/gal} \]

The nitrogen volume factor can be calculated based upon pressure and bottomhole circulating temperature or more easily looked up in standard tables published by most cementing companies.  
Foamed cement quality, \( Q_{foam} \):
\[ Q_{foam} = 1 - \frac{8.4 - 0.8206}{14.2 - 0.8206} = 0.4335. \]
Foamed cement yield, \( Y_{fc} \):
\[
Y_{fc} = \frac{1.29 \text{ ft}^3/\text{sk}}{1 - 0.4335} = 2.28 \text{ ft}^3/\text{sk}.
\]

Annular volume, \( V_{ann} \):
\[
V_{ann} = 1,100 \text{ ft} \times 0.3017 \text{ ft}^3/\text{ft} = 331.9 \text{ ft}^3.
\]

Cement requirement, \( C \) (sk):
\[
C = \frac{331.9 \text{ ft}^3}{2.28 \text{ ft}^3/\text{sk}} = 145.6 \text{ sk}.
\]

Nitrogen requirement, \( R_{N_2} \):
\[
R_{N_2} = 331.9 \text{ ft}^3 \times 0.4335 = 143.9 \text{ ft}^3.
\]

Nitrogen volume, \( V_{N_2} \), at STP:
\[
V_{N_2} = 143.9 \text{ ft}^3 \times 0.178 \text{ bbl/ft}^3 \times 476 \text{ scf/bbl} = 12,192 \text{ scf}.
\]

Similarly, the requirements for the other stages are calculated, and the following table can be built.

<table>
<thead>
<tr>
<th>Stage</th>
<th>Hydrostatic pressure (psi)</th>
<th>Nitrogen density (lbm/gal)</th>
<th>Foamed cement quality</th>
<th>Foamed cement yield (ft³/sk)</th>
<th>Annular volume (ft³)</th>
<th>Cement requirement (sk)</th>
<th>Nitrogen per sack (scf/sk)</th>
<th>Nitrogen requirement (scf)</th>
<th>Total cement requirement</th>
<th>Total nitrogen requirement</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1,413</td>
<td>0.821</td>
<td>0.4335</td>
<td>2.28</td>
<td>331.9</td>
<td>145.6</td>
<td>83.7</td>
<td>12,192</td>
<td>943.3 sk</td>
<td>98,222 scf</td>
</tr>
<tr>
<td>2</td>
<td>1,894</td>
<td>1.069</td>
<td>0.4417</td>
<td>2.31</td>
<td>331.9</td>
<td>143.7</td>
<td>112.6</td>
<td>16,179</td>
<td>943.3 sk</td>
<td>98,222 scf</td>
</tr>
<tr>
<td>3</td>
<td>2,374</td>
<td>1.291</td>
<td>0.4493</td>
<td>2.34</td>
<td>331.9</td>
<td>141.8</td>
<td>140.2</td>
<td>19,878</td>
<td>943.3 sk</td>
<td>98,222 scf</td>
</tr>
<tr>
<td>4</td>
<td>2,855</td>
<td>1.493</td>
<td>0.4564</td>
<td>2.37</td>
<td>331.9</td>
<td>140.0</td>
<td>166.8</td>
<td>23,353</td>
<td>943.3 sk</td>
<td>98,222 scf</td>
</tr>
<tr>
<td>5</td>
<td>3,335</td>
<td>1.677</td>
<td>0.4631</td>
<td>2.40</td>
<td>331.9</td>
<td>138.3</td>
<td>192.5</td>
<td>26,620</td>
<td>943.3 sk</td>
<td>98,222 scf</td>
</tr>
</tbody>
</table>

Hydrostatic pressure as each stage of foamed cement enters the annulus

Actually, hydrostatic pressure should be calculated for the position of each stage immediately above the weak formation(s). Because a job designed for constant density uses a slurry with the lowest concentration of nitrogen in the first stages, these initial stages will be significantly more dense when they pass the weaker formations below. Therefore, to ensure the integrity of the well, the hydrostatic pressure exerted on the weak formations must be calculated and compared to the fracturing pressure of these formations. To do this, the following steps must be followed.

