

POWER BOILERS

**A GUIDE TO SECTION I OF
THE ASME BOILER AND
PRESSURE VESSEL CODE**

Second Edition

by

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DEDICATION TO THE SECOND EDITION

The authors of the Second Edition dedicate this book to their esteemed colleague on Section I, the late Martin D. Bernstein. Martin (Marty to most of his good friends) served with passion and dedication from the early 1970s until his untimely passing in 2002, at which time he was Vice-chairman of the Committee. In addition to his duties on Section I, Marty was an active member of the ASME Committee on Safety Valve Requirements, serving as Vice-Chairman from 1990 and Chairman in 2000. We were fortunate to know Marty and to have had the pleasure of his company during the frequent Boiler Code weeks over the years.

DEDICATION TO THE FIRST EDITION

The authors dedicate this book to their distinguished colleague on Subcommittee I, the late Walter Harding of Combustion Engineering. From the 1950s until his retirement in the 1980s, Walter Harding served with distinction on the ASME Boiler and Pressure Vessel Committee in many capacities, including Chairman of the Main Committee. An engineer of the greatest integrity, Harding was an inspiring role model for younger committee members, extremely knowledgeable, ever helpful, cheerful, and the possessor of a fine sense of humor. We were fortunate to have had the privilege of serving with him.

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FOREWORD

In 1986, the ASME Professional Development Department approached original author Martin Bernstein and asked him to develop and teach a 2-day professional development course on Section I of the ASME Boiler and Pressure Vessel Code, whose title is now Rules for Construction of Power Boilers. The task of developing course notes and the prospect of teaching all day for 2 days with no relief were somewhat daunting, so Bernstein enlisted the help of Lloyd Yoder, his long-time friend and colleague on BPV Committee on Power Boilers I (BPV I), the ASME committee that governs Section I. The two then collaborated on the preparation of appropriate notes and from 1986 to just prior to Martin's death in March, 2002, taught a 2-day course for the ASME at various locations within the United States and overseas. During that time, they expanded and refined the course notes, covering material of interest to those who have been taking the course — design engineers; project managers; architect engineers; engineers from boiler manufacturers, boiler operators, and insurance and inspection agencies; and others involved with power boilers and the ASME Code governing their construction.

The introduction in the brochure for that 2-day professional development course on Section I explained that Section I contains the rules for the construction of power boilers, but that those rules are accompanied by very little explanation. Thus, the course was intended to provide a basic understanding of those rules, their intent, and how they are applied, interpreted, and revised. This book is a greatly expanded version of those course notes, with broader and more detailed coverage on various topics of interest to those involved with power boilers.

Author John MacKay was asked to take on the task of updating this book. He recruited Jim Pillow, friend and BPV I colleague, to assist with the effort. John and Jim accepted the challenge as a way to honor the accomplishments of Martin and Lloyd and to carry on their work. Both Martin and Lloyd spent their careers working for major boiler manufacturers and decades serving in various capacities on the ASME Boiler and Pressure Vessel Committees. Likewise, John and Jim have spent their careers involved in the design, manufacture, and installation of power boilers and continue their decades of service as members of the ASME Boiler and Pressure Vessel Committees. This book is a compendium of the authors' knowledge and experience.

The design and construction of power boilers involves the use of other sections of the ASME Code besides Section I, and the use of those other sections is explained in this book when appropriate. Section II, Materials, provides detailed specifications for materials and welding consumables, as well as tabulations of design stresses and material properties, such as yield strength and tensile strength as a function of temperature. Section V, Nondestructive Examination, contains a series of standards that provide the methodology for conducting the various nondestructive examinations used in Section I construction. Section IX, Welding and Brazing Qualifications, provides the information necessary to qualify the weld procedures and the welders required for Section I construction. In a rather unusual arrangement, the construction rules for boiler piping are found partly in Section I and partly in the B31.1 Power Piping Code. This has led to considerable misunderstanding and confusion, and the authors have endeavored to provide a clear explanation of these rules and the potential pitfalls to be avoided.

Both authors of this edition are long-time members of the ASME committee that governs Section I, BPV I. In the course of its duties, that committee answers a steady flow of questions from all over the world on the application and interpretation of Section I. The authors have thus participated in or are familiar with

Section I interpretations and Code changes going back more than three decades. Since 1978 the ASME has been publishing those interpretations, but they are not widely or readily available, nor is their background known by most people. A useful feature of this book is that as a particular subject is covered, many important interpretations dealing with that subject are cited and discussed. These interpretations form a very useful body of reference information, since they explain or clarify rules that have led to inquiries from the public and provide insight into the views of BPV I.

Although Section I nominally covers only the new construction of power boilers, this book goes further and contains a chapter on rules covering boilers in service, such as those found in the National Board Inspection Code. The original authors also found that participants in their course on Section I were interested in the subject of creep and fatigue damage during boiler life and the related subject of boiler life extension. Accordingly, a chapter providing an overview of those subjects has been included.

When the ASME in 1911 began the development of a boiler code, it addressed a serious safety problem of that time by formulating a uniform set of rules for the construction of steam boilers, rules that could be adopted by all the states. That set of rules eventually became Section I. The interesting history of steam power in the nineteenth century provides the background for the development of Section I and is described in Appendix I.

The organization and operation of the ASME Boiler and Pressure Vessel Committees is a subject not likely to be found on a best-seller list. Nevertheless, some knowledge of the workings of the committees may prove useful for those submitting inquiries or requests for Code changes, or for Code Cases. Appendix II provides a description of how the committees operate.

Those unfamiliar with the ASME Code may at first be confused by a number of terms commonly used in it. Examples include third party inspection, Authorized Inspector, Authorized Inspection Agency, Certified Individual, jurisdiction, Maximum Allowable Working Pressure (MAWP), boiler proper, boiler proper piping, boiler external piping, interpretation, Code Case, certification, and Certificate of Authorization (to use a Code symbol stamp). The authors explain these terms in the text wherever appropriate.

Although the ASME Boiler and Pressure Vessel Code changes relatively slowly, it does change continuously and, at times, profoundly. The rate of change in recent years seems to have increased, perhaps due to technological innovation and international competition. Thus, while it provides a substantial body of information and an explanation of the rules as they now exist, this book can never provide the last word. The Code Edition covered in the original issue of this book was the 1998 Edition of Section I, which was comprised of the 1995 Edition with Addenda through 1997. In a departure from previous practice, the 1998 Edition included the first Addenda to that Edition, the 1998 Addenda, as explained further in Chapter 2. This edition of this book covers the 2010 Edition with the 2010 Addenda. The authors are confident that the book will provide the industry with a very useful reference and guide to Section I.

INTRODUCTION

It is helpful to begin the study of Power Boilers, Section I of the ASME Boiler and Pressure Vessel Code, with some discussion of its character and philosophy. According to the dictionary, the term **code** has several meanings: a system of principles or rules; a body of laws arranged systematically for easy reference. Section I is primarily a system of rules. When, in 1911, the ASME decided that the country needed a boiler code, it assigned a committee and gave it a mandate to formulate standard rules for the construction of steam boilers and other pressure vessels. The first edition of what is now known as Section I was finally approved by the ASME in 1915 and incorporated what was considered the best current practice in boiler construction. However, the guiding principle then, as now, was that these be safety rules.

Part of the Foreword of Section I explains the guiding principles and philosophy of Section I, and also of the Boiler and Pressure Vessel Committees, which continues to administer the Code:

The American Society of Mechanical Engineers set up a committee in 1911 for the purpose of formulating standard rules for the construction of steam boilers and other pressure vessels. This committee is now called the Boiler and Pressure Vessel Committee.

The Committee's function is to establish rules of safety, relating only to pressure integrity, governing the construction of boilers, pressure vessels, transport tanks and nuclear components, and inservice inspection for pressure integrity of nuclear components and transport tanks, and to interpret these rules when questions arise regarding their intent. This code does not address other safety issues relating to the construction of boilers, pressure vessels, transport tanks and nuclear components, and the inservice inspection of nuclear components and transport tanks. The user of the Code should refer to other pertinent codes, standards, laws, regulations, or other relevant documents. With few exceptions, the rules do not, of practical necessity, reflect the likelihood and consequences of deterioration in service related to specific service fluids or external operating environments. Recognizing this, the Committee has approved a wide variety of construction rules in this Section to allow the user or his designee to select those which will provide a pressure vessel having a margin for deterioration in service so as to give a reasonably long, safe period of usefulness. Accordingly, it is not intended that this Section be used as a design handbook; rather, engineering judgment must be employed in the selection of those sets of Code rules suitable to any specific service or need.

*This Code contains mandatory requirements, specific prohibitions, and nonmandatory guidance for construction activities. The Code does not address all aspects of these activities, and those aspects which are not specifically addressed should not be considered prohibited. The Code is not a handbook and cannot replace education, experience, and the use of engineering judgment. The phrase **engineering judgment** refers to technical judgments made by knowledgeable designers experienced in the application of the Code. Engineering judgments must be consistent with Code philosophy and such judgments must never be used to overrule mandatory requirements or specific prohibitions of the Code.*

The Boiler and Pressure Vessel Committee deals with the care and inspection of boilers and pressure vessels in service only to the extent of providing suggested rules of good practice as an aid to owners and their inspectors.

The rules established by the Committee are not to be interpreted as approving, recommending, or endorsing any proprietary or specific design or as limiting in any way the manufacturer's freedom to choose any method of design or any form of construction that conforms to the Code rules.

Certain points in these paragraphs should be stressed. Section I covers the construction, i.e., materials, design, fabrication, examination, inspection, testing, certification, and pressure relief of boilers. That is, it covers new construction only. (Rules covering boilers in service will be discussed later, in Chapter 16.) Although there is general agreement that Section I should apply to new replacement parts, and such parts are usually specified that way, until the appearance of the 1996 Addenda, Section I had no clear provisions dealing with replacement parts other than how they should be documented. Those Addenda included changes to PG-106.8 and PG-112.2.4, which require the manufacturer of replacement parts to state on the data report form (the documentation that accompanies the part; see Chapter 9) the extent to which the company is assuming design responsibility for a replacement pressure part.

Also mentioned in the Foreword is the impracticality of establishing rules addressing in-service deterioration due to operating environments; however, a wide variety of construction rules have been approved from which the manufacturer may select to provide a boiler having a margin for deterioration in service so as to give a reasonably long, safe period of usefulness. This is an acknowledgment of the fact that no equipment lasts forever and that boilers do have a finite life. The mechanisms by which a boiler wears out and the means by which remaining life may be estimated are discussed in Chapter 14.

The Section I rules were based on the best design practice known when they were written and have continued to evolve on the same basis. They have worked well over many years. Rule changes have been made that recognize advances in design and materials, as well as evidence of satisfactory experience. The needs of the users, manufacturers, and inspectors are considered, but safety relating to pressure integrity is always the primary concern.

Another basis for the success of Section I is its committee's insistence that the rules be general and not be interpreted as approving, recommending, or endorsing any proprietary or specific design or limiting a manufacturer's freedom to choose any design or construction that conforms to the Code rules. The committee considers that a manufacturer is ultimately responsible for the boiler design and leaves certain aspects not explicitly covered by Section I to the manufacturer. Traditionally, the manufacturer has recognized and borne the responsibility for such things as functional performance, providing for thermal expansion and support of the boiler and its associated piping and for consideration of thermal stress, wind, and seismic loading.

The useful advice that Section I is not a handbook and cannot replace education, experience, and the use of engineering judgment was added to the Foreword of all sections of the Code in the 1992 Addenda. This overdue advice was added in an attempt to limit the ASME's entanglement in certain disputes among manufacturers, owners, and regulatory authorities regarding the application of the Code.

Further evidence of the flexibility and reasonableness of Section I and another key to its success as a living document is found in the second paragraph of the Preamble:

The Code does not contain rules to cover all details of design and construction. Where complete details are not given, it is intended that the manufacturer, subject to the acceptance of the Authorized Inspector, shall provide details of design and construction which will be as safe as otherwise provided by the rules in the Code.

This important paragraph provides a way to accept new or special designs for which no rules are given, by allowing the designer to prove to the satisfaction of an Authorized Inspector that the safety of the new design is equivalent to that usually supplied.

According to one of the definitions cited above, a code is a body of laws arranged systematically for easy reference. Although this may be true of Section I, it is not at first easy to use or understand because it is neither a textbook nor an engineering design manual. It is rather a collection of rules that have been revised and expanded over the years with very little accompanying explanation. These rules mandate the fundamental construction features considered necessary for a safe boiler (one that is a safe pressure container), but typically do not provide any advice on how to design a boiler from the standpoint of what size or arrangement of components should be used. There are no provisions dealing with the thermal performance and efficiency of the boiler or how much steam it will produce (other than for some approximate guidelines for judging the adequacy of the pressure relief valve discharge capacity). It is assumed that the boiler manufacturer or designer already has this knowledge, presumably from experience or available technical literature. Many rules seem, and indeed are, arbitrary; but as explained before, they were originally written to incorporate what was considered good practice in the industry.

Section I's method of achieving safe boiler design is a relatively simple one. It requires all those features considered necessary for safety (e.g., water gauge glass, pressure relief valve, pressure gauge, check valve, drain) and then provides detailed rules governing the construction of the various components comprising the boiler, such as tubes, piping, headers, shells, and heads. This approach is analogous to the old saying that a chain is no stronger than its weakest link. For a boiler, the links of the figurative chain can be considered to be the material, the design (formulas, loads, allowable stresses, construction details), fabrication techniques including welding, examination, inspection, testing, overpressure protection and certification by stamping and data reports. If each of these elements meets the appropriate Section I rules, a safe boiler results. The boiler can then be described as a Section I boiler, meaning one constructed to meet all the requirements of Section I of the ASME Boiler and Pressure Vessel Code. An important element of this construction process is a quality control program, intended to assure that the Code has been followed. Each aspect of the process is discussed in this book.

Code construction under the rules of Section I takes place as follows: The ASME certifies a manufacturer (i.e., after appropriate review and acceptance of the manufacturer's facilities, organization, and quality control system, authorizes the manufacturer to engage in Code construction). The manufacturer then constructs, documents, certifies, and stamps the boiler in compliance with the rules of Section I. The manufacturer's activities are monitored and inspected by a third party (the Authorized Inspector, see Chapter 8). The boiler is then acceptable to jurisdictions with laws stipulating ASME construction of boilers. Section IV construction (of heating boilers), Section VIII construction (of pressure vessels), Section X construction (of fiber-reinforced plastic pressure vessels) and Section XII construction (of transport tanks) is carried out in similar fashion.

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SCOPE OF SECTION I, ORGANIZATION, AND SERVICE LIMITS

SCOPE

Section I applies to several types of boilers and components of boilers, such as economizers, superheaters, reheaters, and, in some circumstances, feedwater heaters. Although its title is Rules for Construction of Power Boilers, its scope is somewhat broader. The Preamble to Section I explains that it covers electric boilers, miniature boilers, high-temperature water boilers, heat recovery steam generators, certain fired pressure vessels, and organic fluid vaporizers. Since the precise definitions of these various types of boilers are not generally known, the following definitions, found in footnotes to the Preamble, are helpful:

Power boiler—a boiler in which steam or other vapor is generated at a pressure of more than 15 psi (100 kPa) for use external to itself.

Electric boiler—a power boiler or a high-temperature water boiler in which the source of heat is electricity.

Miniature boiler—a power boiler or high-temperature water boiler in which the limits in PMB-2 are not exceeded. (PMB-2 establishes limits on shell diameter, heating surface, gross volume, and maximum allowable working pressure. See further discussion under Part PMB later in this chapter.)

High-temperature water boiler—a water boiler intended for operation at either pressures in excess of 160 psi (1.1 MPa) or temperatures in excess of 250° F (120°C), or both.

Heat recovery steam generator (HRSG)—a boiler that has as its principal source of thermal energy a hot gas stream having high-ramp rates and temperatures such as the exhaust of a gas turbine.

Fired pressure vessel—reheater, isolable superheaters, and nonintegral separately fired superheaters.

It happens that Section I does not provide an explicit definition of an organic fluid vaporizer. An **organic fluid vaporizer** is a boiler-like device that uses vaporized organic fluid instead of steam as the working fluid. The last paragraph of the Preamble states that a pressure vessel in which an organic fluid is vaporized by the application of heat resulting from the combustion of fuel shall be constructed under the provisions of Section I. (Those provisions are found in Part PVG.) Thus, so far as Section I is concerned, an organic fluid vaporizer is a boiler-like device in which an organic fluid is vaporized as just described. (Note that a key

factor is the vaporization of the organic fluid. If the organic fluid is merely heated without vaporizing, the device does not fall within the scope of Section I; it might fall instead under the scope of Section VIII as a pressure vessel.) The Preamble then provides a notable exception to the Section I definition of an organic fluid vaporizer: “Vessels in which vapor is generated incidental to the operation of a processing system, containing a number of pressure vessels such as are used in chemical and petroleum manufacture, are not covered by the rules of Section I.” Again, if Section I rules do not cover these vessels, what rules do? The answer is the rules of Section VIII, Rules for Construction of Pressure Vessels. Those rules cover all kinds of pressure vessels, including, in some cases, fired pressure vessels.

Although the origin of the above exception to Section I coverage is uncertain, a possible explanation can be offered. Note that the vessel in question would probably be used in a chemical plant or petroleum refinery. Such plants are normally owned and operated by large companies with capable engineering staffs and well-trained operators. Those companies can usually demonstrate a good record of maintenance and safety. Furthermore, vaporizing organic liquids inside pressure vessels is a routine matter for them. They might also argue that it really does not make much difference whether a properly designed vessel is built to the rules of Section I or Section VIII, nor does it matter whether the source of heat is from direct firing, from hot gases that may have given up some of their heat by having passed over heat-transfer surface upstream, or from a hot liquid that is being processed. There are also economic reasons why an owner might prefer a Section VIII vessel over a Section I vessel, as explained later in the discussion of fired versus unfired boilers.

The Preamble does not explain the precise meaning of “vapor generation incidental to the operation of a processing system.” It apparently means the generation of vapor in a vessel or heat exchanger that is part of a processing system in a chemical plant or petroleum refinery where this vapor generation is only a minor or secondary aspect of the principal business of the plant, such as refining oil. Thus, certain equipment normally constructed to Section I rules could, under this exception, be constructed instead to the rules of Section VIII, provided the appropriate authorities in the jurisdiction where the equipment is to be installed have no objection. As will be explained later, these so-called jurisdictional authorities have the last word in deciding which Code section applies (see How and Where Section I Is Enforced in Chapter 2).

There is also some imprecision in the use and meaning of the term **power boiler**. That term is sometimes understood to mean a boiler whose steam is used for the generation of power, as opposed, for example, to a boiler whose steam is used for chemical processing or high-pressure steam heating. However, according to the definition in the Preamble, a boiler that generates steam or other vapor at a pressure greater than 15 psi (100 kPa) for external use is considered by Section I to be a power boiler, irrespective of how the steam might be used. Although exceptions exist, most jurisdictional authorities follow the ASME Code in defining and categorizing boilers and pressure vessels.

Note from the definition of a power boiler that the steam or other vapor generated is for use external to the boiler. This is supposed to distinguish a power boiler from certain other pressure vessels such as autoclaves, which may similarly generate steam or vapor at a pressure greater than 15 psi (100 kPa), but not generally for external use. These pressure vessels, often used as process equipment in the chemical and petroleum industries, and for cooking or sterilization in other industries, are designed to meet the rules of Section VIII.

From the Preamble definitions, it is apparent that a high-temperature water boiler, which generally produces pressurized hot water for heating or process use, is not considered a power boiler. However, as a practical matter, the particular characterization of a device by Section I as a power boiler or something else is less important than the fact that it is indeed covered by Section I rules.

The Preamble explains that the scope of Section I covers the **complete boiler unit**, which is defined as comprising the **boiler proper** and the **boiler external piping**. This very important distinction needs further explanation. The term **boiler proper** is an unusual one, chosen to distinguish the boiler itself from its external piping. The **boiler proper** consists of all the pressure parts comprising the boiler, such as the drum, the economizer, the superheater, the reheater, waterwalls, steam-generating tubes known as the boiler bank,

various headers, downcomers, risers, and transfer piping connecting these components. Any such piping connecting parts of the boiler proper is called **boiler proper piping**. The **boiler external piping** is defined by its extent, as that piping that begins at the first joint where the boiler proper terminates and extends to and includes the valve or valves required by Section I.

The importance of all these definitions and distinctions is that the construction rules that apply to the boiler proper and boiler proper piping are somewhat different from those that apply to the boiler external piping. This is explained in Chapter 4, Distinction Between Boiler Proper Piping and Boiler External Piping.

The Preamble also explains that the piping beyond the valves required by Section I is not within the scope of Section I. Thus, these valves define the boundary of the boiler, and Section I's jurisdiction stops there. Note that the upstream boundary of the scope of Section I varies slightly, depending on feedwater valve arrangements. Different valve arrangements are required for a single boiler fed from a single source, as opposed to two or more boilers fed from a common source, with and without bypass valves around the required regulating valve (see PG-58.3.3, PG-58.3.4, and the solid and dotted lines shown in Fig. PG-58.3.1.a). The required boiler feed check valve is typically placed upstream of the feed stop valve, except that on a single boiler-turbine unit installation, the stop valve may be located upstream of the check valve. Changes in the Section I boundary can have some significance in the choice of design pressure for the feedwater piping and valves, which is governed by the rules of B31.1, Power Piping (see paragraph 122.1.3). These several topics are discussed further in Chapter 5.

An exception to this coverage of boiler piping is found in the treatment of the hot and cold reheat piping between the boiler and a turbine, which is excluded from the scope of Section I. Occasionally, someone asks how and why the reheat piping was left outside the scope of Section I. The explanation offered some years ago by a senior member of the committee was as follows: Although some use of reheaters dates back to the earliest days of Section I, the rising steam pressures used in large utility boilers in the 1940s led to their increased use. The reheat piping became larger, heavier, and more complex. In those days, the General Electric Company and Westinghouse made virtually all the turbines used in the United States, and it was customary for those turbine manufacturers to take responsibility for the design of the reheat piping. When some committee members suggested that it might be time to consider bringing the reheat piping into the scope of Section I, those two companies objected. On the basis of their long, successful experience, they persuaded the committee that such a change was unnecessary and that they were perfectly capable of designing that piping. Thus, the reheat piping remained outside the scope of Section I.

In the late 1980s, failures of hot reheat piping occurred at two major utilities, with injuries and loss of life. This reopened the question of Section I coverage for reheat piping and whether the failed piping, designed in the 1960s, might not have failed had it been within the scope of Section I. (Current Section I rules call for all boiler components to be manufactured, inspected, certified, and stamped under a quality control system, although the quality control system requirement was not imposed until 1973. Moreover, any piping within Section I's scope is generally inspected yearly, with the rest of the boiler, although finding potential leaks or failures under the insulation is not so readily accomplished.) However, investigators were not able to agree on the causes of the failures, and the idea of bringing the reheat piping within Section I's scope died for lack of support.

Code coverage of this reheat piping and also of piping beyond the boiler external piping varies. Normally in power plant design, the owner or the architect-engineer will select the B31.1, Power Piping Code, for the reheat piping and that code or the B31.3, Process Piping Code (formerly called the Chemical Plant and Petroleum Refinery Piping Code), for the piping beyond the boiler external piping. At other times, the jurisdiction (state or province) may have laws mandating use of one or the other of these two codes to cover piping that is not within Section I's scope.

Some unfired steam boilers are constructed to the requirements of Section VIII, as permitted by the Preamble. Section VIII rules deal only with the vessels themselves; they do not deal with any piping attached to the vessels. In such cases, the choice of an appropriate design code for the piping may be left to the plant designers, or the jurisdictional authorities may mandate a particular piping code.

THE ORGANIZATION OF SECTION I

The original Edition of Section I was not well organized. The first half, some 36 pages, dealt with material specifications. This was followed by 25 pages of design formulas and construction details, seven pages on safety valves, and six pages on piping, valves, fittings, hydrostatic testing, and stamping. Rules for heating boilers were contained in a second seven-page section. Appendix A 20 contained rules for existing installations and further useful supplementary information on riveted joints and stayed surfaces. Over the years, the contents changed as portions were moved into other sections of the Code, and more and more provisions were added. In 1965, following a precedent set by BPV VIII, BPV I completely reorganized Section I into its present, improved arrangement of parts, in which each part covers a major topic or particular type of boiler or other Section I device.