1. Determine the volume occupied by each stage at the weak zone.
2. Calculate its length based on the annular capacity.
3. Calculate the hydrostatic pressure of the fluids in the annulus above.
4. Calculate the hydrostatic pressure of the foamed cement stage(s).
5. Add the results of Steps 3 and 4 to obtain the total hydrostatic pressure.
6. Compare this value to the fracturing pressure of the weak formation.
7. If the results indicate a risk of formation fracturing, consider a constant-nitrogen-rate or a hybrid job. A hybrid job involves several stages of foamed cement with different designed densities.

From the preceding example, this calculation is performed as shown below.

1. Determine the volume occupied by each stage at the weak zone.
   - For Stage No. 1, 145.6 sk or (145.6 \times 1.29 \text{ ft}^3/\text{sk} \times 0.178 \text{ bbl/ft}^3) = 33.4 \text{ bbl} of cement slurry are required.
   - The nitrogen requirement is 12,192 scf.
   - The weak zone is at 7,700 ft.
   - The fluids ahead of the cement are 9.2-lbm/gal mud (0.4784 psi/ft), and 745 ft of spacer at 8.6 lbm/gal (0.4472 psi/ft).
   - Assuming the foamed cement occupies 850 ft (because of compression), the length of the mud column is 7,700 – 850 (cement) – 745 (spacer) = 6,105 ft.
   - The hydrostatic pressure from the mud is 6,105 ft \times 0.4784 \text{ psi/ft} = 2,920 psi, and the hydrostatic pressure from the spacer is 745 ft \times 0.4472 \text{ psi/ft} = 333 psi; thus, the total hydrostatic pressure is 2,920 + 333 = 3,253 psi.
1. Reading from the nitrogen tables, the volume occupied by 12,192 scf of nitrogen is 12.7 bbl at 160°F. Thus, the volume of the foamed cement slurry is 12.7 + 33.4 = 46.1 bbl.

2. Calculate its length based on the annular capacity.
   With an annular capacity of 0.3017 ft³/ft and 46.1 bbl of slurry, the fill-up is
   \[
   \frac{46.1 \text{ bbl}}{0.3017 \text{ ft}^3/\text{ft} \times 0.178 \text{ bbl/ft}^3} = 858 \text{ ft}.
   \]
   If this result had not been close to the assumed foamed cement length of 850 ft (Step No. 1), the calculation would be repeated using an adjusted length.

3. Calculate the hydrostatic pressure of the fluids in the annulus above.
   The height of the mud column is 7,700 – 745 – 858 = 6,097 ft. Therefore, the hydrostatic pressure is 6,097 ft × 0.4784 psi/ft = 2,916.8 psi. For the spacer, the hydrostatic pressure is 745 ft × 0.4472 psi/ft = 333.1 psi.

4. Calculate the hydrostatic pressure of the foamed cement stage(s).
   \[
   \rho_{nc} = 1.724 \times 10^{-3} \times \text{nitrogen volume factor (scf/bbl)}
   = 1.724 \times 10^{-3} \times 950 \text{ scf/bbl}
   = 1.638 \text{ lbm/gal}.
   \]
   The foam quality can be calculated by
   \[
   Q_{foam} = \frac{V_{N_2}}{V_{bs} + V_{N_2}} = \frac{12.7 \text{ bbl}}{12.7 \text{ bbl} + 33.4 \text{ bbl}} = 0.2755
   \]
   The previous equation for foamed cement quality can be rearranged to calculate foamed cement density,
   \[
   \rho_{fc} = (1 - Q_{foam})(\rho_{bs} - \rho_{N_2}) + \rho_{N_2}
   = (1 - 0.2755)(14.2 - 1.638) + 1.638 = 10.74 \text{ lbm/gal}.
   \]
   Therefore, the hydrostatic pressure from foamed cement is 10.74 lbm/gal × 0.052 psi/ft/lbm/gal × 858 ft = 479.2 psi.