That reorganization was merely a reshuffling of the existing requirements, with no technical change from the previous version; however, there have been significant additions since then. For example, Part PB, Requirements for Boilers Fabricated by Brazing, was added with the 1996 Addenda and provided rules previously missing from Section I for boilers fabricated by brazing. Part PHRSG, Requirements for Heat Recovery Steam Generators, was added with the 2007 Addenda and provides special rules for a unique, highly cycled type of power boiler.

While this philosophy supporting continual updating of rules for construction of power boilers is commendable, it should be noted that not all efforts to reorganize the contents of Section I come to fruition. This is illustrated by the attempt to gain broader acceptance of Section I by making it more user friendly to jurisdictions other than those in the United States and Canada. In 2003, a task group was formed and charged with the task of reorganizing Section I so as to separate the conformity assessment activities (i.e., Code symbol stamping, data reports, application for certification, and qualification of third party inspectors) and the technical requirements. After no small effort by the task group and an in-depth review and lengthy consideration by the ASME Boiler and Pressure Vessel Committee's Executive Committee, it was decided not to take action on the task group's recommendations at that time. The task group suggested adding an appendix to Section I (as well as to the other Code sections) that contained all the conformity assessment rules. Work continues on separating the requirements, but the format will likely be a distinct section applicable to all Boiler and Pressure Vessels Codes.

The following is the present day arrangement of Section I:

Foreword

Statements of Policy

Personnel

Preamble

Part PG

General Requirements for All Methods of Construction

Part PW

Requirements for Boilers Fabricated by Welding

Part PR

Requirements for Boilers Fabricated by Riveting

Part PB

Requirements for Boilers Fabricated by Brazing

Part PWT

Requirements for Watertube Boilers

Part PFT

Requirements for Firetube Boilers

Part PFH

Optional Requirements for Feedwater Heater (When Located Within Scope of Section I Rules)

Part PMB

Requirements for Miniature Boilers

Part PEB

Requirements for Electric Boilers

Part PVG

Requirements for Organic Fluid Vaporizers

Part PHRSG

Requirements for Heat Recovery Steam Generators

Mandatory Appendices

Appendix I

Preparation of Technical Inquiries to the Boiler and Pressure Vessel Committee

Appendix II

Standard Units for Use in Equations

Appendix III

Criteria for Reapplication of An ASME Code Symbol Stamp

Appendix IV

Local Thin Areas in Cylindrical Shells and Spherical Segments of Heads

Non-mandatory Appendices

<i>Appendix A</i>	Explanation of the Code Containing Matter Not Mandatory Unless Specifically Referenced to in the Rules of the Code
<i>Appendix B</i>	Positive Material Identification Practice
<i>Index</i>	

The front of the volume contains the Foreword and Preamble, which provide a fundamental description of Section I and its application. First-time users of Section I often skip over the Foreword and the Preamble and proceed directly to the body of the book. This is a mistake, because there is a good deal of useful information about Section I, its scope, how the Code works, policy regarding implementations dates for new and revised rules (discussed more in Chapter 2), and definitions of various types of power boilers in this introductory material. Also in the front of the book is a current listing of the personnel of the Boiler and Pressure Vessel Committee, which administers all sections of the Code.

THE PARTS OF SECTION I**Part PG**

Part PG is the first major section of Section I and provides general requirements for all methods of construction. It covers such important topics as scope and service limitations; permitted materials; design; requirements for piping, valves, fittings, feedwater supply, and safety valves; permitted fabrication methods; inspection; hydrostatic testing; and certification by stamping and data reports. The general requirements of Part PG must be used in conjunction with specific requirements given in the remainder of the book for the particular type of construction or type of boiler used. Most Part PG topics are covered in later chapters of this book.

Part PW

The second major section is called Part PW, Requirements for Boilers Fabricated by Welding. Since almost all boilers are now welded, this is a broadly applicable part containing much important information. It covers such topics as responsibility for welding; acceptable weld joint designs; types of welding permitted; postweld heat treatment of welds; radiography, inspection, and repair of welds; and testing of welded test plates. Part PW is described and explained in detail in Chapter 6.

Part PR

With the gradual replacement of riveting by welding, BPV I decided that no purpose was served by continuing to maintain and reprint in each Edition the special rules applicable to riveted construction, Part PR. Accordingly, the 1974 and all subsequent Editions of Section I mandate the use of Part PR rules as last published in the 1971 Edition.

Part PB

The next section, Part PB, Requirements for Boilers Fabricated by Brazing, first appeared in the 1996 Addenda to the 1995 Edition of Section I. Although brazing had long been used in the construction of certain low-pressure boilers, no brazing rules had ever been provided in Section I. Part PB brazing rules resemble Part PW welding rules, but are much less extensive. One notable difference is that the maximum design temperature depends on the brazing filler metal being used and the base metals being joined. Maximum design temperatures for the various brazing filler metals are given in Table PB-1. Brazing procedures and the

performance of brazers must be qualified in accordance with Section IX, by methods similar to those described in Chapter 6 for qualifying weld procedures and welders. The design approach used for determining the strength of brazed joints is given in PB-9: the manufacturer must determine from suitable tests or from experience that the specific brazing filler metal selected can provide a joint of adequate strength at design temperature. The strength of the brazed joint may not be less than that of the base metals being joined. This strength is normally established by the qualification of the brazing procedure. If the manufacturer desires to extend the design temperature range normally permitted by Table PB-1 for the brazing filler metal selected, the manufacturer must conduct two tension tests of production joints, one at design temperature, T , and one at $1.05T$. The joints must not fail in the braze metal. Some acceptable types of brazed joints are illustrated in Fig. PB-15. Nondestructive examination of brazed construction relies primarily on visual examination supplemented by dye penetrant inspection if necessary. PB-49 provides guidance on inspection and any necessary repairs.

The remainder of Section I is composed of parts providing special rules applicable to particular types of boilers or other Section I components, such as feedwater heaters.

Part PWT

Part PWT, Requirements for Watertube Boilers, is a very brief collection of rules for this type of boiler, some of them pertaining to construction details rarely used today. All large high-pressure boilers are watertube boilers. Most construction rules for these boilers are found in Parts PG and PW, and Part PWT is merely a brief supplement. It is, however, the only place where rules for the attachment of tubes to shells and headers of watertube boilers can be found. Part PWT is an example of the retention by Section I of certain old rules and construction details because some manufacturers might still use them.

Part PFT

Part PFT, Requirements for Firetube Boilers, is a much more extensive set of rules, still very much in use for this popular type of boiler, which is quite economical for generating low-pressure steam. Except in special cases, the large-diameter shell places a practical limit on design pressure at about 400 psi, although most firetube boilers have lower pressures. Part PFT covers many variations within the type, in considerable detail. Requirements cover material, design, combustion chambers and furnaces, stayed surfaces, doors and openings, domes, setting, piping, and fittings. Part PFT is the only part of Section I where design for external pressure (on the tubes and on the furnace) is considered.

A good deal of Part PFT dates back to the original 1915 Edition of Section I. However, extensive revisions were made in the 1988 Addenda. A much larger selection of materials was permitted, and allowable stresses for the first time became a function of temperature, as is the case elsewhere in the Code. In addition, the design rules for tubes and circular furnaces under external pressure were made consistent with the latest such rules in Section VIII, from which they were taken. In the mid-1990s, Part PFT was further revised and updated, as more fully described in Chapter 4, under Stayed Surfaces.

Part PFH

Part PFH, Optional Requirements for Feedwater Heater, applies to feedwater heaters that fall within the scope of Section I by virtue of their location in the feedwater piping between the Code-required stop valve and the boiler. Under these circumstances, the heater may be constructed in compliance with the rules in Section VIII, Pressure Vessels, Division 1, for unfired steam boilers. Those rules are stricter in a number of respects than those applicable to ordinary Section VIII vessels, as explained later in this chapter under Use of Section VIII Vessels in a Section I Boiler.

The primary side of the heater must be designed for a higher pressure than the Maximum Allowable Working Pressure (MAWP) of the boiler, per 122.1.3 of ASME B31.1. (Remember, this heater is in the feedwater

piping, and rules for the design of feedwater piping are within the scope of B31.1.) Part PFH also stipulates how the heater is to be stamped and documented.

If a feedwater heater within the scope of Section I is equipped with isolation and bypass valves, there is a possibility that it could be exposed to the full shut-off head of the boiler feed pump. PG-58.3.3 cautions about this and notes that control and interlock systems are permitted in order to prevent excessive pressure. (It is impractical to provide sufficient pressure relief valve capacity in these circumstances.) This is discussed further in Chapter 5, Piping Design.

Part PMB

Part PMB, Requirements for Miniature Boilers, contains special rules for the construction of small boilers that do not exceed certain limits [16-in. (400 mm) inside diameter of shell, 20 ft² (1.9 m²) of heating surface, 5 cubic feet (0.14 m³) gross volume, 100 psi (700 kPa) MAWP]. Because of this relatively small size and low pressure, many requirements normally applicable to power boilers are waived. These have to do with material, material marking, minimum plate thickness, postweld heat treatment and radiography of welds, and feedwater supply. To compensate somewhat for this relaxation of the normal rules, and to provide an extra margin of safety, the hydrostatic test of the miniature boiler pressure vessel must be conducted at a pressure equal to three times the MAWP, although, again, under test parameters less restrictive than normally required. Owing to the reduced risk of brittle fracture of the thinner shell of these boilers, a minimum metal temperature of 60°F (15°C) is permitted during the test provided the shell thickness is not greater than 3/8 in. (10 mm) and constructed of only P-No. 8 or certain P-No. 1 materials.

Part PEB

This part, Requirements for Electric Boilers, was added to Section I in 1976. Up until that time, manufacturers had been building these boilers as Section VIII devices. However, Section VIII had no specific rules for electric boilers and the various openings, valves, and fittings normally mandated by Section I (blowoff, drain, water gage, pressure gage, check valve, etc.). Also, the manufacturers were not formally assuming design responsibility for the boiler.

Part PEB covers electric boilers of the electrode and immersion resistance type only and does not include boilers in which the heat is applied externally by electrical means. The boiler pressure vessel may be either a Section I vessel or may be constructed as an unfired steam boiler under the rules of Section VIII, Division 1. Note that those rules require radiography and postweld heat treatment, as explained later in this chapter under Use of a Section VIII Vessel in a Section I Boiler.

Part PEB is unique from other parts of Section I in a number of ways, but notably because it not only permits the use of austenitic stainless steel in water wetted service, but provides specific rules governing its use. After years of successful use under Code Case 1896, rules were added in 1998 allowing immersion element-type electric boilers to be fabricated of austenitic stainless steel provided a cautionary statement indicating strict water chemistry requirements was clearly marked in a visible location on the boiler. Other rules unique to Part PEB were added in 2005 addressing pressure relief valves installed in other than the vertical position as required by PG-71.2. The rules were added to allow for the unusually limited installation space available when an electric boiler is made an integral component of a larger system such as a medical sterilizer. Provided the boiler meets the size and pressure limitation of PMB-2 and the rules regarding pressure relief valve design and size, nozzle location and discharge orientation, the pressure relief valve may have an angle of deviation from vertical of up to 30 deg.

Under the provisions of Part PEB, a manufacturer can obtain an E stamp, which authorizes the manufacturer to assemble electric boilers (by installing electrodes and trim on a pressure vessel). The manufacturer must obtain the pressure vessel from an appropriate symbol stamp holder. The E stamp holder is limited to assembly methods that do not require welding or brazing. (Electric boilers may, of course, also be constructed

by holders of an S or M stamp.) The E stamp holder becomes the manufacturer of record, who is responsible for the design of the electric boiler. This is stipulated in PEB-8.2.

The Data Report Form P-2A for electric boilers is in two parts, one for the vessel manufacturer and one for the manufacturer responsible for the completed boiler, who may be a holder of an E, S, or M stamp. If the vessel is constructed to the Section VIII, Division 1, rules for unfired steam boilers, it must be stamped with the Code symbol U and documented with a U-1 or U-1A Data Report. In such a case, the Section I master Data Report P-2A must indicate this fact, and the U-1A form must be attached to it.

Electric boilers of the resistance-element type must be equipped with an automatic low-water cutoff, which cuts the power before the surface of the water falls below the visible part of the gage glass. Such a cutoff is not required for electrode-type boilers (which use the water as a conductor), since these, in effect, cut themselves off when the water level falls too low.

Part PVG

This part provides rules for organic fluid vaporizers, which are boiler-like devices that use vaporized organic fluid (such as Dowtherm™) instead of steam as the working fluid. The principal advantage of these organic fluids is that they have much lower vapor pressures than water at a given temperature. Thus, they are particularly suitable for heating in industrial processes requiring high temperatures at low pressure. On the other hand, these liquids are flammable, and toxic, and Part PVG contains a number of special provisions because of these drawbacks.

In order to prevent the uncontrolled discharge of organic fluid or vapor to the atmosphere, the use of gage cocks is prohibited. Pressure relief valves must be of a totally enclosed type that will discharge into a pipe designed to carry all vapors to a safe point of discharge. The pressure relief valve lifting lever normally required on Section I pressure relief valves is prohibited, and valve body drains are not mandatory. Because the polymerization of organic fluids can lead to clogging or otherwise adversely affect the operation of pressure relief valves (and because the valves have no lifting levers by which they can be periodically tested), PVG-12.2 requires the removal and inspection of these valves at least yearly. This is a rare instance of the Code reaching beyond its normal new-construction-only coverage.

As a further means of reducing unintentional discharge of organic fluid to the environment by leakage through pressure relief valves, and to prevent the gumming up of these valves, Section I permits installation of rupture disks under the valves. This is the only use of such disks permitted by Section I. Special rules are also provided for calculating pressure relief valve capacity. The required capacity of these valves is based on the heat of combustion of the fuel and the latent heat of the organic fluid. This capacity is determined by the manufacturer.

Part PHRSG

Included in the 2007 Addenda, this part, Requirements for Heat Recovery Steam Generators, is, at this writing, the most recent part to be added to Section I. The part was adopted on the recommendation of a BPV I task group formed by then BPV I Chairman, John MacKay. Charged with determining the best methodology to address Code rules for HRSG devices, it was the task group's opinion that a distinct Section I part was the best approach. This part addresses rules for a unique type of boiler in that the HRSG is typically a highly cycled peaking unit used by utilities and industrial owners to generate "on demand" steam. By definition, an HRSG has as its principal source of heat, a gas stream having high temperatures and ramp rates, both up and down, such as from a combustion or gas turbine. As described in PHRSG-2, the HRSG may have one or more superheaters, reheaters, evaporators, economizers, and feedwater heaters, all within the gas path, and none of which can be isolated from the gas stream. The typically fast start-up and shut down requirements imposed upon the HRSG, as well as the National Fire Protection Association (NFPA) regulations relating to combustion turbines, pose design and operating problems not found with more conventional power boil-

ers. Issues include superheater and reheater condensate, desuperheater operation, economizer pressure relief devices, and steam drum design.

Early data from operating experience of what was then referred to as “waste heat recovery boilers” indicated that spring-loaded economizer pressure relief valves often chattered due to poor performance when relieving water pressure. The overpressure was caused primarily by the feedwater pump and was particularly prevalent during the frequent start-ups of peaking units, often leading to valve damage. This problem was mitigated by Code Case 2446, Pilot-Operated Pressure Relief Valves for PG-67.2.6 Applications. Issued in 2004, one might consider this case one of the first major steps toward development of rules specifically addressing HRSG. Another step toward development of Part PHRSG was the approval in July, 2006, of Code Case 2485, Steam Drum in Heat Recovery Steam Generator System. This permitted the use of steam drums in HRSG that were designed to Section VIII, Division 2 rules. These drums are thinner and allow faster and more frequent start-ups without the problems caused by onerous through-wall thermal gradients found in thicker Section I designed drums.

Because of the high cycling rate often associated with HRSG, the boiler is often shutdown, closed up hot, and then restarted with substantial pressure still on the boiler. Also, NFPA rules relating to combustion turbines require that the hot gas stream be purged to insure that unspent fuel is evacuated from the boiler. This purging causes a substantial amount of condensate to form in the superheater and reheater coils. Unlike a conventional boiler that eliminates condensate during a slower start-up phase referred to as “boil out” (see Chapter 5), the high temperatures and ramp up rate of an HRSG requires a fast removal of the condensate prior to establishing steam flow. Owing to the unique operating parameters of an HRSG, condensate can also form during actual operation of the unit. To address these unique conditions, PHRSG-3 provides rules requiring that each superheater and reheater be equipped with an automatic condensate detection device and with connections capable of being opened under pressure. The rules also exempt the connections from the blowoff size limitations of PG-59.3.5 and allow the connections to serve as the drain connections required by PG-59.4. As discussed in more detail in Chapter 5, traditional blowoff systems require two valves, one of which must be a slow-opening valve. Because of the importance of fast condensate removal, the rules in PHRSG-3 require that all condensate removal piping have two quick-opening-type valves. The piping must be routed to a blowdown tank, flash tank, manifold, or other collection device.

Unique operating conditions of HRSG also impact desuperheater operation. HRSG are often arranged so that the steam from more than one HRSG feeds a common steam turbine. This arrangement allows one or more HRSG to be taken off-line when there is a reduced power demand. When one or more HRSG is off-line, there is reduced back pressure in the steam turbine resulting in lower operating pressure in the HRSG. This sliding pressure operation, together with the high cycling nature of the HRSG, results in a broad control range for desuperheaters, also referred to as attemperators. Improper control of the desuperheater can result in unvaporized spray water in the piping and HRSG leading to a variety of problems. To address this, PHRSG-4 provides requirements for locating drain pots, with automatic detection and operation, near the desuperheaters.

THE APPENDICES

Mandatory

Mandatory Appendix I	Submittal of Technical Inquiries to The Boiler and Pressure Vessel Committee
Mandatory Appendix II	Standard Units for Use In Equations
Mandatory Appendix III	Criteria for Reapplication of An ASME Code Symbol Stamp
Mandatory Appendix IV	Local Thin Areas in Cylindrical Shells and Spherical Segments of Heads

Non-Mandatory

Non-Mandatory Appendix A Explanation Of The Code Containing Matter Not Mandatory Unless Specifically Referred To In The Rules of the Code This appendix contains a great deal of miscellaneous information, some of it dating from the first Edition. Most of this explanatory material remains nonmandatory, but some are specifically referred to in the main body of Section I and, therefore, mandatory. Examples of these referenced appendices include Quality Control System (A-300), Acceptance of Testing Laboratories and Authorized Observers for Capacity Certification of Pressure Relief Valves (A-310), Methods for Magnetic Particle Examination (MT) (A-260), and Methods For Liquid Penetrant Examination (PT) (A-270). Another, Cylindrical Components Under Internal Pressure (A-317), is deserving of mention for two reasons. One, it is referenced in PG-27 as an *alternative* to the formula required by that paragraph for determining the MAWP of piping, tubes, drums, and headers. Two, it is often referred to as “The Fishburn Formula” in respect for the greatly admired colleague, John Fishburn, who developed the formula described in the appendix. While some long overdue housecleaning has removed material in Appendix A considered obsolete or redundant, the diversity of the remaining subjects can be seen from this partial list of contents:

- Braced and Stayed Surfaces
- Method of Checking Safety-Valve Capacity by Measuring Maximum Amount of Fuel That Can Be Burned
- Automatic Water Gages
- Fusible Plugs
- Proof Tests to Establish Maximum Allowable Working Pressure
- Suggested Rules Covering Existing Installations:
 - Pressure Relief Valves for Power Boilers
 - Repairs to Existing Boilers
- Examples of Methods of Computation of Openings in Vessel Shells
- Examples of Computation of Allowable Loadings on Structural Attachments to Tubes
- Preheating
- Maximum Allowable Working Pressure — Thick Shells
- Rounded Indication Charts
- Data Report Forms and Guides
- Codes, Standards, and Specifications Referenced in Text (The dates of the currently approved Editions are listed in this location only, rather than throughout Section I.)
- Guide to Information Appearing on Certificate of Authorization
- Sample Calculations for External Pressure Design

Non-Mandatory Appendix B Positive Material Identification Practice This appendix provides a guide for the Manufacturer when developing a Positive Material Identification Practice (PMIP) when considered appropriate.

INTERPRETATIONS

Since 1977, the ASME has published all the replies from the ASME staff on behalf of the ASME Boiler and Pressure Vessel Standards Committees to inquiries on the interpretation of Section I (and also the other book sections). These interpretations are issued with each Addenda along with a cumulative index by subject and paragraph number. Many Section I users find it convenient to bind the interpretations in the back of the book, for easy reference. While many Code users still consider interpretations as the equivalent of Code rules, this

position has become much less prevalent, particularly among knowledgeable users and Authorized Inspectors. Despite the fact that interpretations are said not to be a part of the Code, they can be very useful in explaining its application and in resolving disputes as to what the Code intends. Many interpretations are quoted throughout this book to explain various provisions of Section I. Further discussion about interpretations, their official status, and how BPV I formulates them is found in Appendix II, under Committee Operations.

An example of the designation of a Section I Interpretation is I-95-27. The I signifies that the interpretation pertains to the rules of Section I; the 95 indicates that it is an interpretation of the 1995 Edition of Section I; and the 27 means that it is the 27th published interpretation of that Edition. Before 1983, the year of the interpretation referred to the year it was issued rather than the Edition of Section I to which it pertained. For example, Interpretation I-81-26 was the 26th interpretation issued in 1981. Throughout this book, interpretations are designated in this same fashion. One means of finding an interpretation on a particular subject is to find that subject in the general index and then go to the chapter on that subject. Also, a numerical index of all interpretations mentioned in this book, with key words and abstracts, has been provided to help in finding any desired interpretation.

PRESSURE RANGE OF SECTION I BOILERS

As explained in the Preamble, Section I covers boilers in which steam or other vapor is generated at a pressure of more than 15 psi (100 kPa) for use external to the boiler (all pressures used in Section I are gage pressure). For high-temperature water boilers, Section I applies if either the pressure exceeds 160 psi (1.1 MPa) or the temperature exceeds 250°F (120°C). Since the vapor pressure of water at 250°F (120°C) is approximately 15 psi (100 kPa), the two lower limits of coverage are related. Boilers designed for pressures below 15 psi (100 kPa) are usually constructed to the rules of Section IV, Heating Boilers. However, such units could be built, certified, and stamped as Section I boilers if all the requirements of Section I were met. Section I has no upper limit on boiler design pressure.

FIRE VERSUS UNFIRED BOILERS

Section I rules are intended primarily for fired steam or hot water boilers and organic fluid vaporizers. There are, however, boilers called unfired steam boilers that do not derive their heat from direct firing. These unfired steam boilers may be constructed under the provisions of either Section I or Section VIII, Rules for Construction of Pressure Vessels. The definition of an unfired steam boiler is not as clear as it might be, which has led to some confusion and occasional disagreement between BPV I and BPV VIII. The Preamble to Section I states that:

A pressure vessel in which steam is generated by the application of heat resulting from the combustion of fuel (solid, liquid, or gaseous) shall be classed as a fired steam boiler.

Unfired pressure vessels in which steam is generated shall be classed as unfired steam boilers with the following exceptions:

- (a) vessels known as evaporators or heat exchangers;*
- (b) vessels in which steam is generated by the use of heat resulting from operation of a processing system containing a number of pressure vessels such as used in the manufacture of chemical and petroleum products.*

It is these exceptions that cause the confusion, for several reasons. It is sometimes not apparent whether a boiler using waste heat is fired or unfired. It may also be difficult to distinguish between an unfired steam boiler using waste heat and certain heat exchangers also using waste heat. Another difficulty arises from the source of the waste heat; is it from the combustion of fuel? If so, the device is generally considered fired. However, some jurisdictions have permitted boilers using waste heat from a combustion turbine to be

considered unfired. The presence of auxiliary burners in a boiler using waste heat from another source would cause that boiler to be considered fired. This was affirmed in Interpretation I-92-20. Remember also that all ASME Code sections routinely caution users that laws or regulations at the point of installation may dictate which Code section applies to a particular device and that those regulations may be different from or more restrictive than Code rules. The jurisdictions may also have rules that define whether a device is considered a boiler or a heat exchanger and whether it is considered fired or unfired.

Electric boilers can be considered fired or unfired, depending on the circumstances. An inquiry on this subject was answered by Interpretation I-81-01, as follows:

Question: The Preamble of Section I defines an electric boiler as “a power boiler or a high-temperature water boiler in which the source of heat is electricity.” Would you define whether or not an electric boiler is considered to be a fired or an unfired steam boiler?

Reply: PEB-2 provides criteria for determining if an electric boiler is considered to be a fired or an unfired steam boiler.

An electric boiler where heat is applied to the boiler pressure vessel externally by electric heating elements, induction coils, or other electrical means is considered to be a fired steam boiler.

An electric boiler where the medium (water) is directly heated by the energy source (electrode type or immersion element type) is considered to be an unfired steam boiler.

An unfired steam boiler constructed to Section VIII must meet rules more stringent than run-of-the-mill Section VIII vessels. For example, these rules require additional radiographic examination, postweld heat treatment, and possibly impact testing of materials and welds, as more fully described under the next topic, The Use of Section VIII Vessels in a Section I Boiler.

Some owners of steam-generating vessels would prefer, if possible, to avoid the classification of boiler, or fired boiler, because most states and provinces require an annual shutdown for inspection of boilers, although some states permit longer periods of operation. The interval between inspections mandated for Section VIII vessels is typically much longer, permitting longer uninterrupted use of the equipment in question.

One of the distinctions some committee members perceive between fired and unfired boilers is whether a flame from a poorly adjusted burner can impinge directly on pressure parts and overheat them. This is clearly a possibility in a fired boiler, and it is one reason for some of the conservatism of Section I rules, and for requiring annual outages for inspection. By contrast, hot gases from some upstream source are less likely to cause overheating of those same pressure parts because they are less likely to be misdirected, and presumably, no actual flames can reach the downstream steam-generating pressure parts.

A question was once asked as to whether the determination of fired service (versus unfired) involves the transfer of heat by all three means — radiation, convection, and conduction — or whether fired service is defined simply as the transfer of heat resulting from combustion no matter where or how it takes place. Unfortunately, Section I provides no criteria by which such a distinction could be made, and it is unlikely that BPV I could formulate such criteria. It is possible that the committee could be persuaded that a boiler heated by gases below some temperature could be considered an unfired boiler. Just what temperature that might be [850°F (455°C), 700°F (370°C)?] is a matter of conjecture. Such an idea might be tried as a Code Case, but, so far, no one has requested such a case.

THE USE OF SECTION VIII VESSELS IN A SECTION I BOILER

Usually all parts of a Section I boiler are constructed to Section I rules. There are a few exceptions worth noting. Vessels used as the pressure vessels for electric boilers (see PEB-3), the drums or other parts of unfired steam boilers (see Code Case 1855), steam drums for a heat recovery steam generator system (see Code Case 2485), and feedwater heaters that fall under Section I jurisdiction by virtue of their location in the feedwater piping (see PFH-1.1) are among those that may be constructed to Section VIII under that section’s special rules for unfired steam boilers in UW-2(c). One other type of Section VIII vessel that can be used in a Sec-

tion I boiler is mentioned in the next-to-last paragraph of the Preamble. That vessel is an expansion tank used in connection with what is defined in footnote 4 to the Preamble as a high-temperature water boiler. This is the only mention of such tanks in Section I, and nothing is said about their construction having to meet the special Section VIII requirements for unfired steam boilers. Thus, it seems that an ordinary Section VIII vessel would serve the purpose.

Although it might seem that components built to Section VIII are just as safe as those built to Section I and that therefore they should be virtually interchangeable, this is unfortunately not the case. When Section I does permit the use of Section VIII vessels, it insists on invoking certain special rules within the applicable Code Case or other Section VIII rules for unfired steam boilers. These Section VIII rules are a little more stringent than those for other Section VIII vessels. The rules are found in U-1(g), UG-16(b)(3), UG-125(b), and UW-2(c) of Section VIII, Division 1. The most important requirements called out in these several paragraphs are the following:

- Pressure relief valves are to be furnished in accordance with the requirements of Section I insofar as they are applicable.
- For design pressures exceeding 50 psi (345 kPa), radiography of all butt-welded joints is required, except for circumferential welds that meet the size and thickness exemptions of UW-11(a)(4). [Those exemptions cover welds in nozzles that are neither greater than NPS 10 (DN 250) nor thicker than 1½ in. (29 mm).]
- Postweld heat treatment is required for vessels constructed of carbon and low alloy steel.
- A minimum thickness of ¼ in. (6 mm) is required for shells and heads, exclusive of any corrosion allowance.

Another extra requirement imposed on an unfired steam boiler constructed to Section VIII, Division 1 rules applies to all Section VIII vessels made of carbon and low alloy steels. The designer must establish a Minimum Design Metal Temperature (MDMT), the lowest temperature expected in service at which a specified design pressure may be applied. Unless the combination of material and thickness used is exempt by the curves of UCS-66 at the MDMT, impact testing of the material is required, and the Weld Procedure Qualification would also have to include impact testing of welds and heat-affected zones. This is not explicitly mentioned in the paragraphs dealing with unfired steam boilers because it is a requirement that was added to Section VIII, Division 1 in the mid-1980s, long after those other paragraphs were written, and probably because BPV VIII members assumed that everyone knows that impact testing is routinely required unless the vessel materials meet certain exemptions provided in UCS-66.

What is also notable about these rules for unfired steam boilers is the fact that the ordinary Section VIII exemptions for postweld heat treatment (PWHT) are not available, even for welds in relatively thin P-No. 1 materials. Moreover, the Section I Table PW-11 exemption from radiography of circumferential butt welds in steam-containing parts up to NPS 16 (DN 400) or 1 5/8 in. (41 mm) wall thickness is also not available.

An example of the consequences of overlooking these somewhat obscure rules occurred recently when a boiler manufacturer placed an order for a sweetwater condenser with a manufacturer of Section VIII pressure vessels without specifying that the condenser, as a type of feedwater heater, had to meet the UW-2(c) rules for unfired steam boilers. (A sweetwater condenser is a shell and tube heat exchanger connected directly to the boiler drum that receives saturated steam from the drum on the shell side and has feedwater going to the drum inside the tubes. The steam condenses on the tubes, giving up its heat to the feedwater and providing a supply of water pure enough to use as spray water in the superheater. These condensers are used where the regular feedwater supply is not of sufficient quality to use as spray water.).

After the condenser was installed and the boiler was ready for the hydrostatic test, the Authorized Inspector (AI) inquired about the presence of a Section VIII vessel in a Section I boiler. He was told that it was a feedwater heater furnished to the rules of Part PFH of Section I. The AI reviewed those rules and asked about the required radiography and postweld heat treatment, which it turned out had not been done because the boiler manufacturer had ordered the condenser as an ordinary Section VIII vessel. The condenser had to be cut out of the installation, shipped back to the manufacturer, radiographed, and given a postweld heat

treatment. This PWHT had to be conducted very slowly and carefully, using thermocouples during heating and cooling to avoid too great a temperature difference between shell and tubes, which could cause excessive loading on the tubes, tube welds, or tubesheet. Fortunately, the radiography and PWHT were quickly and successfully accomplished, and the condenser was reinstalled in the boiler with minimal delay.

Three circumstances have been mentioned in which Section VIII vessels can be used as part of a Section I boiler: feedwater heaters under Part PFH; pressure vessels for electric boilers covered under Part PEB; and as a “Section VIII Unfired Steam Boiler in a Section I System,” covered under the provisions of Code Case 1855. The title of Case 1855 is a little confusing, as is the case itself. Its ostensible purpose is to permit the inclusion in a Section I boiler of parts built to Section VIII and construed to be components of an unfired steam boiler. Case 1855 was originally developed for application to waste heat boilers in petroleum refineries, which use one or more drums and one or more arrays of heat-exchange surface to generate steam. Case 1855 permits what might be called a hybrid Section I boiler, with some portions built to Section VIII. The separate portions must be stamped and documented as called for by the respective sections. To aid in recording all the items, the Form P-5, Summary Data Report For Process Steam Generators, may be used by the Manufacturer as described in PG-112.2.6. When used, the form must be attached to the Manufacturer’s Data Report.

STANDARDS REFERENCED BY SECTION I

Users of Section I soon realize that it is not a stand-alone volume; it depends to a considerable extent on other sections of the Code and on certain other standards. In the development of the Code, it was recognized that there was no need to duplicate already available and acceptable standards used in the industry. Section I, like most other product codes, reviews and adopts material, product, and testing standards developed by other standards groups. This process makes use of the expertise available from organizations that specialize in these other areas.

For example, standard pressure parts such as fittings, flanges, and valves are accepted by reference to the ASME product standards listed in PG-42. (See also Standard Pressure Parts, in Chapter 11.) Another example is nondestructive examination, where PW-51 and PW-52 refer to Section V, Article 2 for radiographic examination and Article 4 for ultrasonic examination. To obtain quality castings, PG-25 invokes Section V, Article 7 for magnetic particle examination. Within Section V, mention is made also of ASTM E-125-63 for reference photographs to determine which defects must be removed. PW-50 requires personnel performing and evaluating radiographic examinations to be qualified and certified in accordance with a written practice developed using either SNT-TC-1A, *Recommended Practice for Nondestructive Testing Personnel Qualification and Certification*, or CP-189, *ASNT Standard for Qualification and Certification of Nondestructive Testing Personnel*. Both documents are published by the American Society for Nondestructive Testing. (See further discussion in Chapter 7, under Qualification and Certification of NDE Personnel).

An indispensable code for use in conjunction with Section I is ASME B31.1, Power Piping, which in 1972 was assigned the rules for material, design, fabrication, installation, and testing of that part of the boiler known as boiler external piping. (See discussion in Chapter 4.) This transfer came about when BPV I decided that certain rules were needed for the flexibility analysis of this piping, which extends beyond the boiler setting. After recognizing the magnitude of the task of developing its own rules, BPV I somewhat reluctantly agreed that this piping could henceforth be covered by B31.1, which already had the necessary rules. Accordingly, a number of Section I paragraphs dealing with what is now called boiler external piping were transferred to B31.1 by the Summer 1972 Addenda of Section I and the B31.1d Addenda to B31.1 and were issued on the same date.

As explained in the discussion of fired versus unfired boilers earlier in this chapter, Sections I and VIII both have rules for unfired steam boilers, and both sections refer to each other’s rules. Section VIII vessels may also be used in electric boilers, under the provisions of Part PEB (see description of Part PEB in Organization of Section I, above).

It is a policy of the BPV Standards Committees to strive for consistency in the rules of the various book sections, while recognizing the wide differences in the construction rules suitable for such diverse components as heating boilers and nuclear vessels. Accordingly, the various sections typically use the same reference standards for such activities as nondestructive examination and welding.

Specific (dated) editions of standards referenced in Section I are grouped together in one table, in Appendix A-360. This avoids having to revise the date at every mention of the standard throughout the text each time a later edition of the standard is adopted.

HOW AND WHERE SECTION I IS ENFORCED AND EFFECTIVE DATES

UNITED STATES AND CANADA

Section I is a set of rules for the construction of boilers. These rules are not mandatory unless invoked by contract or adopted as law by a governmental entity, usually referred to as a jurisdiction. A jurisdiction can be a state, province, county, or city. If there happen to be no jurisdictional requirements regarding Code coverage, the purchaser of a boiler may specify to the manufacturer construction to Section I rules as a requirement.

Currently, Section I has been adopted by all but one state (Wyoming is the exception) and by all of the provinces of Canada. Wyoming has a pressure vessel law, but has not enacted a boiler law nor developed boiler rules and regulations. Because of Wyoming's relatively sparse population and limited industrial facilities, the legislature apparently does not consider the expense of implementing the law to be justified, since as a practical matter, all boilers in the state probably meet the ASME Code. Seventeen cities, counties and territories also have laws requiring Section I construction (see Fig. 2.1, which is a map of the jurisdictions with boiler and pressure vessel laws).

States and provinces with boiler laws typically enforce the Code by means of an appointed board or commission that writes and revises boiler rules and an appointed chief inspector with the necessary enforcement staff. The jurisdictional authorities also depend on the efforts of Authorized Inspectors working for Authorized Inspection Agencies, whose function is to assure that the boiler manufacturer has complied with Section I. (See Chapter 8: Third Party Inspection.) These same jurisdictional authorities also have the responsibility for overseeing the care and operation of boilers once they are completed.

In 1997, because of international trade agreements that require removal of nontechnical barriers to trade, the situation in which most states and provinces required boilers and pressure vessels installed within their jurisdictions to meet the ASME Code began to change. At that time, the National Board of Boiler and Pressure Vessel Inspectors (a regulatory agency comprised of the chief inspectors of states in the United States and provinces of Canada — see description and discussion in Chapter 16) changed its policy regarding equipment that could be registered with the National Board. The National Board



FIG. 2.1
MAP OF STATES AND PROVINCES WITH BOILER AND PRESSURE VESSEL LAWS
(COURTESY OF THE NATIONAL BOARD SYNOPSIS OF BOILER AND PRESSURE VESSEL
LAWS, RULES AND REGULATIONS)

now permits registration of boilers and pressure vessels manufactured to codes of construction other than the ASME Code provided the code of construction has been accepted by the National Board, the manufacturing organization has implemented a quality system, and the manufacturing organization has provided for third party inspection. At this writing, two codes governing boiler construction have been accepted by the National Board; the ASME Code and the Canadian Standards Association Code CSA-B51. For more detailed information regarding boiler registration with the National Board, see National Board documents NB-370, *National Board Synopsis of Boiler and Pressure Vessel Laws, Rules and Regulations*, and NB-264, *Criteria for Registration of Boilers, Pressure Vessels and Pressure Retaining Items*.

INTERNATIONAL ACCEPTANCE

Section I is recognized internationally as an acceptable design code, along with other national codes such as the German Technical Regulations for Boilers (TRD) and the Japanese Industrial Standards (JIS). At one time, the Mexican mechanical engineering society AMIME translated Section I into Spanish for use in Mexico, but it was apparently little used, in part due to the difficulty of keeping up with the ongoing changes in Section I. Before the 1970s, the ASME allowed only U.S. and Canadian companies to engage in ASME Code construction. However, as a result of legal action at that time, the ASME has been under specific instructions from a consent decree requiring cooperation with non-U.S. or Canadian manufacturers to allow their certification as authorized ASME Code symbol stamp holders. As a result of this and the influence of the North American Free Trade Agreement (NAFTA) and the World Trade Organization [WTO — formerly General Agreement on Tariffs and Trade (GATT)], the ASME has been active in seeking acceptance of its code by the international community. There are now more than 2500 non-U.S. or Canadian manufacturers who are ASME Code symbol stamp holders that can engage in Code construction of boilers and pressure vessels.

For field-assembled boilers (those too large to be completed in the shop), full compliance with the ASME Code requires that field assembly be accomplished by appropriate Code symbol stamp holders and also that an Authorized Inspection Agency provide the necessary field inspection. Foreign jurisdictions other than Canada do not generally insist on full compliance with the ASME Code. Since foreign purchasers want to reduce costs, they often accept so-called ASME boilers that have not been field assembled by appropriate ASME Code symbol stamp holders under the surveillance of an Authorized Inspector. Consequently, although the components of such boilers may have been designed and manufactured in accordance with Section I, the completed boilers do not meet all the requirements that would permit full Code stamping and certification. See further discussion at the end of Chapter 9.

UNIFORM BOILER AND PRESSURE VESSEL LAWS SOCIETY

To provide the advantages of uniformity of construction and inspection, the Uniform Boiler and Pressure Vessel Laws Society, Inc. was founded in 1915, just 3 months following the official adoption of the first ASME Boiler Code. This society provided model legislation to jurisdictions and supported nationally accepted codes, such as Sections I and VIII, as standards for the construction of boilers and pressure vessels. In general, the society encouraged adoption of uniform requirements by the jurisdictional authorities. Manufacturers strongly supported this effort because it promoted the manufacture of economical standard products and obviated custom-designed features for different jurisdictions.

Now that most states have boiler and pressure vessel laws, the original mandate of the Uniform Boiler and Pressure Vessels Laws Society has been fulfilled, and the Society has been disbanded. Efforts are now being carried on by members of the National Board to address new challenges posed by international trade and the use of various international standards for construction of boilers and pressure vessels.

NATIONAL BOARD INSPECTION CODE

Section I covers only new construction, and once all of its requirements for a new boiler have been met and the necessary data reports have been signed, Section I no longer applies. In jurisdictions that have adopted the National Board Inspection Code (NBIC), that code is applicable for installation, inspection, repair, or alteration of pressure-retaining items. See further discussion in Chapter 16, Rules Covering Boilers in Service.

EFFECTIVE DATES OF THE CODE AND CODE REVISIONS

Because the Code is in a continual state of evolution, to apply it properly, the user must understand the effective dates of the Code Edition and subsequent Addenda. The Addenda contain additions and revisions to Code rules that have been approved by the Committee since issuance of the last Code Edition. The words traditionally accepted as “rules” for establishing the effective (mandatory) dates of Section I rules are found in the Foreword of the Code. These say:

After Code revisions are approved by ASME, they may be used beginning with the date of issuance. Revisions, except for revisions to material specifications in Section II, Parts A and B, become mandatory six months after such date of issuance, except for boilers or pressure vessels contracted for prior to the end of the six-month period. (Note: The Foreword goes on to explain the treatment of revisions to material specifications and this is also covered later in this Chapter.)

The ASME used to issue Addenda every 6 months (as Summer and Winter Addenda) when, in 1986, it was decided for reasons of economy that only one set of Addenda per year would suffice. The Addenda were then issued December 31 to be effective on July 1 of the succeeding year. For example, the first Addenda to the 1989 Code were simply called the 1989 Addenda, A89. All successive Addenda were then identified in similar fashion by year only. Each Code Edition eventually had three sets of Addenda, issued on different colored pages to help keep track of which came first. Purchasers of any section of the Code receive the Addenda for the next 3 years. Thus, a purchaser of the 1995 Edition of Section I would have eventually received the 1995, 1996, and 1997 Addenda.

In 1997, the ASME changed the system once again. Starting in 1998, the ASME began issuing the Addenda on July 1 of each year rather than December 31. In years between Editions, the Addenda continued to be issued on colored pages with one exception: the 1998 Edition contained the changes approved for the 1998 Addenda. Going forward, new Editions (i.e., 2001, 2004, 2007) contain white pages comprising the rules of the previous Edition with its three sets of Addenda incorporated and the first Addenda to the new Edition. Revisions are identified and a description of each change provided. If this seems a bit confusing now, it was more so in 1998. Users familiar with making reference to Code rules by Edition and Addenda (e.g., 1995, A97) were in a quandary as to how to reference the rules contained in the 1998 Edition. This eventually resulted in Interpretation I-01-08 being issued in June, 2001, to mitigate the confusion.

Question (1): The 1998 Code Edition, as published, incorporates the 1998 Addenda. When providing reference to this Code Edition and Addenda within a Code-required document, may only the Edition be listed (i.e., 1998 Edition)?

Reply (1): Yes.

Question (2): For the 1998 Edition only, is it necessary to revise the Code-required documentation where the term “1998 Edition” was used as meaning the 1995 Edition through the 1997 Addenda?

Reply (2): No.

This interpretation clarified that going forward, manufacturers not intending to apply the rules of the first Addenda of a new Edition should reference the previous Edition with its last Addenda (e.g., 2001, A03) instead of the new Edition (e.g., 2004).

As noted earlier in this chapter, the Foreword of the Code has been interpreted as requiring that revisions (Addenda) become mandatory 6 months after the date of issue, except for boilers contracted for prior to the end of the 6-month period. In effect, this gives a manufacturer a 6-month grace period during which any Code changes affecting new contracts are optional. Note that the key date is the contract date. This can be a formal contract, a letter of intent, or other legally accepted contractual date. It would be reasonable to think that such a straightforward rule would be easily applied, but as is often the case, real-life circumstances turn the simple into the complex. This was demonstrated as early as 1978 by requests for interpretations relating to establishing effective Code rules. The Committee was asked about the governing Code rules for boiler external piping contracted for long after the boiler. This was addressed in Interpretation I-78-13, Applicable Code Edition for Boiler External Piping:

Question: When boiler external piping is contracted for later than the boiler is, to what rules is the boiler external piping to be built?

Reply: Boiler external piping is a part of the boiler and, as such, the applicable Code Editions are those which correspond to the contract date for the boiler. However, when contracts for boiler external piping are placed later than the boiler contract date, the parties have the option of using Section I as of the boiler contract date or any subsequent Addenda of Section I.

The Edition and Addenda of B31.1 to which the boiler external piping is ordinarily to be constructed (unless a later version is selected) is found in the appendix of Section I in Table A-360: Codes, Standards, and Specifications Referenced in Text. Again, in 1984, a question was raised about use of parts manufactured to earlier Code rules than those in effect when the parts were selected. This was addressed by Interpretation I-83-93, Use of Parts Manufactured to Superseded Revisions:

Question (1): May parts for Section I or Sections VIII vessels, made prior to the mandatory use date of the Code to which the boiler or pressure vessel is to be constructed, be used provided they meet the requirements of the applicable Code Edition and Addenda and are established by the certificate holder to be suitable for the design conditions?

Reply (1): Yes.

Question (2): Is any special documentation required for such parts?

Reply (2): No.

Later, in 2001, a question was raised regarding certification to earlier Editions and Addenda. This prompted issuance of Interpretation I-01-13, Code Certification to Earlier Editions and Addenda of the Code:

Question: A boiler part is ordered or “contracted for” at a time when the Code Edition and Addenda in effect is later than the Edition and Addenda governing the manufacture of the boiler. May the part be manufactured to, and may the part Manufacturer, using the latest version of the appropriate Manufacturer’s Data Report, certify compliance with the same Code Edition and Addenda that govern the manufacture of the boiler?

Reply: Yes.

One can imagine that many similar questions never made it to the Committee but, rather, were resolved in some fashion by mutual agreement between the manufacturer, the owner, the Authorized Inspector, and the jurisdictional authorities. It is also easy to understand why some would think that the interpretations noted above were examples of “writing rules by interpretation,” a growing concern to ASME.

Before explaining the actions planned by the ASME to resolve these and similar issues, it is necessary to digress a bit to explain why the earlier use of the word “rule” was placed in quotation marks when used in context with the Foreword of the Code. The ASME Boiler and Pressure Vessel Code is an American National Standards Institute (ANSI) standard. To be accepted as an ANSI standard, the process of writing and issuing Code rules must adhere to ANSI-approved procedures. These procedures require, among other things, that proposed changes be made available for public review and comment prior to being issued. As it turns out, the Foreword is not part of this process and, therefore, is not considered part of the Code. That is why,

technically, the Foreword, while traditionally accepted as containing rules, only provides guidance and clarifications regarding the Code. The same reasoning can be applied to interpretations, thus the concern about “writing rules by interpretation.” With that brief explanation in mind, what is ASME in the process of doing to provide much needed rules for establishing the effective Code Edition and Addenda?

The issues noted above, particularly that of certifying parts to earlier Editions of the Code, prompted the Board of Conformity Assessment to form, in January, 2007, a task group to determine the best way for all non-nuclear Codes (i.e., Sections I, IV, VIII, X, and XII) to establish rules regarding effective Code dates. The Board of Conformity Assessment has, among other things, oversight responsibility for protection of the ASME mark (e.g., Code symbols stamps). If, indeed, it was mandatory that rules be applied 6 months after issuance, then following the guidance provided by the noted interpretations might be considered misuse of the mark and, therefore, put the ASME’s control of its mark in jeopardy. After lengthy and in-depth consideration of the issues, the task group concluded that it was best that each Code develop its own specific rules for establishing effective Code requirements. Instead of proposing specific rules for each Code, the task group proposed a revision to an existing ASME Codes and Standards policy (CSP-9). The following was adopted in March, 2008.

CSP-9(c)(3) Every ASME standard that requires use of a certification mark shall have provisions for establishing the effective edition and addenda to be used to construct an item, including a replacement part, that is to be stamped with an ASME certification mark (e.g., Code Symbol Stamp). Such provisions are to address materials, design, fabrication, examination, inspection, testing, overpressure protection, and certification as determined appropriate by the standard committee.

The approval of this policy triggered the establishment of a task group reporting to the Technical Oversight Management Committee (TOMC — see Appendix II) and charged with developing rules for establishing effective Code rules for each of the non-nuclear Boiler and Pressure Vessel Codes.