5. Add the three hydrostatic pressures to obtain the total hydrostatic pressure.
   2,916.8 psi + 333.1 psi + 479.2 psi = 3,729.1 psi.

6. Compare this value to the fracturing pressure of the weak formation.
   The fracturing pressure of the weak formation is 3,942 psi.
   Note that the pressure calculated in the previous step does not exceed the fracturing pressure of the weak formation but does exceed the safety margin set in the first step. This is what would be expected based on the method for calculating the foamed cement density, based on the fracturing pressure less the safety margin. This calculation should be repeated as each stage passes the weak formation.

Job execution tables

It is helpful for control of the job to construct tables of the pumping schedule containing the following information.

- Base slurry volume
- Nitrogen ratio
- Nitrogen volume
- Nitrogen pump rate
- Foamer pump rate

### Job Schedule per Stage

<table>
<thead>
<tr>
<th>Stage</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base slurry volume (bbl)</td>
<td>33.4</td>
<td>33.0</td>
<td>32.6</td>
<td>32.1</td>
<td>31.8</td>
</tr>
<tr>
<td>Nitrogen ratio (scf/bbl base slurry)</td>
<td>365</td>
<td>490</td>
<td>610</td>
<td>728</td>
<td>837</td>
</tr>
<tr>
<td>Nitrogen volume (scf)</td>
<td>12,192</td>
<td>16,179</td>
<td>19,878</td>
<td>23,353</td>
<td>26,620</td>
</tr>
</tbody>
</table>

### Nitrogen and Foamer Rate

<table>
<thead>
<tr>
<th>Base Slurry Rate (bbl/min)</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nitrogen rate (scf/min)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Stage No. 1</td>
<td>1,095</td>
<td>1,460</td>
<td>1,825</td>
<td>2,190</td>
<td>2,555</td>
</tr>
<tr>
<td>Stage No. 2</td>
<td>1,470</td>
<td>1,960</td>
<td>2,450</td>
<td>2,940</td>
<td>3,430</td>
</tr>
<tr>
<td>Stage No. 3</td>
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<td>Foamer rate (gal/min)</td>
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<td>All stages</td>
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<td>1.74</td>
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### Conversion Factors

<table>
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<th>To Obtain SI Units</th>
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<td>in.</td>
<td>2.54 (25.4)</td>
<td>cm (mm)</td>
</tr>
<tr>
<td>ft</td>
<td>0.305</td>
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<tr>
<td>ft³</td>
<td>0.0283</td>
<td>m³</td>
</tr>
<tr>
<td>bbl</td>
<td>0.159</td>
<td>m³</td>
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<tr>
<td>U.S. gal</td>
<td>3.785 (3.785 × 10⁻³)</td>
<td>L (m³)</td>
</tr>
<tr>
<td>ft²/ft (capacity)</td>
<td>0.0929</td>
<td>m²/m</td>
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<tr>
<td>bbl/ft (capacity)</td>
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<tr>
<td>gal/sk (94 lbm sack)</td>
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<td>ft²/sk (94 lbm sack)</td>
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<td>lbm</td>
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<td>lbm/gal</td>
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<td>lbm/ft (pipe weight)</td>
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<tr>
<td>psi</td>
<td>6.895 (6.895 × 10⁻³)</td>
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<td>psi/ft</td>
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<td>kPa/m</td>
</tr>
<tr>
<td>°F</td>
<td>(°F – 32)/1.8</td>
<td>°C</td>
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### C-7 Acronym list

- API American Petroleum Institute
- BWOB By weight of blend
- BWOC By weight of cement
- BWOW By weight of water
- ISO International Organization for Standardization
- SI Système International
- STP Standard temperature and pressure
- TVD True vertical depth

### C-8 Suggested reading


<table>
<thead>
<tr>
<th>Symbol</th>
<th>Definition</th>
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<tr>
<td>$a$</td>
<td>Activity (Chapter 6)</td>
</tr>
<tr>
<td>$a_{sv}$</td>
<td>Water activity</td>
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<tr>
<td>$A$</td>
<td>Area (Chapters 1, 4, 6, 8, 15; Appendices B, C)</td>
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<tr>
<td>$A_{API}$</td>
<td>API surface area</td>
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<tr>
<td>$A_{ID}$</td>
<td>Cross-sectional area of casing inside diameter</td>
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<tr>
<td>$A_{OD}$</td>
<td>Cross-sectional area of casing outside diameter</td>
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<tr>
<td>$A_{pipe}$</td>
<td>External pipe surface area</td>
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<td>$A$</td>
<td>Signal attenuation (Chapter 15)</td>
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<tr>
<td>$b$</td>
<td>Offset in linear regression (Chapter 4)</td>
</tr>
<tr>
<td>$B$</td>
<td>Correction factor (Chapters 1, 4, 15)</td>
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<td>$B$</td>
<td>Formation volume factor</td>
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<td>$B_{lam}$</td>
<td>Laminar flow correction factor</td>
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<td>$B_{rev}$</td>
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<td>$B_{turb}$</td>
<td>Turbulent-flow correction factor</td>
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<tr>
<td>$c$</td>
<td>Compressibility (Chapters 6, 8, 9)</td>
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<td>$C$</td>
<td>Specific heat (Chapter 8; Appendix B)</td>
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<td>$C$</td>
<td>Cement requirement (Appendix C)</td>
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<tr>
<td>$C$</td>
<td>Circumference (Chapter 15)</td>
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<td>$C_{csg}$</td>
<td>Casing circumference</td>
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<tr>
<td>$d$</td>
<td>Diameter (Chapters 4, 5, 6, 7, 8, 9, 11, 15; Appendices A, B)</td>
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<td>$d^*$</td>
<td>Sample diameter after deformation</td>
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<tr>
<td>$d_{body}$</td>
<td>Outer diameter of liner hanger body</td>
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<td>Casing diameter</td>
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<td>Disk diameter</td>
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<td>Hole diameter</td>
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<tr>
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</tr>
<tr>
<td>$d_o$</td>
<td>Outside diameter</td>
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<tr>
<td>$d_{part}$</td>
<td>Particle diameter</td>
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<tr>
<td>$d_{pipe}$</td>
<td>Pipe diameter</td>
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<td>$d_{slip}$</td>
<td>Slip OD</td>
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<tr>
<td>$d_w$</td>
<td>Pipe diameter at the wall</td>
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<tr>
<td>$D$</td>
<td>Depth (Chapters 6, 9, 11; Appendices B, C)</td>
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<tr>
<td>$D_{boc}$</td>
<td>Depth at bottom of cement</td>
</tr>
<tr>
<td>$D_{bog}$</td>
<td>Depth at bottom of gas zone</td>
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<tr>
<td>$D_{pl}$</td>
<td>Depth of permeable layer</td>
</tr>
<tr>
<td>$D_{toc}$</td>
<td>Depth of top of column</td>
</tr>
<tr>
<td>$D_{tog}$</td>
<td>Depth at top of gas zone</td>
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<tr>
<td>$D_{TV}$</td>
<td>True vertical depth of cement column</td>
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<tr>
<td>$E$</td>
<td>Young’s modulus (Chapters 7, 8, 15; Appendix B)</td>
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<td>$E$</td>
<td>Amplitude (Chapters 6, 15)</td>
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<tr>
<td>$E_1$, $E_2$, $E_3$</td>
<td>CBL amplitude</td>
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<td>$(E_1)_1$</td>
<td>$E_1$ amplitude at Receiver 1</td>
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<tr>
<td>$(E_1)_2$</td>
<td>$E_1$ amplitude at Receiver 2</td>
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<tr>
<td>$(E_1)_{fp}$</td>
<td>$E_1$ amplitude in free pipe</td>
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<tr>
<td>Symbol</td>
<td>Definition</td>
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<td>--------------</td>
<td>---------------------------------------------------------------------------</td>
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<td>$E_{100%ca}$</td>
<td>Amplitude of 100% cemented pipe</td>
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<tr>
<td>$E_{fp}$</td>
<td>CBL amplitude ($E_1$ peak) for free pipe</td>
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<tr>
<td>$E_{meas}$</td>
<td>Measured CBL amplitude ($E_1$ peak) for free pipe</td>
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<tr>
<td>$E_{wave}$</td>
<td>Wave amplitude</td>
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<td>Energy (Chapter 6)</td>
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<td>Activation energy</td>
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<td>$f$</td>
<td>Frequency (Chapter 15)</td>
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<td>$f_0$</td>
<td>Resonant frequency of pipe</td>
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<td>$f$</td>
<td>Factor (Chapters 4, 9, 11, 14, Appendix A)</td>
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<td>$f_c$</td>
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<td>Fanning friction factor</td>
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<td>Fanning friction factor value at critical values of the Reynolds number</td>
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<td>$f_{\tau}$</td>
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<td>Fraction (Chapters 6, 7, 9, 14)</td>
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<td>Solid volume fraction of the cement cake</td>
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<td>Volumetric fraction of gas in the slurry at surface conditions</td>
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<td>Packing volume fraction</td>
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<td>Water volume fraction</td>
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<td>$f_{wV0}$</td>
<td>Initial water volume fraction</td>
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<td>$F$</td>
<td>Force (Chapters 4, 8, 11; Appendices B, C)</td>