Established in 2009, the task group was made up of representatives from each of the affected Code sections (Sections I, IV, VIII, X, and XII) as well as the Committee of Boiler and Pressure Vessel Conformity Assessment. The task group quickly concluded that, rather than developing rules for the text of each Code section, it would be best if a mandatory appendix was developed and adopted by each Code. At this writing, the task group has made recommendations to BPV I, anticipating that, if approved, the recommendations would serve as a template for the other Code sections to use in establishing similar rules. The recommendations before BPV I for consideration are:

General

After Code revisions are approved by ASME, they may be used beginning with the date of issuance shown on the Code. Except as noted below, revisions become mandatory six months after the date of issuance. Code Cases are permissible and may be used beginning with the date of approval by ASME. Only Code Cases that are specifically identified as being applicable to this Section may be used. At the time a Code Case is selected, only the latest issue may be used. Code Cases that have been incorporated into this Section or have been annulled may not be used.

Changes to the Code and Code Cases related to design, material, fabrication, examination, inspection, testing, over pressure protection and field assembly made prior to completion of the boiler or replacement part may be critical to the intended service conditions of the boiler. These changes must be considered by the Manufacturer. Application of such changes shall be a matter of agreement between the Manufacturer and the user.

As used in this Appendix, the term “Authorized Inspector” shall be considered to include “Qualified Inspector” and “Certified Individual”.

The wording regarding when revisions become mandatory and when Code Cases may be used is generally the same as those presently in the Foreword.

Design

The Manufacturer of the completed boiler (see PG-104) shall establish the Code Edition, Addenda and Code Cases to be used for design of a boiler, including parts thereof, or a replacement part to be stamped with the ASME certification mark required by this Section.

- a. Except as provided in b and c, the Code Edition and Addenda used to design a boiler, parts thereof, and replacement parts shall be either those that are mandatory on the date the boiler or replacement part is contracted, or those that have been approved and issued by ASME prior to the contract date but are not yet mandatory (refer to General above).*
- b. Existing pressure parts that have been stamped and certified to an earlier or later Edition and Addenda than those used for design, and that have never been placed in service, (i.e., placed on the shelf for future use) may be used provided they are acceptable to the Manufacturer.*
- c. It is permitted to provide a replacement part "in kind" (i.e., identical in fit and material to the part being replaced) for an existing boiler and to certify the part as meeting the Code Edition and Addenda to which the existing boiler is certified.*

Paragraph c addresses those instances when using the latest Code Edition would not provide a replacement part that fits the existing unit (e.g., a tube sheet may be thicker). This rule makes it permissible to supply a replacement part in kind and to certify the design to the original Code Edition and Addenda.

Materials

For pressure-containing parts, the Manufacturer shall use material conforming to one of the specifications listed as approved for use in the Edition and Addenda specified for design. Also, the material specification edition must be listed as approved for use in the Guideline for Acceptable ASTM Editions or in the Guideline for Acceptable Non-ASTM Editions in Section II, Parts A or B.

These words are generally the same as those in the existing Foreword and do not change what has generally been followed as rule in the past.

Fabrication

The Edition and Addenda used to govern fabrication may be the same as those governing design or the Edition and Addenda approved and issued at the time the activity is performed.

It was noted during task group discussions with a significant number of manufacturers that shop fabrication practices are updated to satisfy the rules of the latest Addenda. This permits use of later rules and would not require recording of the Edition and Addenda in which they are described.

Examination

Examination refers to activities performed by the Manufacturer which include non-destructive examination. The Edition and Addenda used to govern examination may be the same as those governing design or the Edition and Addenda approved and issued at the time the activity is performed.

Inspection

Inspection refers to activities performed by the Authorized Inspector. The Code Edition and Addenda used to govern inspection shall be the same as those governing design.

Testing

The Code Edition and Addenda used to govern testing of the item shall be the same as those governing design.

Use of testing methods (e.g., pneumatic) not addressed in the Edition and Addenda governing design would require the use of a Code Case.

Over Pressure Protection

The Code Edition and Addenda used to govern over pressure protection shall be the same as those governing design.

Use of rules governing overpressure protection not addressed in the Edition and Addenda governing design would require a Code Case.

Field Assembly

The Edition and Addenda used to govern field assembly may be the same as those governing design or the Edition and Addenda approved and issued at the time the activity is performed.

Certification

The Edition and Addenda used to govern Code certification shall be the same as those governing design.

Note under General, above, that once the Edition of Section I to be used is established, the manufacturer is not obliged to implement any changes made in subsequent Addenda or Editions. This is a practical approach, but also note that in the second paragraph the manufacturer is advised to consider “changes that may be critical to the intended service of the boiler” and to reach an agreement with the user on whether to apply the changed rules. See further discussion under the related issue of ASME Code Edition Applicable to Repairs and Alterations in Chapter 16.

MATERIALS

HOW MATERIAL IS ORDERED

Material is a fundamental link in the chain of ASME Code construction, and great care is taken to assure its quality. The ASME accomplishes this by adopting material specifications that have been developed and adopted first by the American Society for Testing and Materials, the ASTM. The ASME material specifications are thus usually identical to those of the ASTM. ASTM issues specifications designated by letter and number, for example, A-106, Seamless Carbon Steel Pipe for High Temperature Service. When the ASME adopts ASTM specifications, it adds the letter S. The equivalent ASME pipe specification is thus SA-106.

In keeping with the ASME's policy to internationalize its Code, ASME has adopted a number of foreign material specifications. These are included in Section II, Part A as a single cover sheet for each specification (a complete material specification has not been reproduced in Section II, Part A, as is done for the ASTM material specifications). For example, Section I permits the use of SA/AS 1548, Steel Plates for Pressure Vessel Equipment, an Australian Standard Material Specification. If a boiler manufacturer chooses to use one of the permitted foreign material specifications in the construction of his Section I component, then he will be obliged to obtain a copy of the relevant material specification.

The ASME or SA material specifications are used as purchase specifications. Each specification contains a variety of information appropriate to that product, dealing with how it is ordered, the manufacturing process, heat treatment, surface condition, chemical composition requirements, tensile requirements, hardness requirements, various test requirements, and how the material is to be marked. The purchaser can also specify nonmandatory supplementary requirements, dealing with such things as stress relieving, nondestructive examination, and additional testing. All of these requirements have evolved over the years in response to the needs of the users.

The purchaser orders by specification number, and the supplier certifies that the material complies with that specification. In most cases, furnished with the material are material test reports that provide the results of various tests required by the specification.

USING SECTION II

Section II of the ASME Code contains information on materials. It is a four-part compendium of materials data, almost a foot thick in its entirety. The four volumes are as follows:

- Part A—Ferrous Material Specifications
- Part B—Nonferrous Material Specifications

Part C—Specification for Welding Rods, Electrodes, and Filler Metals

Part D—Properties

Parts A, B, and C are, as their names indicate, a compendium of ASME material specifications for all the pressure vessel and welding materials permitted for use in Code construction by Sections I, III, IV, VIII, and XII. It is important to remember that not every material listed in Section II can be used in Section I construction. In general, only materials listed in the material paragraphs of Section I, i.e., PG-5 through PG-14 and PW-5, may be used for Section I pressure-retaining parts. PG-11 also permits the use of most materials listed in the ASME standards recognized by Section I in PG-42, such as the ASME standard Pipe Flanges and Flanged Fittings, B 16.5. Materials not otherwise listed for Section I service may also be used if they are listed in a Section I Code Case (see Code Cases in Appendix II). Section I also sets temperature limits for the use of the various materials. They must be used within the temperature range for which allowable stress values are tabulated in Section II, Part D, Properties. The maximum temperature listed for Section I use is 1650°F (900°C), for high alloy steels used in superheaters.

With the publication of the 1992 edition of the Code, the allowable stresses that were in Table PG-23 of the earlier editions of Section I were transferred to Section II, Part D, a thick volume subtitled Properties. The allowable stresses from Section I and those from Sections III and VIII were consolidated and reformatted into this single volume. This consolidation facilitates uniformity among those Code sections that use the same criteria for establishing allowable stress. (Note that some sections, e.g., Section VIII, Division 2, use different criteria, which generally result in higher allowable stresses than those of Sections I and VIII, Division 1. Conversely, Section IV, Heating Boilers, uses lower stresses, in part to make up for the fact that less nondestructive examination is used in the construction of these relatively low-pressure boilers.) The allowable stresses for ferrous materials used in Section I construction are listed as a function of temperature in Table 1A of Section II, Part D. Allowable stresses for copper, copper alloys, nickel, and nickel alloys are listed in Table 1B. These Part D tables have many important footnotes covering conditions of use, footnotes that formerly appeared with the separate stress tables in the various book sections.

Section II, Part D is organized into subparts covering stress tables, physical-property tables, and external pressure charts. Also included are a number of mandatory appendices. Two appendices describe the bases for establishing the allowable stress and allowable design stress intensity values (the latter are used in the design of Class 1 nuclear power plant components). Another describes how charts for external-pressure design are established and what criteria are used to determine allowable compressive stresses when designing for external pressure. Other mandatory appendices explain the means by which a new material can be approved for Code use; preparation of Technical Inquiries to the Boiler and Pressure Vessel Committee, Guideline for Multiple Marking of Material, and Standard Units for Use in Equations. In addition, there are two nonmandatory appendices covering: A. Metallurgical Phenomena and B. Guidance for use of U.S. Customary and SI Units in the ASME Boiler and Pressure Vessel Code.

A useful feature of Section II, Part D is the physical-property tables. They provide such information as the coefficient of thermal expansion, thermal conductivity, thermal diffusivity, modulus of elasticity, Poisson's ratio, modulus of rigidity, density, melting-point range, and specific heat for a fairly large variety of materials. Much of this information is provided over a large temperature range. Also included are tables of yield and ultimate tensile strength as a function of temperature. Modulus of elasticity at design temperature is used in the design calculations of PFT-51 for cylindrical furnaces and tubes under external pressure. Yield strength at test temperature is used in the design calculations of the boiler components for the hydrostatic test requirements of PG-99.1.

Finding the allowable stress for a particular material can sometimes be difficult if one is not familiar with the material stress tables in Section II, Part D, Properties. It is difficult to find a particular material specification because there are so many, and they are not listed in numerical order. Instead, they are listed by some not readily apparent rules having to do with increasing content of certain alloying elements. The listing is based on the sorting order the committee used. The sorting order for materials differs between the tables for ferrous

materials (SA specifications) and nonferrous materials (SB specifications). The five-level sorting sequence for ferrous materials is as follows:

1. Nominal composition (more on this below)
2. Tensile strength
3. Yield strength
4. Specification number
5. Grade or type

While this seems simple enough, establishing a rule to sort materials in an ascending order of nominal composition is difficult; no single rule works universally, so several arbitrary choices were made. Ferrous materials were listed in the following order of nominal composition:

1. Carbon steels; C, C-Si, C-Mn, and C-Mn-Si steels.
2. Microalloy carbon steels; C-steels with Cb, V, and Ti added.
3. Low alloy steels (C-1/2 Mo, followed by Cr-xx-where xx represents a second element such as Mo, Ni, W, Ti, etc. — ordered on the basis of increasing Cr to 9Cr-1Mo-V).
4. High alloy ferritic, martensitic, and duplex stainless steel ordered by increasing Cr content, beginning at 11Cr-Ti and finishing at 29Cr-4Ni-Ti. Within the same Cr content, a second sort on the second element, e.g., Ni or Mo, was performed. Within this group, the second element never exceeds 4%.
5. A hard-to-categorize group of low alloy ferritics that have Mn and Si identified in their nominal compositions, beginning with Mn-1/4Mo and ending in 1 1/2Si-1/2Mo.
6. Nickel alloy steels ordered according to nickel compositions beginning with 1/2Ni-1/2Cr-1/4Mo-V and ending with 28Ni-19Cr-Cu-Mo.
7. The Cr-Mn and Cr-Ni austenitic (and perhaps some duplex) stainless steels beginning with 16Cr-9Mn-2Ni-N and ending with 25Cr-22Ni-2Mo-N, sorted by increasing Cr content and, within the same Cr content, increasing second element (e.g., Ni) content. In general, this sort on second-element content within the same major-element content applies to the previous categories, i.e., 2 through 6 above.

For the nonferrous materials, the order of the sort is as follows:

1. Alloy/UNS number (alpha-numeric)
2. Tensile strength
3. Yield strength
4. Class/condition/temper
5. Specification number

It is thus apparent that unless a designer knows the nominal composition of a material or its UNS number, he or she will have some difficulty in finding that material in the tables of Part D. However, there are a number of reference books that can help. One of these is the *CASTI Guidebook to ASME Section II, B31.1 & B31.3 Materials Index (Tenth Edition)*, by R.A. Moen, which lists and cross-indexes a great deal of useful information about Section II, such as nominal material compositions, material properties, and which materials are permitted for use in the various book sections. Another useful book is *Metals and Alloys in the Unified Numbering System*, which lists and cross-indexes materials of chemically similar specifications. The Unified Numbering System for Metals and Alloys (UNS) provides a means of correlating many nationally used metal and alloy numbering systems currently administered by societies, trade associations, and individual users and producers of metals and alloys. A UNS designation is not, in itself, a specification, since it is based on chemical composition and establishes no limits for form, condition, property, or quality. It is rather a unified identifier of a metal or alloy for which controlling limits have been established in specifications published elsewhere, by ASME, ASTM, SAE, and others.

FINDING AND USING DESIGN STRESSES IN SECTION II, PART D

The designer must determine which stress line for a particular material pertains to Section I (or one of the other Sections) by referring to the second page of the four pages of information under four columns designated “Applicability and Maximum Temperature Limits.” There is one column for Section I, one for Section III, one for Section VIII, Division 1, and one for Section XII. Only if there is a maximum use temperature listed in one of these columns may the material be used for construction covered by that section of the Code. Otherwise, the letters NP appear, meaning not permitted. This has led to a number of problems. In Chapter 11, under Standard Pressure Parts, it is explained that such parts (covered in PG-11) which comply with any ASME product standard accepted by reference in PG-42 may be made of any material listed in that standard, “but not of materials specifically prohibited, or beyond the use limitations of this Section.”

Section I does have some constraints on the use of various materials, but it has no outright prohibitions against the use of any specific materials. For example, footnote 1 of PG-5.5 cautions that austenitic stainless steels are not to be used for boiler pressure parts that are water-wetted in normal service, although there are exceptions to this rule. The expression “beyond the use limitations of this Section” pertains to temperature limitations. One is the maximum design temperature for any given material, now established by the highest temperature at which a stress value for Section I use is listed in Section II, Part D. Materials such as cast iron and bronze have relatively low temperature limits, which are stipulated in PG-8 and PG-9.

The letters NP (not permitted) that appear in the Section II, Part D columns on applicability of material for a given book section were applied by default if that material had not been listed for use in that book section before the advent of Part D. Therein lies a problem because there are many materials listed in the ASME product standards accepted by Section I by reference in PG-42 that had never been listed in the Section I stress tables. No Authorized Inspector had previously challenged the use of those materials in these ASME product standards because their use was (and is) explicitly sanctioned by PG- 11. However, a problem arose once the designation NP appeared in Part D. One of the authors’ companies found itself facing the following situation: It had designed and subcontracted to another stamp holder the fabrication of an austenitic stainless steel superheater whose return bends were purchased as standard elbows made in accordance with ANSI B16.9 (now ASME B16.9), Factory-Made Wrought Steel Butt welding Fittings. The manufacture of B16.9 elbows starts with pipe or tube made from a material that is designated only by class and grade (e.g., WP 304) and that meets the chemical and tensile requirements of SA-403, Specification for Wrought Austenitic Stainless Steel Pipe Fittings. When the elbow is completed in accordance with the provisions of SA-403 and ASME B16.9, it is given a new material designation, A-403 or SA-403, as a fitting. Unfortunately, Section I had never listed that material, but it had been listed in Section VIII. Accordingly, the Section II, Part D column for Section I applicability listed SA-403 as NP, not permitted; it was apparently permitted only for Section VIII construction.

The AI at the fabricator saw that listing and proclaimed that the elbows could not be used in Section I construction, stopping fabrication on a contract with heavy daily penalties for late completion. Fortunately, the Authorized Inspection Agency providing the AI at the job site had knowledgeable Code committee members who quickly agreed that the designation NP should not apply in these circumstances, or rather, should not mean NP if PG-11 provides otherwise. Section I subsequently issued Interpretation I-92-97, which solved the problem for these particular fittings, but did nothing about the generic problem of the potentially misleading designation Not Permitted in Section II, Part D. An attempt to have BPV II modify the NP designation with a note referring to PG-11 proved unavailing, so the unwary designer faces a potential trap in a situation similar to the one just described.

Interpretation I-92-97 is as follows:

Question: *May SA-403 austenitic fittings made to ASME/ANSI standards accepted by reference in PG-42 be used for Section I steam service?*

Reply: *Yes.*

An earlier interpretation that happened to apply to boiler external piping, and to only three of the many ANSI (currently ASME) product standards listed in PG-42, supports the basic philosophy of PG-11 that materials listed in those standards are acceptable for Section I use. That Interpretation was I-79-01:

Question: May flanges and pipe fittings made of materials conforming to ASTM specifications, produced and identified in accordance with ANSI B16.5, B16.9, and B16.11 be used in boiler external piping?

Reply: Flanges and pipe fittings made to ASTM specifications and conforming to the referenced ANSI standards may be used in Boiler External Piping provided the requirements of PG-11 are met.

Question: If these components are used as provided for above, are certified test reports or additional inspection required?

Reply: Certified test reports or additional inspection will not be required provided the requirements of PG-11 are met.

The reply to the first question in the above interpretation illustrates that the material listings in the ASME/ANSI B16 standards for components such as valves and pipe flanges and fittings are given ASTM designations, not ASME designations. One reason for this is that these standards are used in many applications having nothing to do with the ASME Code. PG-11.1.1 explicitly permits the use of these ASTM materials when listed in ANSI product standards accepted by reference in PG-42.

It is interesting to note that ASME Section II, Part D still (2010) lists SA-403, seamless and welded fittings, as being NP (not permitted) for Section I construction. However, PG-11.1 of the current (2010) Edition permits the use of *Standard pressure parts that comply with some ASME Standards and are made of materials specifically listed in an ASME product standard listed elsewhere in this Section but not of materials specifically prohibited or beyond the use limitations in this Section*. PG-42 of Section I lists B16.9 (among others) as applicable ASME Standards for fittings, flanges and valves that may be used in Section I construction without the need for *inspection, mill test reports, or Partial Data Reports*.

MARKING OF MATERIALS

The ASME material specifications typically contain marking requirements intended to provide proper identification and assurance that the material is what it is supposed to be. These marking requirements are found both in a general specification that gives general requirements for the particular product form, such as piping or tubing, and in the specification covering the material in question. Thus, for example, pipe furnished to SA-106 must be marked as prescribed in the general specification covering carbon steel pipe (SA-530) and with the additional marking called for in paragraph 24 of the SA-106 specification, which is quite detailed. That paragraph also stipulates that when pipe sections are cut into shorter lengths by a subsequent processor for resale as material, that processor must transfer complete identifying information to each unmarked cut length or to metal tags securely attached to bundles of unmarked, small-diameter pipe. The material designation must be included with the information transferred, and also the name, trademark, or brand of the processor.

It is important that a boiler manufacturer have some provision in its quality control system to assure the proper identification of material during fabrication, so that the correct material is used. Section I has some very old and specific provisions in PG-77 regarding the identification of plate material used in the boiler. They call for the material identification information to remain visible on shell plates, furnace sheets, and heads after the boiler is completed. It is permissible to use coded markings instead of the full identification for this purpose. The system of transferring markings when plate is cut must be acceptable to the AI. Section I is silent on maintenance of markings on other product forms, such as pipe or tube. These are usually marked at regular intervals by the material manufacturer, in accordance with the requirements of the material specification, and it suffices if the fabricator has a system for assuring that the proper material has been used.

There have been a number of clarifying interpretations on marking requirements. Interpretation I-79-02 dealt with the subject:

Question: Does Section I require any additional information or marking (e.g., heat number marking, mill test reports, etc.) beyond that required by a Section I referenced specification [sic] in Section II?

Reply: Section I has no supplementary requirements in this area.

The usual marking requirements do not apply to piping smaller than NPS 2 (DN 50) or to tubing smaller than 1¼ in. (32 mm) in diameter. The generic product form specifications SA-450 and SA-530 permit the required information to be marked on a tag securely attached to the bundle or box in which such small-diameter piping or tube is shipped.

Another interpretation dealing with marking was I-92-83, dealing with nonpressure parts:

Question: If nonpressure parts, such as lugs, hangers, or brackets, are cut from weldable material (PG-55.2), is it a requirement of Section I that the product marking be transferred to each piece?

Reply: No.

A related topic is whether the markings have to remain visible during construction or upon completion of the boiler. This was addressed in a lengthy but informative interpretation entitled Identification of Materials and Miscellaneous Parts During and After Construction, I-95-08:

Question: Identification markings required for material by the material specification and for miscellaneous parts by PG-11 are verified by the Manufacturer during receipt inspection. During construction of the boiler, the material and miscellaneous pressure parts are controlled in accordance with the Manufacturer's approved material control system. The material control system provides methods acceptable to the Authorized Inspector for assuring that only the intended material is used in Code construction. Under these conditions and except for the special identification requirements of PG-77, must the identification markings required by the material specification and by PG-11 remain visible during construction of the boiler?

Reply: No.

USE OF NON-ASME MATERIAL SPECIFICATIONS AND MATERIAL NOT FULLY IDENTIFIED

Both Sections I and VIII, Division 1 have long had provisions (PG-10 and UG-10) dealing with the acceptance of material made to specifications not permitted by Section I or Section VIII (which could, for example, be an ASME specification or a foreign material specification) and with the acceptance of material of any kind that is not fully identified. In 1987, these provisions were expanded to provide more guidance on what must be done, and who may do it, when a material is requalified as the equivalent of an acceptable ASME material. The recertification or requalification process differs, depending on which of two categories of organization is doing the recertifying and whether the material is fully identified with a complete certification from the material manufacturer. The first category of organizations comprises only boiler or boiler-parts manufacturers. The second category comprises any other organizations. When PG-10 and UG-10 were revised in 1987, the burden of proof that a given material was the equivalent of a material acceptable to Section I (or Section VIII) was made greater for organizations that were not either boiler or boiler-parts manufacturers, for two reasons. These other organizations were often material warehouses that bought material from material manufacturers and resold it to users. Under the less stringent pre-1987 recertification rules, these organizations were, in many cases, found to be recertifying materials as the equivalent of other materials so that they could sell material they had in stock even if full equivalency of all details of manufacture, chemistry, and mechanical

properties could not be shown. Accordingly, the rules for those organizations were made more stringent. Boiler and boiler-parts manufacturers were allowed a lower burden of proof because they had more to lose if the recertified material turned out to be less than satisfactory; it was they, after all, who were taking design responsibility for either the boiler or the parts, or both.

Thus, to recertify a material that had complete certification from the material manufacturer as another material, an organization other than a boiler or boiler-parts manufacturer must meet the rules of PG-10.1.1, documenting complete equivalency of the respective specifications. Moreover, such an organization must certify that it has done this and must provide its certification, with copies of documentation proving conformance, to the boiler or boiler-parts manufacturer. This is a very heavy burden of proof. In contrast, the rules of PG-10.1.2 allow a boiler or boiler-parts manufacturer to meet a somewhat lower burden of proof of equivalency, simply by making available to the Authorized Inspector documentation showing that the chemical requirements of the desired specification have been met and that no conflict exists between the requirements of the two specifications. Documentation must also be made available to the AI demonstrating that any other requirements of the desired specification have been met.

When material cannot be requalified as just described because, for example, complete certification from the material manufacturer is lacking, the rules of PG-10.2 and PG-10.3 may be used to demonstrate acceptability of a specification not permitted by Section I. These rules may be used only by a boiler or boiler-parts manufacturer, for the reasons just explained. In such cases, chemical analyses and mechanical property tests are employed to demonstrate that the desired material is the equivalent of one that is normally allowed for Section I construction.

Once a material has been established as the equivalent of an acceptable specification, it may be marked as required by that specification.

With the increasing emphasis on global competition, the ASME Boiler and Pressure Vessel Committee has sought ways in which to gain wider international acceptance of ASME Code construction. This is a two-way street, and the ASME recognizes the need to remove unnecessary barriers to the use of ASME construction, in the hope that other countries will reciprocate. One of these barriers was ASME's previous insistence that only ASME or ASTM materials could be used in ASME construction. Recognizing the many areas of the world where economic constraints or local rules may necessitate the use of non-ASME materials, the ASME relaxed its policy, and in 1997, Section II approved the first two foreign material specifications for inclusion in the 1998 Addenda. Those specifications covered a Canadian structural steel, CSA-G40.21, and a European carbon steel plate, EN 10028-2. It happens that these two materials are very similar to two existing ASME materials, SA-36, a structural steel, and SA-516 Grade 65, a common material used for pressure vessels. With the publication of the 2010 Edition, ASME has adopted a total of eight (8) foreign specifications from Australia, Canada, China, Europe, and Japan. These specifications include a total of 18 materials, of which eleven (11) are permitted for Section I construction.

SPECIAL CONCERNS

A number of Section I material applications deserve special mention. One of these, having to do with the use of austenitic stainless steels in water-wetted service, used to be mentioned in footnote 1 to PG-5. (In late 1997, the Standards Committee approved BPV I's action to move and clarify the advice in that footnote into a new paragraph PG-5.5. This new paragraph was published as part of the 1998 Addenda incorporated into the 1998 edition of Section I.) Austenitic steels are particularly susceptible to stress corrosion cracking. Consequently, Section I generally limits the use of these steels to what it calls steam-touched service and prohibits their use for water-wetted service, where chlorides or sulfides might be present. Those stainless steels listed in PG-9.1 for boiler parts (normally water-wetted) are ferritic stainless steels, which are not susceptible to stress corrosion cracking. There are, however, several exceptions to the rule.

An exception is made for surfaces that are water-wetted only during start-up of the boiler, since this is considered a short enough time that the risk of corrosion is quite limited. This exception was granted by means

of Interpretation I-79-09, in response to a request from a manufacturer regarding a special type of boiler in which the steam headers contained water during start-up. Here is that interpretation:

Question: May austenitic stainless steel be used for portions of the boiler proper and the boiler external piping which are water-wetted only in start-up service?

Reply: Austenitic stainless steel may be used for portions of the boiler proper and the boiler external piping which are water-wetted only for start-up service.

Note the mention of boiler external piping in this reply. It happens that no such mention was needed, since the material requirements for boiler external piping are found in Power Piping, B31.1, and that code has no prohibition against austenitic stainless steel in water-wetted service. This probably comes about from the fact that usually piping is not transferring heat; thus, no boiling takes place inside the pipe. Without boiling to concentrate any deleterious species such as chlorides in the water, the likelihood of chloride-induced stress corrosion cracking of austenitic steel is greatly reduced. A second reason for any lack of a prohibition in B31.1 against the use of austenitic steels for water-wetted service is that such a prohibition is hardly needed; it would be extremely unusual, unnecessary, and uneconomical for such material to be used for feedwater piping. Finally, Section I's prohibition against the use of austenitic stainless steel in water-wetted service was buried in a footnote to PG-5 and was none too clear. Consequently, it was probably overlooked when most of the rules covering boiler external piping were transferred to B31.1 in 1972. Occasionally, a designer wants to use austenitic stainless steel for a chemical feed line to the boiler and may feel constrained from doing so by Section I's apparent prohibition. However, the chemical feed line is a part of the boiler external piping, and the prohibition does not apply.

Another exception allowing the use of austenitic stainless steels in water-wetted service had been granted under the provisions of Code Case 1896, *Miniature Electric Boilers Fabricated of Austenitic Stainless Steel* (refer to Appendix II for an explanation of Code Cases). These boilers are used in special applications, such as in the pharmaceutical industry, where steam of great purity is required. One of the provisions of the case is a requirement that very pure water is to be used, thereby making it unlikely that chlorides will be present. Case 1896 was incorporated into a new PEB-5.3, in the 1998 Addenda. A number of other cases, such as Code Case 1325, also permit the use of very high alloy austenitic stainless steels, such as Incoloy 800 (a trade name that the ASME designates as Nickel-Iron-Chromium Alloy 800, UNS N08800) in water-wetted service. In the early 1990s, a warning about the potential susceptibility of these austenitic steels to various kinds of stress corrosion cracking in water-wetted service was added to all such Code Cases. However, the high content of chromium and nickel in these steels is sufficient to prevent most corrosion problems in water-wetted service; their application has generally been quite successful. A similar warning was added as a footnote to the new PG-5.5. It appeared in the 1998 Addenda.

The last exception in which austenitic steel is allowed in water-wetted service came in through the back door, as follows: Some time in the early 1980s, it came to the attention of Subcommittee I (now BPV I) that gage glass bodies of austenitic stainless steel had been used for many years, despite the footnote in PG-5. The manufacturers of these devices stated that this water-wetted service presented no problem of chloride stress corrosion cracking because no boiling takes place at the gage glass body (and thus chlorides were not concentrating there the way they would in a tube subject to heating). They also claimed that the use of stainless steel improved the visibility of the water in the glass because there was less iron oxide to cloud the glass. Moreover, they noted that to provide firm support for the relatively fragile gage glass, the body of the device is always oversized to achieve stiffness. As a result, the pressure stresses in the body were below the 7000-psi (47-MPa) threshold normally considered necessary to initiate chloride stress corrosion (this threshold is actually a function of alloy and temperature). Finally, they cited quite a few years of successful experience. After considering all this evidence, BPV I approved a new paragraph, PG-12, specifically permitting the use of austenitic stainless steel for gage glass bodies. A new PG-5.5 now identifies this and other exceptions to the general prohibition against the use of austenitic stainless steel in water-wetted service.

Another concern is the problem of **graphitization**, a type of microstructural deterioration that occurs in carbon and carbon-molybdenum steels from the decomposition of iron carbide into ferrite and graphite. This

decomposition is a time and temperature-dependent relationship that begins to become significant only after long service at temperatures above about 840°F (450°C) (it occurs more quickly at higher temperatures). Graphitization can severely affect the strength and ductility of these steels, particularly the heat-affected zone of welds, where the graphite usually lines up as chain graphite. Note G10 in the allowable stress table (Table 1A of Section II, Part D) cautions: “Upon prolonged exposure to temperatures above 800°F, the carbide phase of carbon steel may be converted to graphite.” Some members of BPV I are in favor of prohibiting any use of carbon steels above 800°F (425°C), but others think this is not necessary, that the designers should be allowed to use their own judgment. They note also that even with a design temperature slightly above 800°F (425°C), the components are likely to be operating at 800°F (425°C) or lower and that graphitization is not a significant problem at these relatively low temperatures, especially if excursions over 800°F (425°C) are infrequent and of short duration.

The use of cast iron and nonferrous metal castings is permitted by Section I only for those applications mentioned in PG-8, for relatively low temperature and pressure.

MATERIAL REQUIREMENTS FOR BOILER EXTERNAL PIPING

These are contained in 123.2.2 of B31.1, Power Piping. They are virtually the same as those of Section I in calling for the use of ASME SA, SB, or SFA specifications (Section IX does not actually require the use of SFA specifications for welding consumables). Material produced under an ASTM specification may be used, provided the requirements of that specification are identical or more stringent than the equivalent ASME specification for that particular category of material (grade, class, or type). For nonboiler external piping, which is entirely outside of Section I’s jurisdiction, B31.1 allows material produced to ASTM A or B specifications to be used interchangeably with material specified to ASME SA or SB specifications of the same number.

Miscellaneous pressure parts (see PG-11) such as valves, fittings, welding caps, etc., are often furnished as standard parts. As already explained, when those parts meet the requirements of the ASME standards adopted by reference in PG-42, Section I accepts the materials listed in those standards, unless they are specifically prohibited or are beyond the use limits of Section I. However, standard parts made to a parts manufacturer’s standard must be made only of materials explicitly permitted by Section I. This is discussed in Chapter 11, under Standard Pressure Parts.

ELECTRIC RESISTANCE WELDED (ERW) MATERIALS

When the Code first accepted tubes and pipes formed of electric resistance welded (ERW) materials, it imposed a 15% penalty on allowable stress, except for tubes within the boiler setting whose design temperature was 850°F (455°C) or lower. There was apparently some doubt about the welding, and the use of the normal allowable stress was permitted only for tubes inside the protective barrier of the setting. Because of the good service record of these tubes in recent years, some thought is being given to removing the penalty on ERW tubes. As a first step in this direction, in 1988, several Code Cases were passed (CC 2041, 1942, 1996, 1984, and 2026) permitting the use of ERW tubes within the allowed design temperature range without the 15% reduction in allowable stress, if they meet three conditions: the tubes are given extra nondestructive examination (angle beam ultrasonic inspection and an electric test in accordance with ASME specification SA-450), the tubes are no larger than 3½ in. (89 mm) OD, and the tubes are enclosed within the setting.

Code users often wonder just what the term “within the setting” means, since this term is not defined in Section I. Various books on boiler construction typically define the setting as the construction surrounding either the boiler or the tubes, or both: refractory, insulation, casing, lagging, or some combination of these. In former years, with heavy casing and refractory, it could be argued that a failed tube would not represent much of a danger to someone standing nearby. As simpler and lighter construction has evolved, there may be only

insulation and relatively thin lagging outside the tubes or enclosing a header. Although such construction may not provide as strong a barrier as formerly, it is the industry's position, accepted by the Authorized Inspectors, that the tubes are still "enclosed within the setting," and if they meet the other provisions of the Code cases cited, they would be entitled to the full allowable stress without the 15% penalty of former years. That penalty was, in effect, a vote of no confidence in the electric resistance weld and/or the inspection of the weld.

Any grease or other contamination of the surfaces to be welded has the potential for preventing a sound weld, and careful inspection has always been important in assuring that any bad welds will be found. However, the 15% penalty was always an arbitrary one. If the weld were truly bad, it would leak. Lowering the stress by 15% would not really help. There has now been quite a lot of good experience with ERW tubes, and the additional NDE called for in the Code Cases should, henceforth, provide some further assurance that any bad welds will be detected. After extensive satisfactory use, the provisions of the above noted Code Cases have been incorporated into Section 1.

NONPRESSURE PART MATERIALS

Material for nonpressure parts, such as lugs, hangers, brackets, or fins, is not limited to material listed in the stress tables, but must be of weldable quality. "Weldable quality" is a rather vague term, and the choice of nonpressure material is thus left to the designer. The fact that a material is of weldable quality is established when the procedure used to weld it is qualified. For carbon and low alloy steels, PW-5.2 also stipulates another requirement for weldability: the carbon content may not exceed 0.35%.

MATERIAL TEST REPORTS

Although there is no specific reference within the text of Section I to a requirement that a material test report be furnished, PG-105.4 calls for the quality control system to be in accordance with the requirements of Appendix A-301. Thus that appendix becomes mandatory, and paragraph A-302.4 on Material Control stipulates that the boiler manufacturer (or any other stamp holder who is involved in fabrication or assembly) "shall include a system of receiving control that will insure that material received is properly identified and has documentation, including required material certifications or material test reports (MTR's), to satisfy Code requirements as ordered." Typically, ASME material specifications have a paragraph called Ordering Information, which usually says, "Orders for materials under this specification shall include the following, as required, to describe the material adequately: . . . "For pipe products for example, the ordering information stipulated includes a report described as a "Test Report Required (Section on Certification of Specification SA-530/SA-530M)." Specification SA-530/SA-530M is entitled "Specification for General Requirements for Specialized Carbon and Alloy Steel Pipe."

Paragraph 21 of that specification is entitled "Certified Test Report." The substance of this paragraph is that the producer or supplier of the pipe material must furnish a report certifying that the material was manufactured, sampled, and tested in accordance with the governing specification and any other requirements in the purchase order or contract and that those requirements were met. The paragraph advises also that a signature or notarization is not required on the Certified Test Report, but that the document must be dated and must clearly identify the organization submitting it. Also, the submitting organization is responsible for the contents of the report, even in the absence of a signature or notarization.

In the case of tube products, the comparable reference for the test report is to Specification SA-450/SA-450M, Specification for General Requirements for Carbon, Ferritic Alloy, and Austenitic Alloy Steel Tubes. Paragraph 27 of SA-450 deals with the Certified Test Report and is identical to paragraph 21 of SA-530, just described. Plate materials and forgings also have specifications (SA-20 and SA-788) that give general requirements for those product forms. The test report paragraphs of those specifications are similar to those just described. The terminology used for these various test reports in the general requirements specifications and the individual

material specifications varies somewhat because it evolved over a long period of time: Material Test Reports (MTRs), Certificates of Compliance/Conformance, Certificates of Inspection, and Certified Material Test Reports. There is little actual difference among them, except that a Certificate of Conformance or Compliance is merely a statement of compliance or conformance with a particular specification, without test results. However even in specifications that call for such certificates (e.g., SA-234 and SA-403), there is a further statement that, if requested, the manufacturer shall provide reports of all tests called for in the specification. In most cases, an MTR serves to provide all the information needed, but the material specification and the general requirements specification should be reviewed to confirm this. Most boiler manufacturers routinely require the material manufacturer or supplier to furnish MTRs for all pipe, tube, and plate materials, since most AIs and ASME survey team members want to see those as evidence of the certificate holder's compliance with the Code.

Thus, although the advice in A-302.4 on material control could be a little more definitive, the industry construes it to mean that manufacturers are expected to specify in their material purchase orders that either material test reports or material certifications are to be furnished with the material. These documents provide a description of the material sufficient to determine that it satisfies the specification as to chemical composition, mechanical properties, and any other information that the specification requires to be reported. The Authorized Inspector routinely expects and wants to review the MTRs to help assure that the right material has been received and used.

Sometimes, one of the parties involved in constructing a boiler gets the mistaken notion that the boiler manufacturer, or a subtier stamp holder furnishing parts or piping for the boiler, is supposed to furnish material test reports as part of the documentation making up the Manufacturer's Data Report package. This is not the case. An Interpretation was issued on this subject in 1977 and then revised and reissued on December 20, 1982. It appears on page 5 of Interpretations Volume 12 as I-77-28R, Section I, Identification of Pipe Material:

Question: May A-53 and A-106 pipe be used to fabricate Section I boiler external piping without the need to provide certified mill test reports or manufacturer certification provided the pipe is marked in accordance with the ASTM "A" designation?

Reply: The manufacturer who orders pipe material for a Code application is responsible for ordering it to Code requirements and shall have a material control system that ensures that the proper material is used in Code construction. The manufacturer's certification includes acknowledgment that the material requirements of the Code have been met. This certification by the manufacturer properly countersigned by the Authorized Inspector who provides inspection service for that manufacturer, may be accepted by you or others as sufficient evidence of Code compliance.

The original version of this reply, I-77-28, had included the following additional advice:

The verification of the Authorized Inspector may be made by any of the following methods:

- (1) Review of the material test reports or Certificate of Compliance when available as provided for in the Code approved specifications.*
- (2) Review of product markings furnished as provided for in the Code approved specification. In these circumstances there is no Code obligation on you as a subsequent user or installer of such subassemblies to examine mill test reports for material covered by ASME Data Forms.*

STRENGTH OF MATERIALS AFTER FABRICATION

The fabrication of material into boiler components may involve all sorts of hot or cold metal working, such as bending, rolling, forging, flaring, or swaging. Heat treatment such as solution annealing or postweld heat treatment may be employed following various forming and fabrication operations. As a consequence, the as received mechanical properties of the material, such as yield strength, hardness, or ductility, may have changed. Typically, the ASME material specifications have been developed to provide material suitable for the various operations involved in boiler or pressure vessel manufacture, and the change in material properties

presents no problem, especially for experienced manufacturers who know what, if any, intermediate or post-fabrication heat treatment may be appropriate. Occasionally, a dispute arises about the strength or other properties of a material after it has been fabricated into components of a boiler. A purchaser may have the mistaken idea that the properties of the material after fabrication must match its properties in the as-received condition, when it met the specification requirements. Section I has issued several interpretations to correct this misapprehension. The first was I-80-19, which harks back to the days when BPV I still gave what today might be called consulting advice, especially if the inquirer resided overseas and was thought to be having difficulty in understanding the Code.

Question: In construction of a power boiler in accordance with Section I, cracking has been observed in the ends of waterwall tubes that had been cold reduced from 3-in. diameter to 2-in. diameter, the material had not been heat treated following cold reduction. Does Section I require a heat treatment of cold reduced ends of waterwall tubes?

Reply: Section I does not specifically address the heat treatment of cold reduced ends of waterwall tubes which are to be used in rolled tube joints. However, it is the responsibility of the Section I stamp holder to use only material that is free of rejectable imperfections (those that encroach on required minimum wall thickness). Further, it is the Section I stamp holder's responsibility to use only material that is suitable for the intended installations, such as tube expansion (see PG-10.2.2).

(Note by authors: At that time, PG-10.2.2 contained the following sentence, subsequently deleted when rules for acceptance of unidentified material were tightened in 1987: "Material specified as suitable for welding, cold bending, close coiling, and similar operations shall be given sufficient check tests to satisfy the inspector that it is suitable for the fabrication procedure to be used." Similar language is usually included in the material specifications.) *To provide tubes that can be expanded into drums without cracking, it is usually required to heat treat tube ends which have been cold reduced to the degree indicated in the inquiry.*

Another interpretation dealing with postfabrication strength of materials is I-83-01, Hardness of Swaged Portion of Boiler Tubes:

Question: Is it required that carbon steel tubes such as SA-210 A-1 which have undergone fabrication operations by the boiler manufacturer meet the maximum hardness specified in the specifications?

Reply: No. The maximum hardness specified in the Section II material specification is one of a number of requirements intended to ensure that the tubing furnished by the material manufacturer will withstand fabrication and installation requirements. Section I does not specify hardness limits for the tubing as fabricated and installed in a boiler.

A last and more recent interpretation on this subject, I-95-03, was issued in response to an inquiry about chromized tubes:

Question: Do the materials listed in PG-9 for Section I construction have to comply with the individual specification requirements after the manufacturer has performed fabrication on the material?

Reply: No.

COLD FORMING OF AUSTENITIC MATERIALS

Appendix A370 of Section II, Part D states in part "Cold forming operations performed during manufacture of austenitic stainless steel pressure parts may cause impaired service performance when the component operates in the creep range [above 1000°F (540°C)]. Heat treatment after cold forming at a temperature given in the material specification will restore the intended properties of the material and will minimize the threat of premature failure due to recrystallation during the time of operation."

For this reason, Section I introduced PG-19 COLD FORMING OF AUSTENITIC MATERIALS with the 1999 Addendum. For cold-bending operations, Section I permits exemption from the postforming heat treatment requirements when the forming strains are less than the proscribed maximum strain limits of Table PG-19. However, PG-19.2 requires heat treatment in accordance with Table PG-19 for flares, swages and upsets regardless of the amount of strain.

PG-19 includes the formulas for calculating the forming strain in cylinders, spherical or dished heads, pipes and tubes. Table PG-19 lists the austenitic materials permitted by Section I, which may be subject to postforming heat treatment.

For convenience, we have included a copy of Table PG-19 POST COLD-FORMING STRAIN LIMITS AND HEAT-TREATMENT REQUIREMENTS below.

TABLE PG-19 POST COLD-FORMING STRAIN LIMITS AND HEAT-TREATMENT REQUIREMENTS (REPRODUCED FROM ASME SECTION 1)

Grade	UNS Number	Limitations In Lower Temperature Range				And Forming Strains Exceeding	Limitations In Higher Temperature Range		And Forming Strains Exceeding	Minimum Heat-Temperature When Design Temperature And Forming Strain Limits Are Exceeded [Notes (1) And (2)]	
		For Design Temperature					For Design Temperature Exceeding				
		Exceeding		But Less Than or Equal To			Exceeding				
		°F	°C	°F	°C		°F	°C			
304	S30400	1,075	(580)	1,250	(675)	20%	1,250	(675)	10%	1,900	(1 040)
304H	S30409	1,075	(580)	1,250	(675)	20%	1,250	(675)	10%	1,900	(1 040)
304N	S30451	1,075	(580)	1,250	(675)	15%	1,250	(675)	10%	1,900	(1 040)
309S	S30908	1,075	(580)	1,250	(675)	20%	1,250	(675)	10%	2,000	(1 095)
310H	S31009	1,075	(580)	1,250	(675)	20%	1,250	(675)	10%	2,000	(1 095)
310S	S31008	1,075	(580)	1,250	(675)	20%	1,250	(675)	10%	2,000	(1 095)
310H											
CbN	S31042	1,000	(540)	1,250	(675)	15%	1,250	(675)	10%	2,000	(1 095)
316	S31600	1,075	(580)	1,250	(675)	20%	1,250	(675)	10%	1,900	(1 040)
316H	S31609	1,075	(580)	1,250	(675)	20%	1,250	(675)	10%	1,900	(1 040)
316N	S31651	1,075	(580)	1,250	(675)	15%	1,250	(675)	10%	1,900	(1 040)
321	S32100	1,000	(540)	1,250	(675)	15% [Note (3)]	1,250	(675)	10%	1,900	(1 040)
321H	S32109	1,000	(540)	1,250	(675)	15% [Note (3)]	1,250	(675)	10%	2,000	(1 095)
347	S34700	1,000	(540)	1,250	(675)	15%	1,250	(675)	10%	1,900	(1 040)
347H	S34709	1,000	(540)	1,250	(675)	15%	1,250	(675)	10%	2,000	(1 095)
347HFG	S34710	1,000	(540)	1,250	(675)	15%	1,250	(675)	10%	2,150	(1 175)
348	S34800	1,000	(540)	1,250	(675)	15%	1,250	(675)	10%	1,900	(1 040)
348H	S34809	1,000	(540)	1,250	(675)	15%	1,250	(675)	10%	2,000	(1 175)
230	N06230	1,100	(595)	1,400	(760)	15%	1,400	(760)	10%	2,200	(1 205)
600	N06600	1,075	(580)	1,200	(650)	20%	1,200	(650)	10%	1,900	(1 040)
601	N06601	1,075	(580)	1,200	(650)	20%	1,200	(650)	10%	1,900	(1 040)
617	N06617	1,200	(650)	1,400	(760)	15%	1,400	(760)	10%	2,100	(1 150)
690	N06690	1,075	(580)	1,200	(650)	20%	1,200	(650)	10%	1,900	(1 040)
800	N08800	1,100	(595)	1,250	(675)	15%	1,250	(675)	10%	1,800	(980)
800H	N08810	1,100	(595)	1,250	(675)	15%	1,250	(675)	10%	2,050	(1 120)
...	S30815	1,075	(580)	1,250	(675)	15%	1,250	(675)	10%	1,920	(1 050)
C-22	N06022	1,075	(580)	1,250	(675)	15%	...	...	...	2,050	(1 120)

GENERAL NOTE: The limits shown are for cylinders formed from plates, spherical, or dished heads formed from plate, and tube and pipe bends. When the forming strains cannot be calculated as shown in PG-19, the forming strain limits shall be half those tabulated in this Table (see PG-19.1).

NOTES:

- (1) Rate of cooling from heat-treatment temperature not subject to specific control limits.
- (2) While minimum heat-treatment temperatures are specified, it is recommended that the heat-treatment temperature range be limited to 150°F (85°C) above that minimum [250°F (140°C) temperature range for 347, 347H, 348, and 348H].
- (3) For simple bends of tubes or pipes whose outside diameter is less than 3.5 in. (89 mm), this limit is 20%.

Early in 2010, BPV I received from a Manufacturer an inquiry regarding the heat treatment requirements for austenitic materials that had been heated during the forming operation. The following interpretation was developed and issued on this subject:

Question: If the finishing forming-temperature for austenitic stainless steels is above the minimum heat-treating temperature given in Table PG-19, regardless of the amount of strain, do the requirements of PG-19 apply?

Reply: No.

As explained to the inquirer, the rules of PG-19 presume that the finishing-forming temperature is below the minimum heat-treatment temperature given in Table PG-19.