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<td>$F_{\text{fail}}$</td>
<td>Load at failure</td>
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<td>Maximum unsupported load that the casing in which a liner hanger is to be set will withstand</td>
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<td>$g$</td>
<td>Acceleration of gravity (Chapters 4, 5, 6, 7, 9, 14; Appendix B)</td>
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<td>$g_z$</td>
<td>$z$ component of gravity acceleration</td>
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<td>$g_{\text{frac}}$</td>
<td>Fracture gradient</td>
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<td>$G$</td>
<td>Shear modulus (Chapter 8)</td>
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<td>$h$</td>
<td>Height or thickness (Chapters 1, 4, 5, 6, 8, 9, 14, 15; Appendices B, C)</td>
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<td>$h_{\text{g}}$</td>
<td>Head height of protuberance</td>
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<td>$h_{\text{cem}}$</td>
<td>Cement slurry height in the annulus</td>
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<td>$h_{\text{comb}}$</td>
<td>Combined thickness of cement sheath and casing</td>
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<td>Casing thickness</td>
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<td>$h_{\text{disk}}$</td>
<td>Disk thickness</td>
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<td>Filtercake thickness</td>
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<td>Cement filtercake thickness</td>
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<td>Mud filtercake thickness</td>
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<td>Formation thickness</td>
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<td>Mud height in the annulus</td>
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<td>Height of node building up inside casing</td>
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<td>Permeable layer height</td>
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<td>$h_{\text{sp}}$</td>
<td>Spacer height in the annulus</td>
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<td>Wave intensity (Chapter 15)</td>
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<td>( l )</td>
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<td>Permeability (Chapters 1, 6, 8, 9, 14; Appendix B)</td>
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<td>Reservoir permeability</td>
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<td>Coefficient (Chapters 5, 6, 8, 9, 14, 15; Appendix C)</td>
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<td>Coefficient related to degree of cement-phase hydration</td>
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<td>Definition</td>
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<td>$K_{os}$</td>
<td>Osmotic coefficient</td>
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<td>Transmission coefficient</td>
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<td>Coefficient related to active matter content $x$</td>
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<td>Standard spring calibration constant (Chapter 4)</td>
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<td>Length or distance (Chapters 1, 4, 5, 6, 8, 9, 15; Appendices A, B, C)</td>
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<td>$L^*$</td>
<td>Sample length after deformation</td>
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<tr>
<td>$L_1$</td>
<td>Average distance between pins when sleeve is empty (Appendix B)</td>
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<tr>
<td>$L_2$</td>
<td>Average distance between pins when sleeve is expanded (Appendix B)</td>
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<tr>
<td>$L_1, L_2$</td>
<td>Distance between receivers (Chapter 15)</td>
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<td>Eccentering limit</td>
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<td>Final distance between pins (Appendix B)</td>
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<td>$L_i$</td>
<td>Initial distance between pins (Appendix B)</td>
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<td>$L_{sp2}$</td>
<td>Length of spacer behind cement</td>
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<td>Weight of cement</td>
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<td>Weight in equivalent sacks</td>
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<td>$m_{flyash}$</td>
<td>Weight of fly ash</td>
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<td>$m_{water}$</td>
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<tr>
<td>$M$</td>
<td>A hardening parameter (Chapter 8)</td>
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<td>$n$</td>
<td>Power-law index (Chapters 4, 5, 7; Appendix A)</td>
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<td>$n'$</td>
<td>Local power-law index</td>
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<td>$n_{\text{cem}}$</td>
<td>Power-law index of cement</td>
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<tr>
<td>$n_{\text{mud}}$</td>
<td>Power-law index of mud</td>
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<td>$n$</td>
<td>Stress vector in Fig. 8-1 (Chapter 8)</td>
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<td>Bingham number of the displacing fluid</td>
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<td>Number of cone segments cut</td>
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<tr>
<td>$N_{\text{pads}}$</td>
<td>Number of cone pads</td>
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<td>$N_{He}$</td>
<td>Hedström number</td>
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<td>$(N_{He})_{HB}$</td>
<td>Generalized Hedström number for Herschel-Bulkley fluids</td>
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<td>Reynolds number</td>
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<td>$N_{Re1}$, $N_{Re2}$</td>
<td>Critical values of Reynolds number</td>
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<td>$(N_{Re})_{AV}$</td>
<td>Annular Reynolds number</td>
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<td>$(N_{Re})_{BG}$</td>
<td>Bingham Reynolds number</td>
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<td>Herschel-Bulkley Reynolds number</td>
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<td>$(N_{Re})_i$</td>
<td>Reynolds number of fluid $i$</td>
</tr>
<tr>
<td>$(N_{Re})_{MR}$</td>
<td>Metzner and Reed Reynolds number</td>
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<tr>
<td>$(N_{Re})_{\text{ecc}}$</td>
<td>Reynolds number for eccentric annuli</td>
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<tr>
<td>$N_{\text{slip seg}}$</td>
<td>Number of slip segments cut</td>
</tr>
<tr>
<td>$N_{sp}$</td>
<td>Slurry performance number</td>
</tr>
</tbody>
</table>