COLD FORMING OF CREEP STRENGTH-ENHANCED FERRITIC STEELS

With the 2010 Edition of Section I, the BPV I committee introduced a new material requirements for cold forming of creep strength-enhanced ferritic steels, grades 91 and 92. These were laid out in PG-20 of Section I,

TABLE PG-20 POST COLD-FORMING STRAIN LIMITS AND HEAT-TREATMENT REQUIREMENTS (REPRODUCED FROM ASME SECTION 1)

Limitations In Lower Temperature Range							Limitations In Higher Temperature Range			
For Design Temperature										
Grade	UNS Number	Exceeding		But Less Than or Equal To		And Forming Stains	For Design Temperature Exceeding		And Forming Strains	Required Heat-Treatment When Design Temperature and Forming Strain Limits are Exceeded
		°F	°C	°F	°C		°F	°C		
91	K90901	1,000	(540)	1,115	(600)	>25%	1,115	(600)	>20%	Normalize and temper [Note (1)]
		1,000	(540)	1,115	(600)	>5 to = 25%	1,115	(600)	>5 to = 20 %	Postbend heat treatment [Notes (2)–(4)]
92	K92460	1,000	(540)	1,115	(600)	>25%	1,115	(600)	>20%	Normalize and temper [Note (1)]
		1,000	(540)	1,115	(600)	>5 to = 25%	1,115	(600)	>5 to = 20 %	Postbend heat treatment [Notes (2)–(4)]

GENERAL NOTE: The limits shown are for cylinders formed from plates, spherical or dished heads formed from plate, and tube and pipe bends. The forming strain limits tabulated in the table shall be divided by two if PG-19.1 is applied. For any material formed at 1,300°F (705°C) or above, and for cold swages, flares, or upsets, normalizing and tempering is required regardless of the amount of strain.

NOTES:

- (1) Normalization and tempering shall be performed in accordance with the requirements in the base material specification and shall not be performed locally. The material shall either be heat treated in its entirety, or the cold strained area (including the transition to the unstrained portion) shall be cut away from the balance of the tube or component and heat treated separately or replaced.
- (2) Postbend heat treatments shall be performed at 1350°F to 425°F (730°C to 775°C) for 1 hr/in. (1 hr/25 mm) or 30 min minimum. Alternatively, a normalization and temper in accordance with the requirements in the base material specification may be performed.
- (3) For materials with greater than 5% strain but less than or equal to 25% strain with design temperatures less than or equal to 1,115°F (600°C), if a portion of the component is heated above the heat treatment temperature allowed above, one of the following actions shall be performed:
 - (a) The component in its entirety must be renormalized and tempered.
 - (b) The allowable stress shall be that for Grade 9 material (i.e., SA-213 T9, SA-335 P9, or equivalent product specification) at the design temperature, provided that portion of the component that was heated to a temperature exceeding the maximum holding temperature is subjected to a final heat treatment within the temperature range and for the time required in Note (2) above. The use of this provision shall be noted on the Manufacturer's Data Report.
- (4) If a longitudinal weld is made to a portion of the material that is cold strained, that portion shall be normalized and tempered, prior to or following welding. This normalizing and tempering shall not be performed locally.

including new Table PG-20 with clarifying notes (Table PG-20 is included above for information). Note 3 permits the use of this material when heated beyond the permitted heat-treatment temperature, when certain conditions are met.

DOES NEW MATERIAL GET OLD?

The Foreword to all sections of the Code used to explain that revisions to the Code are issued as yearly Addenda on December 31. (However this changed to July 1, starting in 1998. See Effective Dates of the Code and Code Revisions in Chapter 2.) These revisions become mandatory six months later, except for boilers and pressure vessels contracted for prior to the end of the six-month period. However, the Foreword has never specifically addressed what must be done about revisions to the material specifications listed in Section II. These have traditionally been treated differently from revisions to the Code. As explained below, ASME now provides at the beginning of Parts A and B of Section II, GUIDELINE ON ACCEPTABLE ASTM EDITIONS, Table ED-1 (formerly called Appendix A) a list of all the materials approved for Code construction and the book sections in which they are approved for use. The list shows the latest material specifications adopted by the ASME and the dates of earlier versions considered equivalent and acceptable, going back in some cases to 1980. There is also Table ED-2, GUIDELINE ON ACCEPTABLE NON-ASTM EDITIONS, covering foreign specifications that have been accepted by ASME. Thus, except for unusual situations, manufacturers can readily determine the acceptability of any particular material on hand.

The story of the development of Table ED-1 is instructive. Until the mid-1980s, it had generally been understood that old (but previously unused) material could be used in boiler and pressure vessel construction. That is, if a manufacturer happened to have in inventory a lot of SA-213 tubes or SA-515 plate that had been manufactured years earlier, the manufacturer could use those materials for construction under the latest edition of the Code.

Confirmation of this practice is seen in the declarations the manufacturer signs on the Data Report Form, for example, line five on the P-3 form, which defines the year edition of Section I to which the boiler is constructed. That line declares that the chemical and physical properties of all the parts meet the requirements of the ASME Code, but of no specified date of issue. Thus, the manufacturer is not required to list on the Data Report Form the date of the specifications covering the pressure part material. However, the manufacturer does have to declare that the design, construction, and workmanship conform to a particular edition and addenda of Section I. Further confirmation of the above practice is found in a Section VIII interpretation that was issued on March 27, 1980, under the subject Material Usage under Section VIII, Division 1, and UG-84(b)(2), Item BC-251. One of the inquirer's questions was as follows:

Question: May material which is produced to any version of the Code be used so long as there have not been any changes made to the specification except for editorial changes?

A key paragraph in the reply was this:

Specifications to editions or addenda earlier than those in effect at the time of vessel contract may be used provided the requirements are identical (excluding editorial differences) or more stringent for the grade, class, or type produced. Material produced to earlier specifications with requirements different from the specification in effect at the time of the contract may also be used provided the material manufacturer or vessel manufacturer certifies with evidence acceptable to the Authorized Inspector that the requirements of the version in effect at the time of contract will be met.

This was a reasonable policy, since material specifications change very slowly, and there is virtually no possibility that a material proven by years of satisfactory service would suddenly be found to be unsafe. At worst, allowable stresses at elevated temperature might be reduced, but the material itself would still be

acceptable. Changes to material specifications are initiated by the American Society for Testing and Materials (ASTM) and are then usually adopted by ASME. Often, the changes are little more than an updating of some of the many other specifications and documents typically referenced in the material specifications. Occasionally, however, a new grade is added to a particular specification, or the yield strength of a particular grade may be increased slightly to make its properties and allowable stresses consistent with other similar alloys.

In the 1980s, a number of factors changed this situation. One of these was the development of improved technology, which allowed the major steel producers to produce cleaner steels with reduced maximum permissible phosphorous and sulfur content. In recognition of this advance, the ASTM reduced the maximum permissible limits on phosphorous and sulfur from 0.050% and 0.060%, respectively, to 0.035%. When the ASME adopted those changes, the Committee realized that a great deal of heretofore perfectly good material was still in inventory at material manufacturers, pressure vessel equipment manufacturers, and other users such as utilities. The prohibition of the further use of this material in inventory would have represented a huge economic penalty and could not be justified on the grounds of safety. Accordingly, the Committee decided that a gradual shift to the use of the new, cleaner steels would be appropriate and issued Code Case 2053, For Material in Inventory, Sections I, IV, and VIII, Divisions 1 and 2. The case permits continued use of material in inventory, as explained below.

Another important change that took place in the 1980s was the increasing use of imported steel. The principal source of steel for the large domestic integrated steel producers was blast-furnace product derived from raw ore. This yielded steel with a fairly consistent content of residual elements. For various reasons, perhaps because of more variable ores or a greater use of scrap material, overseas steel producers sometimes produced steel with a much higher content of certain elements, called residual elements, not usually listed in the material specifications. These residual elements affect properties such as weldability, fracture toughness, and strength levels.

An example of the problems caused by residual elements occurred at one of the authors' companies during the welding of some pipe that was thought to be carbon steel. Unexpected cracks developed in the welds, despite the fact that all the normal welding procedures were used. After a careful check of the welding variables showed nothing amiss, a spectographic examination of the pipe material showed it to contain enough chromium to change its material category from P-1 (plain carbon steel, the easiest to weld) to a low-chromium category that required preheat to assure crack-free welds. Although the pipe had been bought in Texas, it turned out that the hollow from which it was drawn had been made in Europe. At that particular time, in the late 1980s, neither the ASTM nor the ASME material specifications for carbon steel pipe had any limit for residual elements such as chromium, copper, nickel, molybdenum, and vanadium, which were not normally expected in plain carbon steel.

Another problem that occurred occasionally with the use of steel manufactured in Europe was the cracking of cold-bent carbon steel pipe after a few years of service. Studies under the sponsorship of the Material Properties Council found some evidence that the problem may have been caused by the presence of small amounts of residual elements, such as copper and tin. These elements may have come from scrap used in the manufacture of the pipe.

Owing to the welding and other problems with unexpected and unwanted residual elements in carbon steels, the ASTM (and the ASME), in the late 1980s, began a program of revising the specifications for some of these materials, to restrict their chemistry. Limits were placed on the permitted percentages of certain residual elements. For example, the current specifications for SA-53 and SA-106 carbon steel pipe call for a maximum chromium, copper, or nickel content of 0.4%, and a maximum combined total of 1% for five named residual elements. The certified material test report routinely furnished with pressure-part material lists this material composition. As a consequence of the restricted chemistry, materials manufactured to the new requirements changed slightly. Again, the problem of material in inventory was raised, since it would not be possible without expensive and tedious analysis to demonstrate that the old material met the requirements of the latest specification for residual elements. Fortunately, Code Case 2053, dealing with materials in inventory, again applied and permitted the continued use of those materials, as explained below.

It should be noted that Code Case 2053 has now been annulled, since the Committee felt that it had served its purpose and that Table ED-1 in Sections II, Parts A and B, provide sufficient information to use materials produced to earlier editions.

USE OF MATERIALS IN INVENTORY

Now that Code Case 2053 is no longer available, as explained above, how does a manufacturer use material in inventory that was produced to an earlier edition of a Material Specification? The answer is to check Table ED-1 in ASME Section II, Parts A or B, as applicable, for the particular material specification, and may use this material provided the material specification falls within the editions stated in the column *Other Acceptable ASTM Editions*. For example, a manufacturer has in stock SA-516 boiler plate produced prior to the 2006 Edition (*Latest Adopted ASTM Edition*). Reviewing Table ED-1 in Section II, Part A, under column *Other Acceptable ASTM Editions* for SA-516 is listed *86 through 06* (i.e., 1986 through 2006 editions). Also, this specification has the following note: *Identical. The reference to Footnote B in Table 1 shall apply to the -04, -05 and -05e editions*. Therefore, the manufacturer may use the material in inventory provided it was produced to an edition of the material specification 1986 or later.

CODE GUIDANCE ON THE USE OF OLD MATERIALS

In the early 1990s, the Committee on Materials, BPV II, was asked to address and provide guidance on the problem of using materials made to previous editions of the specifications. As indicated above, BPV II prepared an Appendix A (now Table ED-1) to both Parts A and B of Section II, listing the latest material specifications adopted by the ASME and the dates of earlier versions considered equivalent and acceptable, going back in some cases to 1980. The task of comparing and accepting earlier specifications was lengthy and tedious, so Subcommittee II went back only to 1988 as a base year for comparison, but listed some earlier years when it was apparent that those earlier editions were identical to the 1988 editions.

The introduction to Table ED-1 is rather brief, but it explains several important policies that differ slightly from those explained in the 1980 Section VIII interpretation mentioned above. Table ED-1 states that an ASME or an ASTM specification with requirements different from the current or other acceptable specification (e.g., the one in effect at the time of the contract) may be used, provided the material manufacturer or vessel manufacturer certifies with evidence acceptable to the Authorized Inspector that the requirements of one of the acceptable versions of the specification have been met.

There is other useful information to be found in the introduction to Table ED-1 of Section II, Parts A and B. This appendix lists the book sections of the ASME Boiler Code that approve and permit the use of the various specifications. Stated another way, it is possible to find any Section II material in Table ED-1 in a numerical list and quickly determine which book sections permit its use. Table ED-1 also states that a material produced under an ASTM specification may be used in lieu of the corresponding ASME specification listed in Table ED-1 (if it is identical). If it is not identical, the manufacturer would have to demonstrate to the AI that the ASTM material met the requirements of the corresponding ASME specification. A situation illustrating many of the problems that can arise when using old material happened at one of the authors' companies. That company had in inventory a considerable quantity of SA-178 grade C tubing material from a job that had been cancelled in 1985 and decided to use it for a boiler being built to the 1995 edition of Section I. When the old tubes were shipped from one of the company's plants to another, they were challenged by the receiving plant's quality control inspectors because the list of acceptable specifications in Table ED-1 of Section II, Part A went back only as far as the 1989 SA-178 specification.

Upon careful review of the 1985 and 1995 specifications, it was found that a number of requirements had been deleted in the 1995 version, and the permitted chemistry ranges for sulfur and phosphorous had been reduced to 0.035% from the 1985 values of 0.060% and 0.050%, respectively. The certified material test

reports for the old tubes showed that the sulfur content was just over the new 0.035% limit for at least some of the tubes. Thus, it would not be possible to demonstrate that the old material met the requirements of one of the currently acceptable versions of the SA-178 specification listed in Appendix A. Moreover, if the old tubes could not be used, new ones would have to be purchased, and the job would suffer costly delay. Fortunately, Code Case 2053, dealing with materials in inventory, was written to provide relief for just this sort of situation. When Case 2053 was brought to the attention of the QC inspector, he dropped all further objections to the use of the old tubes.

A caveat should be offered here. Code Cases have a limited life. Code Case 2053 was intended to relieve economic hardship and allow old material in inventory to be used up. It is unlikely that the case will ever be incorporated into the text of the Code, and there is some sentiment among the Committee members to let it expire, on the grounds that sufficient time has been allowed to exhaust the old stocks of material. As indicated above, Code Case 2053 has been annulled, and the provisions of Table ED-1 of Section II, Parts A and B should cover most cases where a manufacturer wishes to use material in inventory, and which was produced to an edition earlier than current edition.

BOILER DESIGN

DESIGN LIFE

The Foreword to Section I states that the objective of the rules is to afford reasonable protection of life and property and to provide a margin for deterioration in service so as to give a reasonably long safe period of usefulness. Just how long is that period? There are many 40-year-old boilers that are still giving good service, and sometimes, 40 years is cited as the expected life of a boiler, assuming of course that it is properly maintained. However, Section I gives no explicit indication of what constitutes a reasonably long design life. Sometimes, the criteria used to establish allowable design stresses at elevated temperature are mistakenly assumed to imply a limited design life of only 100,000 hr (about 14 yr if the boiler is in service 80% of the time). These criteria are found in paragraph 1-100(b) of Appendix 1 of Section II, Part D, from which the following excerpt is taken:

At temperatures in the range where creep and stress rupture strength govern the selection of stresses, the maximum allowable stress value for all materials is established by the Committee not to exceed the lowest of the following:

- (1) 100% of the average stress to produce a creep rate of 0.01 %/1000 hr.*
- (2) 67% of the average stress to cause rupture at the end of 100,000 hr.*
- (3) 80% of the minimum stress to cause rupture at the end of 100,000 hr.*

The criterion that usually governs is the second, 67% of the average stress to cause creep rupture at the end of 100,000 hr of service. Note that this stress is not one that would cause creep rupture after 100,000 hr of service; it is only 67% of that stress. Creep life (i.e., the time it takes to cause creep rupture in elevated temperature service) is a complex nonlinear function of stress and temperature. By experiment and analysis, the relationship among temperature, stress, and time to creep rupture has been established and plotted as a series of creep rupture curves. These are log stress versus log time curves, with temperature as a parameter. When plotted this way, the “curves” are almost straight lines (see Fig. 14.2 in Chapter 14: Creep and Fatigue Damage During Boiler Life).

A review of creep rupture curves for typical steels used in boiler construction shows that for a given temperature, a one-third reduction in stress results in an increase in creep life (time to stress rupture) by a factor approaching 10. Thus, if the allowable stress is chosen as two-thirds (67%) of the average stress to cause rupture in 100,000 hr, the actual time to rupture will be far greater, perhaps approaching 1,000,000 hr. Such a time is considerably greater than the 40-yr design life sometimes cited for boilers, which represents less than 300,000 hr for a boiler assumed to be in service 80% of the time. This estimate is confirmed by experience, which shows that boilers and pressure vessels designed using the ASME Code have very long safe lives.

Two inquiries on the design life of boilers have been answered in recent years. The first of these was Interpretation I-89-30, under the heading Section I, Basis for Establishing Allowable Stress Values:

Question: *Does the ASME Boiler and Pressure Vessel Committee establish a specific design life for components designed to Section I?*

Reply: *No.*

A similar but more elaborate version of the same question, posed by a foreign manufacturer, was answered in March 1996 by BPV II, the Standards Committee on Materials. That Interpretation was published with the second group of 1997 Interpretations, as IID-95-01:

Question: *Do the criteria of Appendix 1 of Section II, Part D, for establishing stress values in Tables 1A and 1B, imply an explicit design life for Section I construction, using the allowable stresses in Tables 1A and 1B for materials permitted for Section I construction?*

Reply: *No. There is neither an explicit nor an implicit design life associated with the allowable stresses in Tables 1A and 1B for Section I construction. The criteria of Appendix 1 of Section II, Part D, have been established with the intention that sufficient margin is provided in the allowable stresses to preclude failure during normal operation for any reasonable life of boilers constructed according to Section I rules.*

It is probably appropriate to add a final comment that is based on committee discussion but was excluded from the above interpretation because it deals with matters that are clearly beyond new construction. The committee's response was worded with the understanding that boilers are subject to periodic inspections. These inspections provide reasonable assurance of finding and repairing areas that may have become damaged due to erosion, corrosion, or other wastage phenomena or due to any unexpected operating conditions that may have reduced the wall thickness or load-carrying capability of particular components.

DESIGN ALLOWABLE STRESSES

The design allowable stresses for all materials permitted for Section I construction are listed in Section II, Part D for the selected material design metal temperature. In the time-independent region, generally 700°F (370°C) for ferritic materials, the allowable stress is set as a percentage of the minimum tensile stress for the particular material at the selected design temperature. Prior to 1998, the design allowable stress in the time-independent region was based on the material's minimum tensile strength divided by four. In the late 1990s, the ASME Boiler and Pressure Vessel Committee came to realize that components fabricated to their Code could not compete with similar products to other Codes (i.e., European Standards).

Subsequently, the Committee voted to modify the basis for establishing the allowable stresses in the time-independent temperature range to the material's minimum tensile strength divided by three and a half. This resulted in an increase of the allowable stress by about 14%. By the time the necessary changes to Section II, Part D were ready, it was too late to meet the publication date for the next Code edition (1998 Edition); so to permit early implementation of this change, a Code Case was issued in the summer of 1998. This new Code Case caused some controversy, particularly since some jurisdictions did not permit Code Cases. Subsequently, this Code Case was incorporated into Section I, and Section VIII, Division 1 in the 1999 Addenda.

The allowable stresses in the time-dependent temperature region were not changed, since the criteria used to establish these allowable stresses remained as it was prior to the change indicated above, and is as shown in the above section entitled DESIGN LIFE.

DESIGN METHODS

For the most part, Section I uses an experience-based design method known as design-by-rule. (Certain other sections of the Code, namely, Section III and Section VIII, Division 2, use a newer method, known as design-by-analysis.) Design-by-rule is typically a process requiring the determination of loads, the choice of a design formula, and the selection of an appropriate design stress for the material to be used. Rules for

this kind of design are found throughout Section I, with most being in Part PG (the general rules). Other design rules are found in those parts of Section I dealing with specific types of boilers or particular types of construction.

The principal design rules are found in PG-16 through PG-55. There are formulas for the design of cylindrical components under internal pressure (tube, pipe, headers, drums), heads (dished, flat, stayed, and unstayed), stayed surfaces, and ligaments between holes. Rules are also provided for openings or penetrations in any of these components, based on a system of compensation in which the material removed for the opening is replaced by reinforcing the region immediately around the opening. All of these formulas involve internal pressure, except the rules for support and attachment lugs of PG-55, for which the designer chooses the design loads on the basis of the anticipated weight or other loads to be carried. The one exception to the above is that some components of firetube boilers are designed for external pressure, see PFT-51 for design formulas. These various design topics are discussed later in this chapter.

Another method of design permitted by Section I is a hydrostatic deformation or proof test (PG-18, Appendix A-22). An experience-based method, it is used to establish a safe design pressure for components for which no rules are given or when strength cannot be calculated with a satisfactory assurance of accuracy. In this type of proof test, a full-size prototype of the pressure part is carefully subjected to a slowly increasing hydrostatic pressure until yielding or bursting occurs (depending on which type of test it is). The maximum allowable working pressure (the design pressure; see definition under Design Loads, below) is then established by an appropriate formula, including the strength of the material and a suitable safety factor. Proof testing may not be used if Section I has design rules for the component, and in actual practice, such testing is seldom employed. However, it can be a simple and effective way of establishing an acceptable design pressure for unusual designs, odd shapes, or special features that would be difficult and costly to analyse, even with the latest computer-based methods. The use of proof testing used to be common for the design of marine boiler headers of D-shaped or square cross-section.

Tests which are used to establish the maximum allowable working pressure of pressure parts must be witnessed and approved by the Authorized Inspector, as required by Appendix A-22.10. The test report becomes a permanent reference to justify the design of such parts should the manufacturer want to use that design again for other boilers.

DESIGN LOADS

When Section I was written, its authors understood so well that the internal working pressure of the boiler was the design loading of overriding importance that virtually no other loading was mentioned. To this day, there is very little discussion of any other kind of loading, except for PG-22, which merely cautions that other loads causing stresses greater than 10% of the allowable stress shall be taken into account. Because internal pressure is the principal loading of concern, it appears in all Section I design formulas. The pressure inside the pressure parts of the boiler is called the working pressure. For design purposes, Section I uses the term **maximum allowable working pressure**, or MAWP, to define what engineers usually understand to mean design pressure.

There are many other loads on a boiler in addition to pressure. Among these loads are the weight of the boiler and its contents, seismic loads, wind loads, and thermal loads. Section I has no provisions specifically dealing with the last three, but it is the responsibility of the designer to consider them. As boiler designs evolved over the years, the manufacturers have recognized and made provision for these loads.

Recently, as nuclear plants have assumed more of the utilities' base load, fossil-fired boilers are increasingly being used in cyclic service, with frequent start-ups and shutdowns. This type of operation has the potential for causing repeated, relatively high transient thermal stress and may require careful analysis for fatigue and creep damage. Although Section I has successfully considered creep and creep rupture in setting allowable stresses, it has no specific rules for creep-fatigue interaction or even for simple fatigue. Nevertheless, consideration of this phenomenon remains the responsibility of the manufacturer. As discussed in

Chapter 14, elevated-temperature design for fatigue and creep is a complex subject, for which no complete rules have yet been developed. Such Code rules as are available appear in Section III, Subsection NH, Class 1 Components in Elevated Temperature Service. Subsection NH is based on Code Case N-47, which dealt with nuclear power plant components in elevated-temperature service. The earliest version of Case N-47 dates back to the late 1960s. Elevated-temperature service means service above that temperature at which creep effects become significant. This threshold is usually taken as 700°F (370°C) for many ferritic materials (carbon and low alloy materials) and 800°F (425°C) or higher for austenitic materials (the high alloy materials such as stainless steel). With the exception of parts of superheaters, most boilers are made of ferritic materials.

Weld Joint Strength Reduction Factor

With the 2008 Addenda, PG-26 was added to Section I. PG-26 states in part “At elevated temperatures, the long-term strength of weld joints can be lower than the long-term strength of the base material. Table PG-26 (reproduced here for ready reference) specifies a weld strength reduction factor, w , to be used to account for the lower long-term strength in determining the required thickness of components operating in the creep range”.

When applying the requirements of Table PG-26 WELD STRENGTH REDUCTION FACTORS TO BE APPLIED WHEN CALCULATING MAXIMUM ALLOWABLE WORKING PRESSURE OR MINIMUM REQUIRED THICKNESS OF COMPONENTS FABRICATED WITH A LONGITUDINAL SEAM WELD, the designer should review the “Notes” applicable to this table.

Note that the weld strength reduction factor is not applicable to any material having a maximum design temperature of 800°F (425°C) or less (may be higher for some materials). Also, note that PG-26 and Table PG-26 is not applicable to carbon steel pipe and tubes (Note 3).

Choice of Design Pressure and Temperature

Section I does not tell the designer what the design pressure (MAWP) and design temperature of a boiler should be. These design conditions must be chosen by the manufacturer or specified by an architect-engineer, user, or others. In most instances, Section I requires only the MAWP, not the design temperature, to be stamped on the boiler. (When discussing design temperature, it is necessary to distinguish between metal temperatures and steam temperatures, either of which may vary within the boiler.) As a practical matter, the designer must know and choose an appropriate design (metal) temperature for each element of the boiler because the allowable stress values are based on these temperatures. In many cases, the design temperature of an individual element such as a superheater tube may be much higher than the design steam temperature of the boiler. This stems from the fact that the metal temperature of a heated tube is always higher than that of the steam within and from the need to provide a design margin for potential upsets in gage temperature or steam flow.

In a natural circulation boiler, most of the pressure parts are designed for the MAWP. However, slightly different design pressures are used for some components, since PG-22 stipulates that hydrostatic head shall be taken into account in determining the minimum thickness required, “unless noted otherwise.” The formulas for determining the thickness of cylindrical components under internal pressure found in PG-27 are of two types: one applicable to “tubing-up to and including 5-in. (125-mm) outside diameter,” and the other applicable to “piping, drums, and headers.” Having only these two categories of design formula sometimes puzzles inexperienced designers, who are not sure which formula to use for tubing larger than 5-in. (125-mm) outside diameter. They soon learn the accepted practice for such tubing, which (by the process of elimination) is to use the formula for “piping, drums, and headers.” The two types of wall thickness formulas have other differences worth noting, as they are a source of confusion to designers and have led to quite a number of inquiries to BPV I.

TEMPERATURE, °F	700	750	800	850	900	950	1,000	1,050	1,100	1,150	1,200	1,250	1,300	1,350	1,400	1,450	1,500
TEMPERATURE, °C	371	399	427	454	482	510	538	566	593	621	649	677	704	732	760	788	816
STEEL GROUP	WELD STRENGTH REDUCTION FACTOR [NOTES (1)–(6)]																
C-Mo [Note (7)]	...	...	1.00	NP	NP	NP	NP	NP	NP	NP	NP	NP	NP	NP	NP	NP	NP
Cr-Mo [Notes (8), (9)]	...	...	1.00	0.95	0.91	0.86	0.82	0.77	0.73	0.68	0.64	NP	NP	NP	NP	NP	NP
CSEF (N+T) [Notes (9)–(11)]	...	...	...	...	...	1.00	0.95	0.91	0.86	0.82	0.77	NP	NP	NP	NP	NP	NP
CSEF (subcrit.) [Notes (9), (12)]	...	...	...	...	1.00	0.50	0.50	0.50	0.50	0.50	0.50	NP	NP	NP	NP	NP	NP
Austenitic stainless steels and alloys 800H (N08800) and 800HT (N08810) [Notes (13), (14)]	...	...	...	...	...	1.00	0.95	0.91	0.86	0.82	0.77	0.73	0.68	0.64	0.59	0.55	0.50
Autogenously welded austenitic stainless [Note (15)]	...	...	...	...	...	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

GENERAL NOTE:

Nothing in this table shall be construed to permit materials that are not permitted by PG-5 through PG-9 of this Section or to permit use of materials at temperatures beyond limitations established by this Section. Several materials covered by this table are currently permitted for Section I only at via code case.

NOTES:

- (1) Cautionary Note: There are many factors that may affect the life of a welded joint at elevated temperature, and all of those factors cannot be addressed in a table of weld strength reduction factors. For example, fabrication issues such as the deviation from a true circular form in pipe (e.g., "peaking" at longitudinal weld seams) or offset at the weld joint can cause an increase in stress that may result in reduced service life, and control of these deviations is recommended.
- (2) NP = not permitted.
- (3) Components made from carbon steel are exempt from the requirements of PG-26 and Table PG-26.
- (4) Longitudinal seam welds in components made from materials not covered in this table operating in the creep regime are not permitted. For the purposes of this table, the creep regime temperature range is defined to begin at a temperature 50°F (25°C) below the T-note temperature listed in Section II, Part D design property tables for the base material involved.
- (5) All weld filler metal shall have a minimum carbon content of 0.05% for the Cr-Mo and CSEF materials and a minimum carbon content of 0.04% for the austenitic stainless steels.
- (6) At temperatures below those where WSRFs are tabulated, a value of 1.0 shall be used for the factor ω where required by the rules of this Section; however, the additional rules of this table and notes do not apply.
- (7) Longitudinal seam fusion welded construction is not permitted for C-½Mo steel above 850°F (454°C).
- (8) The Cr-Mo steels include ½Cr-½Mo, 1Cr-½Mo-Si, 2¼Cr-1Mo, 3Cr-1Mo, and 5Cr-½Mo. Longitudinal welds shall either be normalized, normalized and tempered, or subjected to proper subcritical PWHT for the alloy.
- (9) Basicity index of SAW flux ≥ 1.0 .
- (10) N + T = normalizing + tempering PWHT.

TABLE PG-26
WELD STRENGTH REDUCTION FACTORS TO BE APPLIED WHEN CALCULATING MAXIMUM ALLOWABLE WORKING PRESSURE OR MINIMUM REQUIRED THICKNESS OF COMPONENTS FABRICATED WITH A LONGITUDINAL SEAM WELD

- (11) The CSEF (creep strength enhanced ferritic) steels include Grades 91, 92, 911, 122, and 23.
- (12) subcrit. = subcritical PWHT is required. No exemptions from PWHT are permitted. The PWHT time and temperature shall meet the requirements of Table PW-39; the alternative PWHT requirements of Table PW-39.1 are not permitted.
- (13) Certain heats of the austenitic stainless steels, particularly for those grades whose creep strength is enhanced by the precipitation of temper-resistant carbides and carbo-nitrides, can suffer from an embrittlement condition in the weld heat-affected zone that can lead to premature failure of welded components operating at elevated temperatures. A solution annealing heat treatment of the weld area mitigates this susceptibility.
- (14) Alternatively, the following factors may be used as the weld joint strength reduction factor for the materials and welding consumables specified, provided the weldment is solution annealed after welding.

		Weld Strength Reduction Factor												
Materials		950	1,000	1,050	1,100	1,150	1,200	1,250	1,300	1,350	1,400	1,450	1,500	
Temperature, °F		510	538	566	593	621	649	677	704	732	760	788	816	
Temperature, °C														
Type 304 stainless welded with														
SFA-5.22 EXXXT-G (16-8-2 chemistry),														
SFA 5.4E 16-8-2, and SFA-5.9 ER 16-8-2														
		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00					
Type 316 stainless welded with														
SFA-5.22 EXXXT-G (16-8-2 chemistry),														
SFA 5.4E 16-8-2, and SFA-5.9 ER 16-8-2														
		1.00	0.85	0.90	0.97	0.99	1.00							

- (15) Autogenous welds (without weld filler metal) in austenitic SS materials have been assigned a WSRF of 1.00 up 1,500°F (816°C), provided that the product is solution annealed after welding and receives nondestructive electric examination, in accordance with the material specification.

TABLE PG-26
WELD STRENGTH REDUCTION FACTORS TO BE APPLIED WHEN CALCULATING MAXIMUM ALLOWABLE WORKING PRESSURE OR MINIMUM REQUIRED THICKNESS OF COMPONENTS FABRICATED WITH A LONGITUDINAL SEAM WELD (CONT'D)

Alternative Equation for Calculating the Minimum Thickness of Cylindrical Components (Appendix A-317)

The late John Fishburn, a long time member of BPV I, as well as several of its Subgroups, was considered to be the Committee's guru of mathematics. John developed the equations in Appendix A-317, which may be used to calculate the required thickness of or the maximum allowable working pressure of piping, tubes, drums and headers in lieu of using the equations given in PG-27. Since these equations cover both tubes and piping, there is no ambiguity about which equation to use, as indicated above with respect to the equations in PG-27.

Appendix A-317 was added to Section I of the ASME Boiler and Pressure Vessel Code in the 2007 Edition and may be used as permitted in PG-27.1.

Avoidance of Thermal Shock

Experience has shown that pressure parts may experience thermal fatigue damage if cooler feedwater is introduced in such a way that it impinges on the walls of a hot vessel. PG-59.2 addresses this problem by prohibiting the direct discharge of feedwater against vessel surfaces exposed to high-temperature gases or radiation from the fire. Moreover, for pressures over 400 psi (3 MPa), a device such as a thermal sleeve or shield is required on the feedwater inlet through the drum, to protect local areas of heads and shells from excessive temperature differentials; the latter can cause significant cyclic thermal stress and potentially lead to fatigue cracking.

Hydrostatic Test

Prior to the changes in the allowable stresses in 1998, the standard hydrostatic test ($1\frac{1}{2} \times \text{MAWP}$) was not a concern for the designer. With increase in allowable stresses in the time-independent temperature, it was necessary to change the requirements for the Hydrostatic Test. In this respect, Sections I and VIII took different routes. Section VIII decided to lower the Hydrostatic Test pressure to 1.25 times the Maximum Allowable Working Pressure (MAWP). Section I decided to retain their existing requirement of 1.5 times MAWP. In doing so, Section I added a new requirement that the general membrane stress of any component shall not exceed 90% of the material's yield strength (2% offset) at test temperature (PG-99.1).

It would appear from the above that the Section VIII hydrostatic test requirements are less conservative than those of Section I. This is not necessarily the case, since Section VIII requires the Manufacturer to multiply his calculated hydrostatic test pressure (1.25 times MAWP) by the Code allowable stress at test temperature divided by the Code allowable stress at design temperature. In some cases, this would result in a higher test pressure than that of a Section I component having the same material and same MAWP.

The designer is responsible to take into account the hydrostatic test condition. For most materials commonly used in the construction of Section I components, this is not normally a problem, since the hydrostatic test condition will not govern. However, if materials are used, which have a minimum yield strength of less than half the minimum tensile strength of that material, the designer may be required to make that component's minimum thickness greater to suit the hydrostatic test condition.

Hydrostatic Head

The tubing design formula refers to Note 10, which states that the hydrostatic head need not be included when this formula is used. Thus, the design pressure, P , is taken as just the MAWP for all tubes 5-in. (125-mm) OD and under. The term $0.005D$ in the tube design formula was added by BPV I when the current version of the tube design formula was adopted in the 1960s. The new formula initially proposed at that time gave somewhat thinner walls than the previous formula, leading to a concern on the part of some committee members that tubes for low-pressure boilers would lack adequate strength to sustain any occasional mechanical loading

to which they might be subjected. The $0.005D$ term was a compromise value selected by the committee in response to this concern, to provide a little extra strength in the tubes. No similar note excluding consideration of hydrostatic head applies to the design formulas for piping, drums, and headers. Accordingly, the design pressure, P , used in those formulas must include the hydrostatic head, which on a large utility boiler could add as much as 50 psi (350 kPa) to the MAWP for a lower waterwall header or a downcomer, since the height of such units may equal that of a 15-story building. Of course, the additional hydrostatic head would be much less for a header near the top of the boiler, such as a roof-outlet header. Incidentally, it is traditional to measure hydrostatic head from the elevation of the drum centerline, since that is the normal water line.

The exclusion of hydrostatic head in the tube design formula, but not in the pipe design formula, came about from the adoption of slightly different formulas. The formula for tubing had evolved for equipment of modest height, where hydrostatic head was considered negligible; in contrast, it was thought necessary to include hydrostatic head in the formula for piping. This arbitrarily different treatment of hydrostatic head has little significance in most practical instances. A much larger potential difference in wall thickness for pipe versus tube results from a number of factors prescribed by PG-27 to account for the effects of expanding tubes, threading pipe, or the need for structural stability.

Other Factors Applicable to Tube and Pipe Design

The first of these several factors is e , defined as a thickness factor for expanded tube ends that is applied to tubes below certain minimum sizes. Note 4 of PG-27.4 lists e values required for various sizes of tubes. The thickness factor is an extra 0.04-in. (1.0-mm) thickness required over “the length of the seat plus 1 in. (25 mm) for tubes expanded into tube seats.” This provides a slightly heavier wall for that portion of the tube that is rolled, or expanded, into the tube hole. In the rolling process, the tube undergoes considerable cold working and some thinning, and the extra 40 mils (1.0 mm) of wall thickness is intended to assure a sound joint no weaker than the unexpanded portion of the tube. This extra 40 mils (1.0 mm) applies only to very thin tubes, as stipulated in Note 4. Such tubes are usually used only for relatively low-pressure boilers.

Another of these factors is C , described as a “minimum allowance for threading and structural stability.” It is intended for application to pipe, but as will be explained later, it can sometimes also apply to tubes. When used as a threading allowance, C provides extra wall thickness to make up for material lost in threading. For threaded pipe, Note 3 of PG-27.4 stipulates a C value of 0.065 in. (1.65 mm) for pipe NPS $\frac{3}{4}$ (DN 20) and smaller and a C value equal to the depth of the thread for pipe NPS 1 (DN 25) and larger. For unthreaded pipe, an extra wall thickness of 0.065 in. (1.65 mm), called an **allowance for structural stability**, must be provided for pipe smaller than NPS 4 (DN 100). This allowance is traditionally explained to new members of BPV I as having been chosen to provide sufficient bending resistance in the smaller size pipes to withstand loads imposed by a 200-lb (90-kg) worker on a ladder leaning against the middle of a 10-ft (3.0-m) span of pipe to do some maintenance on the boiler. The larger size pipes presumably are strong enough to take care of themselves under such occasional mechanical loads. While the worker on the ladder story may not be exactly true, the effect of these several factors is to strengthen the tubes and pipes of very low-pressure boilers, whose walls might otherwise be so thin that the boiler would be too flimsy to resist any occasional mechanical loads. However, Note 3 of PG-27.4 makes clear that the allowances for threading and structural stability are not intended to provide for conditions of misapplied external loads or for mechanical abuse.

DISTINCTION BETWEEN BOILER PROPER PIPING AND BOILER EXTERNAL PIPING

For many years, Section I made no distinction regarding the piping of a boiler; all of it was just treated as piping. In the late 1960s, some members of the committee decided that the piping rules of Section I were no longer adequate to cover the design of modern high-pressure, high-temperature, steam piping. After due consideration, it was decided to divide all piping within the scope of Section I into two categories. The piping

that was actually part of the boiler (such as downcomers, risers, transfer piping, and piping between the drum and an attached superheater) was designated as **boiler proper piping**. Construction rules for this piping were retained in Section I. The piping that led to or from the boiler (such as feedwater, main steam, vent, drain, blowoff, chemical feed piping) was designated a new category, **boiler external piping**, an appropriate name, since it is usually external to the boiler. This piping was defined by its extent: from the boiler to the valve or valves required by Section I (the boundary of the boiler). These valves also were defined as part of the boiler external piping. In 1972, responsibility for most aspects of the construction of this piping was transferred from Section I to the Power Piping Code, ASME B31.1. That is, rules for material, design, fabrication, installation, and testing of boiler external piping were now contained in B31.1, but Section I retained its usual certification requirements (with Authorized Inspection and stamping).

To clarify the distinction between the two categories of piping, BPV I expanded Fig. PG-58.3.1 to show each category. A comparable figure appears in the front of B31.1. Within B31.1, still another new category of piping then had to be established, called **nonboiler external piping**, i.e., the piping beyond the scope of Section I that is connected to the boiler external piping. Figure PG-58.3.1 is reproduced in Chapter 5.

Transferring coverage of the boiler external piping to B31.1 made available, at a stroke, detailed and comprehensive rules not provided by Section I for such important aspects of piping design as flexibility analysis and hanger design. By retaining complete coverage of boiler proper piping, Section I continued its policy of providing minimal guidance in the design of this piping, which has traditionally been left to the boiler manufacturer.

There have been some negative consequences of the transfer of the design of boiler external piping to B31.1. For one thing, an entirely different committee governs the Power Piping Code. Inquiries about boiler external piping typically are answered by that committee, and occasional differences develop between the B31.1 Section Committee and BPV I. In the early 1990s, this problem was apparently resolved by an action of the Board of Pressure Technology Codes and Standards, which reaffirmed B31.1's primary responsibility for the rules governing the design of boiler external piping. Also, despite the best efforts of both committees, minor differences that exist between the respective rules result in different treatment of piping on the same boiler, depending on whether it is boiler external piping or boiler proper piping (e.g., requirements for postweld heat treatment and radiography differ for the two categories of piping). While both sets of rules are doubtless more than adequate, unwary designers who do not pay sufficient attention to what type of piping they are designing can run into expensive delays should an Authorized Inspector notice at the last minute that the piping does not meet the appropriate rules. Further discussion of piping design is found in Chapter 5.

SOME DESIGN DIFFERENCES: SECTION I VERSUS B31.1

As explained in the previous section, design rules for boiler external piping are found in ASME B31.1, Power Piping. The formula for the design of straight pipe under internal pressure in 104.1 of B31.1 looks the same as the design formula for piping, drums, and headers in PG-27.2.2 of Section I, except that the additive term *C* of Section I is called *A* in B31.1. In either case (*A* or *C*), the intention is to account for material removed in threading, provide some minimum level of mechanical strength, and, if needed, provide an allowance for corrosion or erosion. There are, however, some slight differences between Section I and B31.1 that should be mentioned, since occasionally, designers forget that certain piping — e.g., piping from the drum to water-level indicators or vent and drain piping — is boiler external piping for which B31.1 rules apply. Unlike Section I, B31.1 does not mandate a specific 0.065-in. (1.5-mm) extra thickness for mechanical strength or structural stability of plain end pipes smaller than NPS 4 (DN 100). Rather, B31.1, 102.4.4 recommends an increase in wall thickness where necessary for mechanical strength or, alternatively, requires the use of design methods to reduce or eliminate superimposed mechanical loading. Thus, B31.1 gives the designer a choice: provide some (unspecified) increase in wall thickness or take measures to limit mechanical loads. In either case, the details are left to the judgment of the designer. Also, according to 104.1.2(C) of B31.1, pipe used for service above certain pressures or temperatures must be at least schedule 80 pipe. This paragraph is similar to Section I's PG-27.4.5 Note 5.

BEND DESIGN

Another difference in the design of piping according to Section I versus B31.1 is in their respective treatment of bends. The B31.1 rule, found in 102.4.5, is that the minimum wall thickness at any point in a bend must not be less than that required for the equivalent straight pipe. Ordinary bending methods usually result in some thinning of the wall on the outside of bends and some thickening on the inside. Consequently, under the B31.1 rule, a bend thinning allowance must be added to the wall of a straight pipe so that the finished bend will meet the required minimum thickness. Table 102.4.5 of B31.1 provides recommendations for minimum thickness prior to bending, as a function of the radius of the pipe bend. If good shop practices are followed, these allowances should result in bends of the required minimum thickness. Section I has no similar rule, and over the years, quite a few inquiries have been received asking for guidance on this subject. Before the advent of published Interpretations in January 1977, BPV I responded to questions by a letter known as an “unofficial communication.” Since 1977, committee responses have been published as Interpretations, as explained in the Introduction and Appendix II. Section I’s design approach to bends, for both pipe and tube, is explained in Interpretation I-83-23, a composite of earlier informal replies. Since the acceptance of pipe or tube bends by the Authorized Inspector as meeting the rules of either Section I or B31.1 is crucial to the timely completion of the boiler, the designer should always be aware of which rules apply. Here is Interpretation I-83-23:

Question: What rules does Section I impose with respect to wall thinning and flattening of bends in boiler tubing?

Reply: Section I does not provide specific rules directly applicable to wall thinning and flattening of bends in boiler tubing. However, the Subcommittee on Power Boilers intends that the manufacturer shall select a combination of thickness and configuration such that the strength of the bend under internal pressure will at least equal the minimum strength required for the straight tube connected to the bend.

The Subcommittee on Power Boilers’ position, based on many years of service experience, has been that thinning and flattening of tube bends are permissible within limits established by the manufacturer, based upon proof testing.

To understand the reason for the difference in design approach used by B31.1 and Section I for bends, remember that BPV I has always recognized satisfactory experience as an acceptable basis for design. When the issue of the wall thickness of tube and pipe bends was raised in the late 1960s, the committee had available a long record of satisfactory experience to justify the design approach traditionally used for bends by the major boiler manufacturers. There are, however, further arguments to support such an approach. First, bends are components with two directions of curvature, having inherently greater strength than straight pipe, which has only one direction of curvature. Second, a pipe bend resembles a portion of a torus. Membrane stresses in a torus happen to be lower on the outside diameter than on the inside, so the change in wall thickness from bending a straight pipe tends to put the material just where it is needed. Third, the bending process usually increases the yield strength of the metal by work hardening. Unless the bend is subsequently annealed, it retains this extra strength in service. When bends are proof tested to failure, they typically fail in the straight portion, not in the bend, showing that the bend is stronger. This is the basis on which Section I accepts them. It is also true that bends in Section I tubes and pipe are more likely to be within the setting of the boiler, where there is less chance that a bend failure would be dangerous to people.

Interchanging Pipe and Tube

As explained above, Section I’s two different design formulas for tubes and pipe mandate the addition of various wall thickness allowances. Over the years, a number of designers have realized that using the tube formula to design pipe, or vice versa, or substituting one of these product forms for the other might provide more economical construction. For example, if a pipe is available at a cost lower than the equivalent tube,

why not use the pipe if it satisfies the tube formula? The next question then is whether it would still be necessary to add the 0.065-in. (1.65-mm) wall thickness allowance required by the pipe design formula for mechanical stability. BPV I decided that in doing the work of tubes, pipe need only meet the thickness requirements of the tube formula, since tubes are generally within an enclosure, and there is less likelihood that the 200-lb (90-kg) worker mentioned earlier would be leaning a ladder against the middle of a 10-ft (3-m) tube span. Looked at another way, this approach appeals to common sense: if a heat-transfer tube designed by the tube formula requires a certain wall thickness and some pipe size provides the necessary thickness, the pipe has the required strength. The fact that it is a different product form should not matter. Conversely, if tubing was used as pipe, it would require the addition of any wall thickness allowances called for by the piping design formula. One note of caution, however: pipe and tube typically come in different sizes and have different manufacturing tolerances on the wall thickness; these differences must be recognized to assure that the required design thickness is obtained.

Over the years, BPV I has received quite a few inquiries on the subject of pipe versus tube and on which formulas could be used. Having in mind the experience and rationale just described, the committee twice issued an interpretation in response to the following two, related, questions. The first, on the definition of pipe and tube, was issued in 1979, but by an oversight was not published until 1983 as Interpretation I-83-47. The second was issued in 1986 as I-86-25 on the subject of wall thickness of pipe and tube.

Question: *Do the rules of PG-27.2.2 define tubing and piping, respectively, by size only, or are there other criteria?*

Question: *Under what circumstances do the equations under PG-27.2.1 (for tubing) and PG-27.2.2 (for piping) apply?*

The two replies were essentially the same. This is the 1986 reply:

Reply: *The formulas in ASME Section I, PG-27.2.1, for tubing, are intended primarily for applications such as boiler tubes, superheater and reheater tubes, or economizer tubes in which groups of such tubular elements are arranged within some enclosure for the purpose of transferring heat to or from the fluid within the tubes. For this heat-transfer function, the tubular elements ordinarily do not need fittings or valves.*

When the function to be performed is mainly the conveying of a pressurized fluid from one location to another, with little or no intentional heat transfer, the formulas in PG-27.2.2 should be used. The elements commonly used for this purpose are called piping. The standard piping sizes are available with matching sizes of fittings (tees, elbows, etc.) and valves to facilitate the installation of piping systems to direct and control the flow.

While this reply does not explicitly say that tubes and pipe may be designed using either formula, that is its intent. A close reading shows that the choice of formula is not mandatory, that the formulas for tubing are intended primarily (but not exclusively) for such applications as boiler tubes, etc. Similarly, the second paragraph, in explaining what piping does, notes only that the piping formulas should (not shall) be used. In Code language, **shall** is construed as mandatory, **should** is nonmandatory.