$p$ | Pressure (Chapters 1, 4, 5, 6, 8, 9, 11, 14, 15; Appendices B, C) |
$p_{\text{ann}}$ | Annular pressure |
$p_{\text{API}}$ | API pressure |
$p_{\text{back}}$ | Backpressure |
<table>
<thead>
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<th><strong>Symbol</strong></th>
<th><strong>Definition</strong></th>
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</thead>
<tbody>
<tr>
<td>$p_{BH}$</td>
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<tr>
<td>$p_{burst}$</td>
<td>Bursting pressure</td>
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<td>$p_{cem}$</td>
<td>Cement slurry pressure</td>
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<tr>
<td>$p_{col}$</td>
<td>Collapse pressure</td>
</tr>
<tr>
<td>$p_{con}$</td>
<td>Confined pressure value</td>
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<tr>
<td>$p_e$</td>
<td>Effective filtration pressure</td>
</tr>
<tr>
<td>$p_{ext}$</td>
<td>External pressure</td>
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<td>$p_{thh}$</td>
<td>Flowing bottomhole pressure</td>
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<tr>
<td>$p_{min}$</td>
<td>Minimum fracture pressure</td>
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<tr>
<td>$p_{frac}$</td>
<td>Fracturing pressure</td>
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<tr>
<td>$p_{gas}$</td>
<td>Gas pressure</td>
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<tr>
<td>$p_{gauge}$</td>
<td>Gauge pressure</td>
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<tr>
<td>$p_h$</td>
<td>Hydrostatic pressure</td>
</tr>
<tr>
<td>$(p_h)_{ann}$</td>
<td>Hydrostatic pressure of annular fluids</td>
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<tr>
<td>$(p_h)csg$</td>
<td>Hydrostatic pressure of fluids inside casing</td>
</tr>
<tr>
<td>$(p_h)i$</td>
<td>Hydrostatic pressure inside casing</td>
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<tr>
<td>$(p_h)lead$</td>
<td>Hydrostatic pressure for lead slurry</td>
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<tr>
<td>$(p_h)mud$</td>
<td>Mud hydrostatic pressure</td>
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<tr>
<td>$(p_h)ho$</td>
<td>Hydrostatic pressure outside casing</td>
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<td>$(p_h)sp$</td>
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<td>$(\Delta p)_{min}$</td>
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<td>$p_{overburden}$</td>
<td>Overburden pressure</td>
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<td>$p_{p,\text{max}}$</td>
<td>Maximum allowable pump pressure</td>
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<td>$(p_{pore})_{\text{max}}$</td>
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<td>Safe pressure, the lesser of $p_{sc}$ or $p_{sc}$</td>
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<tr>
<td>(r_{\text{hole}})</td>
<td>Hole radius</td>
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<tr>
<td>(r_i)</td>
<td>Inner radius</td>
</tr>
<tr>
<td>(r_{i+L})</td>
<td>Inner radius plus length of pin</td>
</tr>
<tr>
<td>(r_o)</td>
<td>Outer radius</td>
</tr>
<tr>
<td>(r_{\text{perf}})</td>
<td>Perforation radius</td>
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<tr>
<td>(r_w)</td>
<td>Pipe or annulus inner radius</td>
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<td>$t^*_{break}$</td>
<td>Dimensionless breakthrough time</td>
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<td>$t_0$</td>
<td>Initial time</td>
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<td>$t_{100Be}$</td>
<td>Time to 100 Bearden units of consistency</td>
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<td>$t_{30Be}$</td>
<td>Time to 30 Bearden units of consistency</td>
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<td>$t_{API}$</td>
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<td>$t_{break}$</td>
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<td>$t_{crit}$</td>
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<td>$t_{disp}$</td>
<td>Time to displace leading edge of cement slurry to bottom</td>
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<td>$t_u$</td>
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<td>$t_{gel}$</td>
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</table>

$V$ Wellbore volume times porosity (Chapter 14)

$w$ Slot width or a local annular gap (Chapters 1, 4, 5)

$w_{min}$ Minimum annular gap

$w$ Deposition factor (Chapter 14)

$x$ Normalized distance to the pipe axis or to the plane of symmetry of the slot (Chapter 4; Appendix A)
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<td>$\varepsilon_{pl}$</td>
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<td>$\varepsilon_r$</td>
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<td>ε&lt;sub&gt;z&lt;/sub&gt;</td>
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<tr>
<td>ε&lt;sub&gt;θ&lt;/sub&gt;</td>
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<tr>
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<td>γ&lt;sub&gt;xz&lt;/sub&gt;</td>
<td>Shear strain, xz direction</td>
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<td>$\gamma_{flyash}$</td>
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<tr>
<td>$\gamma_L$</td>
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<tr>
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<tr>
<td>$(\mu_p)_c$</td>
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<td>$\rho_{df}$</td>
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<td>$\rho_{eq}$</td>
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<td>Total applied stress</td>
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<tr>
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<tr>
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<tr>
<td>$\sigma_z$</td>
<td>Total stress exerted at a given linear depth, z</td>
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<td>Shear stress at wellbore wall that causes pressure to reach critical value for gas entry</td>
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<td>$\tau_{rz}$</td>
<td>rz component of shear stress tensor</td>
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<td>Shear stress at the wall</td>
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<td>( \tau_y )</td>
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<td>( (\tau_y)_c )</td>
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