Another source of confusion that has elicited inquiries to BPV I is the question of where should any thickness allowance be added to pipe (i.e., on the inside surface or the outside surface, or perhaps both). Unless the proper assumptions are made, the two pipe design formulas in PG-27.2.2, one in terms of inside radius, R , and the other in terms of outside diameter, D , will give different results. The advice in Note 3 of PG-27.4 was added in the early 1980s to address this problem, but the confusion persists. At the December 1996 BPV I meeting, in response to still another inquiry on this subject, the committee approved the following question and reply, which were published as I-95-35 in the 1997 Interpretations:

Question: *The equations of PG-27.2.2 are presented in terms of either outside diameter, D , or inside radius, R . There appears to be a discrepancy between the two formulas. If the equivalent of $(2R + 2t)$ is substituted into the diameter-based formula, the radius-based formula cannot be*

derived from the results. Are the formulas of PG-27.2.2 based on radius and diameter correct and consistent with each other?

Reply: Your attention is directed to the last sentence of the first paragraph of Note 3 in PG-27.2.4. Evaluating the formulas in PG-27.2.2, using either a diameter or radius which has been adjusted by an amount equal to that part of C which is being applied to the outside diameter or inside radius will result in correct and consistent values for maximum allowable working pressure.

Corrosion/Erosion Allowance

Section I notes in PG-27.4.3, Note 3 that the design formulas do not include any allowance for corrosion and/or erosion and that additional thickness should be provided where they are expected. Thus, the designer is given the responsibility for deciding whether such allowances are needed and, if so, their amount and location.

U.S. boiler manufacturers do not normally add a corrosion or erosion allowance when calculating the design thickness of boiler pressure parts. Experience has shown such allowances to be unnecessary under normal service conditions. Ordinarily, the boiler water treatment controls oxygen levels, dissolved solids, and pH so that corrosion on the waterside is insignificant. Similarly, fireside corrosion has not generally been a problem, except under unusual circumstances attributable to certain temperature ranges and some particularly corrosive constituents in the fuel. Even in these cases, it is not usually practical to solve the problem by a corrosion allowance. In the unusual circumstance of severe local corrosion or erosion, any extra wall thickness allowance might at best serve to prolong component life for only a short time. Furthermore, extra thickness added to the wall of a heated tube raises the temperature of the outside surface, tending to increase the rate of corrosion. Some other solution to the problem is usually necessary, such as elimination of the corrosive condition, a change in material, or the provision of shielding against fly-ash erosion.

It is interesting to compare similar provisions for corrosion or erosion found in Pressure Vessels, Section VIII of the ASME Code and in the Power Piping Code, B31.1. In UG-25 and UCS-25, Section VIII provides similar but somewhat more specific guidance on corrosion and erosion than Section I. With some exceptions for very thin vessels, allowances for corrosion or erosion are left to the designer's judgment. Section VIII also states that extra material provided for this purpose need not be of the same thickness for all parts of the vessel if different rates of attack are expected for the various parts. Finally, Section VIII states that no additional thickness need be provided when previous experience in like service has shown that corrosion does not occur or is only of a superficial nature.

The Power Piping Code, B31.1, 102.4, requires a corrosion or erosion allowance only when corrosion or erosion is expected and in accordance with the designer's judgment. Thus, the same general approach to corrosion and erosion is seen in Section I, Section VIII, and B31.1.

OPENINGS AND COMPENSATION

When an opening is made in a pressure vessel for an attachment, such as a nozzle, or for a handhole or manhole, or for any other purpose, the vessel is weakened to some extent. Accordingly, in most cases, the Code requires the designer to provide what is known as **reinforcement**, or **compensation**, for the material removed to make the opening. (The terms "reinforcement" and "compensation" are used interchangeably.) The Section I rules covering openings and compensation have evolved over the years in an incremental fashion, and they are replete with cross-references and exceptions, making them somewhat difficult to follow. Two different design approaches are used, one for so-called individual openings in shells, headers, and heads, and the other for what are called openings in a definite pattern. The latter method is often used when banks of tubes are connected to shells and headers. The basic rules covering individual openings and

compensation for them are found in PG-32 through PG-39. When groups of openings form a definite pattern, the metal remaining between adjacent holes is called a ligament. Rules for ligament design are found in PG-52 and PG-53.

The principal difference between the two design methods is in the placement of the required compensation. Under the rules for individual openings, the compensation for the metal removed must be replaced in the region immediately around the opening, which is defined by PG-36 as being within the *limits of metal available for compensation*, or the *limits of compensation*. The compensation for a single opening may be provided in the wall of the vessel, in the wall of the nozzle or other connection, or as a reinforcing pad on the vessel, or in attachment welds, or in any combination of those locations. However, when the ligament design method is used for openings in a definite pattern, all the compensation is provided in the wall of the shell, and the design is based on the average strength of the shell, expressed in terms of its so-called efficiency, *E*. **Efficiency** is a measure of the strength of a shell with a series of holes in it compared to the strength of the same shell with no holes. For example, a shell with a single longitudinal row of 2-in. (50-mm) holes on 4-in. (100-mm) centers is said to have an efficiency of 0.50, since at the row of holes, on average, only half the wall is available to carry hoop stress.

Describing the two methods as individual openings versus groups of openings is perhaps a little misleading because the design rules of PG-32 to PG-39 for individual openings also apply to multiple openings near each other, even if they are so close that their limits of compensation overlap. Also, although the ligament design method is at first defined in PG-52 as applying to “groups of openings which form a definite pattern in pressure parts,” that definition is immediately extended by PG-53 to “groups of openings which do not form a definite pattern in pressure parts.” PG-52 covers groups of tubes with either uniform spacing or a repeated pattern of spacing, such as shown in Figs. PG-52.3 and PG-52.4 (e.g., 5¼, 6¾, 5¼, 6¾, etc. in. (133, 171, 133, 171 mm)). PG-53 is intended to cover the ligament design method for groups of tubes whose spacing for some reason departs from the regular repeating pattern permitted by PG-52. PG-53 calls these tubes *unsymmetrically spaced*.

Limits of Compensation

The term limits of compensation, or limits of metal available for compensation, describes a zone around a vessel opening where extra material may be placed as compensation for the metal removed to make the opening. The size of this zone is arbitrary, but it is loosely based on experimental and theoretical studies of stresses near openings and how they attenuate with distance. Moreover, many decades of experience have shown the rules for openings and compensation to be safe and satisfactory. PG-36 and Fig. PG-33.1 explain and illustrate the concepts pretty clearly. For convenience, Fig. PG-33.1 is reproduced here.

The limits of compensation are defined by a rectangle encompassing the opening, all as illustrated in Fig. PG-33.1. It is worth noting that the definition of the terms used in Fig. PG-33.1 are listed in PG-33.3. The rules of subparagraph PG-33.1 apply to all openings other than flanged-in openings in dished heads, openings in flat heads, and openings covered in PG-32.1.2 (groups of openings designed in accordance with the rules for ligaments), PG-32.4 (openings in shells and headers for which no calculation need be made to determine the availability of compensation for a single opening), PG-32.5 (single opening in a dished head).

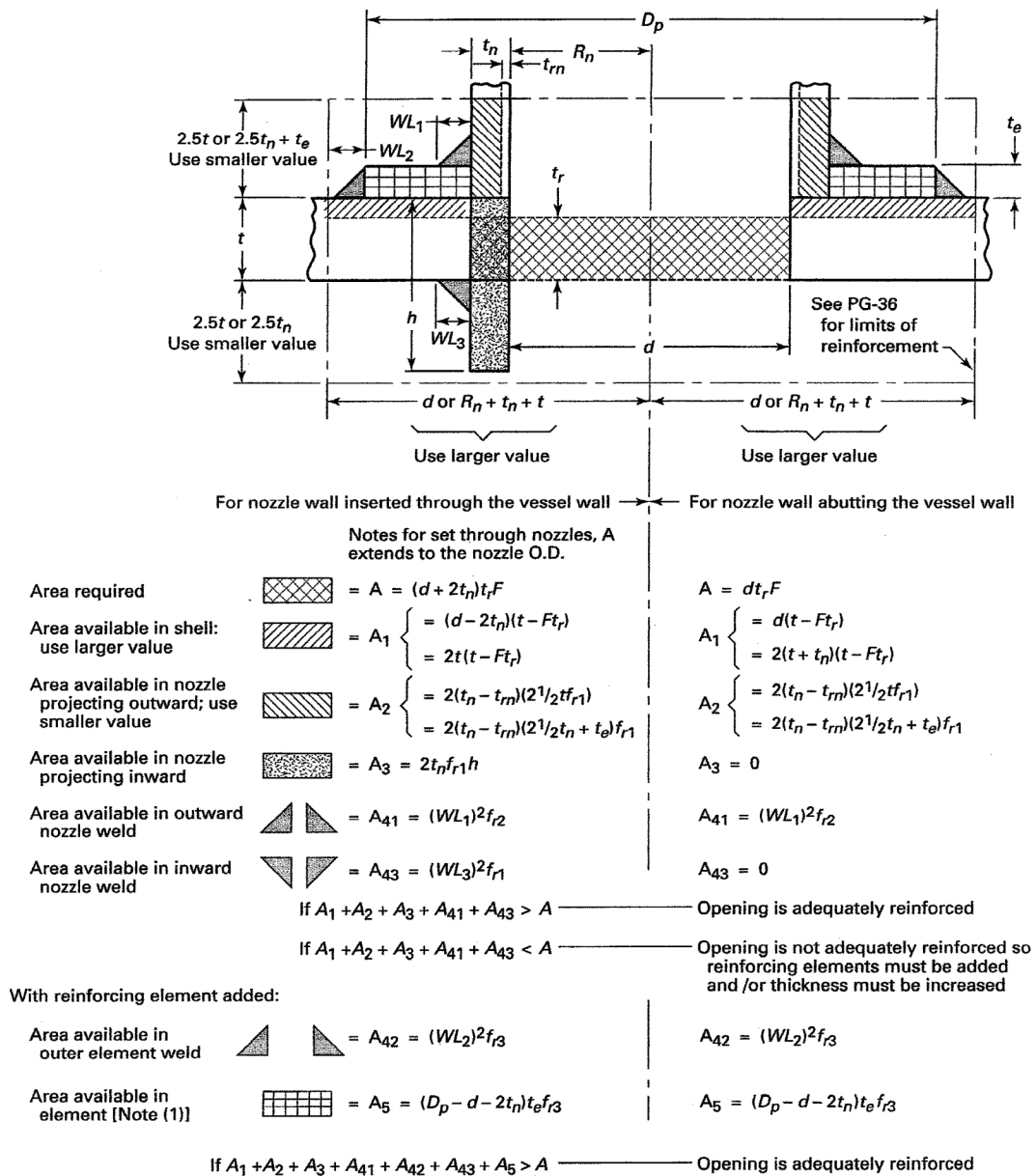
Figure PG-33.2 SOME REPRESENTATIVE CONFIGURATIONS DESCRIBING THE DIMENSIONS t_e , d and h , where:

t_e = thickness of the attached reinforcing pad

h = distance nozzle projects inward from the outer surface of the vessel wall

d = diameter in the plane under consideration

This figure should be reviewed by the designer should there be any doubt in selecting the dimensions of these terms.



GENERAL NOTES:

- (a) This figure illustrates common nozzle configurations and is not intended to prohibit other configurations permitted by the Code.
- (b) See PG-33.3 and PG-36 for definitions of nomenclature.

NOTE:

- (1) This formula is applicable for a rectangular cross-sectional element that falls within the limits of reinforcement.

FIG. PG-33.1
NOMINCLATURE AND FORMULAS FOR REINFORCED OPENINGS
(REPRODUCED FROM ASME SECTION I)

Compensation for Individual Openings

As just explained, the rules of PG-32 to PG-39 apply to individual openings or several individual openings that are not considered to fall under the rules of PG-52 or PG-53 for the design of ligaments. (Often a group of openings can be designed by either set of rules, as discussed later.)

PG-32 provides a general introduction to the rules for openings and compensation, with advice about the shape of openings and the maximum size permitted. The term **single opening**, implicitly defined in PG-32.1.3, means one spaced far enough away from any other opening so that the limits of compensation for the two openings do not overlap. Under this definition, a whole series of openings spaced at a little more than twice the diameter of the openings could be treated as a series of single openings. Alternatively, such a series could be designed using the ligament rules of PG-52, provided the diameter of the largest hole in the group does not exceed the maximum size permitted by PG-32.1.2. As a general rule, a designer is free to use whichever of the two methods suits the circumstances. (This was affirmed by Interpretation I-92-37 on reinforcement calculations for multiple openings with overlapping limits of compensation.)

The basic concept of inherent compensation or reinforcement is that if a vessel wall is thicker than is required for its design pressure, the extra wall thickness can serve as compensation for a single opening, whose size depends on a number of factors, the most important of which is the amount of extra thickness.

Compensation Required

The basic rules for determining the amount of compensation required for openings in shells and heads are given in PG-33. Although the title of this paragraph does not mention headers, this is believed to be an inadvertent omission, since headers are specifically mentioned in the title of PG-32. As noted earlier in this chapter, PG-33 starts with a list of openings it does not cover because they are covered elsewhere. That leaves individual connections that fail to meet one of the exemptions or for which other rules are provided.

As explained more fully under the heading Design Philosophy of Nozzle Attachment later in this chapter, a nozzle opening in the wall of a cylinder removes metal that would otherwise be carrying its share of the membrane stress caused by pressure in the cylinder. The highest membrane stress is in the hoop, or circumferential, direction. The area that must be replaced is based on t_r , the required thickness of a seamless shell or head calculated by the design rules of PG-27, PG-29 or Appendix A-317. Note that the area to be replaced is based only on t_r , the minimum thickness required, even if the actual thickness is greater.

Consider now a plane that passes through the center of an opening and that also contains the longitudinal axis of the vessel. In that plane the area that needs to be replaced is the diameter of the finished opening, d , times the required thickness, t_r , times a correction factor, F . Thus, the general equation for the area, A , to be replaced by compensation elsewhere is

$$A = d \times t_r \times F$$

PG-33 introduces the correction factor, F , to account for the variation in membrane pressure stress that occurs on different planes through the opening, depending on the angle between any plane and the longitudinal axis of the cylinder. The chart in Fig. PG-33.3 shows this variation. The GENERAL NOTE below the chart give the formula of $F = 1 - 0.5 \sin^2 \theta$. F is equal to 1.0 when the angle is zero and 0.5 when the angle is 90 deg. These values reflect the fact that the circumferential stress in a cylinder is approximately twice as much as the axial, or longitudinal, stress. To assure that a certain minimum portion of the reinforcing is provided in the shell, factor F is used also when a drum or shell has a series of holes in a definite pattern. This rule is found in PG-38.4.

Other Openings Exempt from Compensation Calculations

Openings for certain small connections remove so little material that the vessel is presumed to have sufficient inherent compensation and no compensation calculations are required. PG-32.1.4 gives the details: The diameter of the finished opening, d , does not exceed the larger of either

- (a) one-fourth the inside diameter of the shell or header, nor 2.375 in. (60 mm), or
- (b) the value of $d_{\max}$. Calculated in PG-32.1.2 for single opening not addressed in (a) above.

First, the diameter of the opening may not exceed $\frac{1}{4}$ of the inside diameter of the vessel (it usually would not). If that condition is met, welded connections are permitted, up to NPS 2 (DN 50). Threaded, studded, or expanded connections also qualify for the exemption if the diameter of the hole is not greater than NPS 2 (DN 50).

Shape of Openings

PG-32.2 gives advice about the shape of openings and expresses a preference for openings that are round, elliptical, or obround. Other shapes are also permitted, but in such cases, PG-32.2.2 advises that all corners should be provided with a “suitable radius.” These two paragraphs conclude their advice with the admonition to subject the vessel to a hydrostatic proof test, in accordance with the provisions of PG-100, when doubt exists about the strength or safety of a vessel with odd-shaped openings. Since these paragraphs offer no specific criteria by which to judge suitability of radii or the strength and safety of the vessel, this advice can only serve to warn the designer that he or she must proceed carefully, using past experience, engineering judgment, and if deemed necessary, a hydrostatic proof test.

Size of Openings

In PG-32, Openings and Compensation, is a sometimes overlooked subparagraph on size of openings, PG-32.3. The latter states that properly reinforced openings in cylindrical and spherical shells are not limited as to size, but must comply with the next two subparagraphs. The first of those does impose a size limit of sorts, by serving notice that Section I’s area replacement, or compensation, rules are intended to apply to openings not exceeding the following dimensions:

For vessels 60 inches (1500 mm) in diameter and less: $\frac{1}{2}$ the vessel diameter, but not over 20 inches (500 mm). For vessels over 60 inches (1500mm) in diameter: $\frac{1}{3}$ the vessel diameter, but not over 40 inches (1000mm).

Since diameter, D , is defined as outside diameter in the pipe formulas of PG-27 and the shell formulas of PG-32, the 60-in. (1500-mm) diameter mentioned in these rules is generally construed to mean outside diameter (at least in Section 1; Section VIII may have a different tradition). Thus, the largest opening permitted by the above rules may not exceed half the outside diameter for vessels up to 40 in. (1000 mm) in outside diameter; then the maximum permitted opening size stays constant at 20 in. (500 mm) until the outside diameter exceeds 60 in. (1500 mm), when the second rule applies, allowing a maximum opening size of only $\frac{1}{3}$ the outside diameter. While this sort of design rule does not seem unreasonable, by today’s standards, it would seem arbitrary and perhaps hard to justify, other than as an example of the ASME Code’s conservative, experience-based methods that have long served the industry well.

The next question is what to do if larger openings are needed? Some advice is found in PG-32.3.3, which warns the designer that larger openings should be given special attention and may be reinforced in any suitable manner that complies with the intent of the Code rules. Since that intent is far from clear, it is fortunate that some nonmandatory guidance is then offered:

- Put about two-thirds of the required reinforcing in the inner half of the limits of compensation, adjacent to the opening.
- Give special consideration to the fabrication details used and inspection employed.
- Reduce stress concentration by grinding welds to a concave contour and rounding inside corners of the opening to a generous radius.
- Finally, proof testing may be advisable for large openings approaching the full vessel diameter and openings of unusual shape.

Again, the burden is placed on the designer to base the design on experience, engineering judgment and, if necessary, hydrostatic proof testing.

At first thought, manhole openings in the drum seem to be the only major openings in a boiler, and they usually fall within the half-diameter size limit of PG-32.3.2. However, in the design of large superheater and reheater headers and piping, occasionally, a branch connection can be as large, or larger, than the header itself. Designing such a connection becomes a problem in the analysis and design of a tee. Over the years, manufacturers of these large fittings and some boiler manufacturers have developed design methods for them, including experimental testing with strain gages, proof testing, and more recently, three-dimensional finite element stress analysis, confirmed by experiment.

Occasionally, a manufacturer is caught off guard by a demand from a reviewing inspection agency for a proof test to be conducted on construction with an opening that exceeds the half-diameter size limit. Just such a situation occurred involving the connection of a 12-in. (300-mm) saturated steam line from the drum to a 14-in. (350-mm) diameter superheater inlet header. The designers had more than met the recommendations of PG-32.3.3 by using an extra thick header that effectively provided more than two-thirds of the required reinforcing close to the opening. However, the inspector who reviewed the design for the jurisdiction was concerned that this was a large opening, approaching the full-vessel diameter that might fail in service and insisted that Section I required a full-size proof test of the header with its large branch connection. Since the header had been completed and partially covered with refractory, such a proof test would have entailed either construction of a second prototype for testing or removal of the refractory from the original. Either alternative would have caused a major delay in an already tight delivery schedule and significant additional expense. Under such circumstances, a manufacturer's thorough knowledge of the Code and confidence in a design can help in obtaining prompt approval of the design from the inspection agency.

In the above-noted case, the manufacturer presented a strong case to the inspection agency, making the following points:

- PG-32.3.3 does not mandate proof tests; it merely says such a test may be advisable in extreme cases.
- More reinforcing had been provided near the opening than Section I recommended.
- A three-dimensional finite element analysis of the pipe-to-header connection showed unremarkable stresses.
- The header had passed a hydrostatic test at 1.5 times MAWP.
- The header is intended to operate at a temperature below the creep range, so the hydrostatic test suffices to demonstrate a substantial design margin.
- Several identical headers had been in service in the same jurisdiction for more than 20 years, with no problems.

After some further weeks of delay, during which a higher authority at the authorized inspection agency may have intervened, the design was approved, and construction of the boiler proceeded on schedule.

Different Rules for Size of Openings in Section VIII

Section VIII vessels come in a greater variety of sizes and shapes than do Section I vessels, since they serve so many different industries. For some applications, Section VIII vessels do indeed have large openings

or openings of unusual shape. Section VIII used to rely on the same type of nonmandatory cautionary language about large openings in UG-36 as Section I uses in PG-32.3.3. However, sometime in the mid-1980s, Section VIII changed its rules so that the recommendation to concentrate the reinforcing adjacent to the opening became mandatory. Later, based on PVRC-sponsored studies of large openings in relatively thin vessels, Section VIII added to Appendix 1-7 in the 1995 Addenda additional rules and restrictions covering large openings. For radial nozzles exceeding the one-half or one-third vessel diameter limit, formulas were provided for calculating membrane and bending stresses near the opening. Membrane stress is limited to its usual design allowable stress, S , and the combination of membrane and bending stress is limited to $1.5S$. For openings for radial nozzles whose ratio of nozzle radius to shell radius exceeds 0.7, a design in accordance with U-2(g) is required. That paragraph is the equivalent of the second paragraph of the Section I Preamble, which in effect tells the designer to prove to the Authorized Inspector that a proposed new design is just as safe as otherwise provided by the rules in the Code. (See further discussion of this Preamble paragraph in the Introduction and in Chapter 8.)

It turned out that the new Appendix 1-7 rules were too conservative and were causing a problem for some manufacturers whose vessels had openings that did not meet the new requirements. On the basis of the long satisfactory service experience with those vessels, Code Case 2236 was approved at the September 1996 meeting of the Standards Committee to grant relief from the new rules, while they were being reconsidered. The case permits large openings to be designed using alternatives to the rules in Appendix 1-7. Acceptable alternatives include successful experience with a specific design or any method that satisfies the requirements of U-2(g). Subsequently, Code Case 2236 has been annulled and its provisions have been incorporated into Appendix 1-7 of Section VIII, Division 1.

Flanged-in Openings in Formed Heads

PG-34 is a short paragraph with advice about flanged-in openings in formed heads and could be considerably clearer than it is. First, let it be said that the various head thickness formulas in PG-29 are generally fairly conservative, so that there is likely to be some extra strength in the wall to act as inherent compensation. Moreover, the calculated thickness of heads with flanged-in openings usually must be increased by 15% (see PG-29.3, 29.5, 29.7, and 29.12). Finally, the flange itself, the equivalent of a short nozzle pointing into the head, acts as a reinforcing element. Thus, the PG-33 compensation rules do not apply to flanged-in openings in heads that meet all the requirements stipulated, including the requirements of PG-29.13 for knuckle radius and knuckle wall thinning.

There are two other provisions of PG-34 worthy of mention. The first is that compensation for a manhole opening may be provided by a manhole frame or other attachment as an alternative to flanging, in accordance with the compensation requirements of PG-33. More important is that any openings (other than flanged-in openings) in torispherical, ellipsoidal, or hemispherical heads must be provided with reinforcement in accordance with PG-33.

Compensation Required for Openings in Flat Heads

PG-35 provides rules for flat heads with openings whose diameter does not exceed half the head diameter or shortest span. If the size of the opening does exceed that limit, the head must be designed in accordance with the requirements of PG-35.3, which directs the designer to use the requirements of PG-16.1. PG-16.1 states in part “that the Manufacturer, subject to the acceptance of the Inspector, shall provide details of design that will be as safe as those provided by the rules of this Section. This may be done by appropriate analytical methods, the appropriate use of rules from other design codes or, as permitted by PG-18, by proof test.”

When the size of an opening is less than half of the diameter of a flat head, the compensation required is half of that required for a cylinder. This is due to the fact that a structural member such as a flat head carries load chiefly in bending rather than as a membrane force, although it may carry some membrane force due

to the fact that the cylinder to which it is attached expands under pressure and tends to pull the head with it. Also, since the head is in bending, any connection attached to the opening acts as a stiffener. As an alternative to providing calculated compensation, presumably within the normal limits for placing compensation, the designer may modify the design formulas for the thickness of flat heads in PG-31. Different coefficients are used in those formulas, increasing the required head thickness by about 40%, effectively doubling the bending strength of the head.

Strength of Compensation

This subject is discussed under the heading Design Philosophy of Nozzle Attachment later in this chapter.

Compensation for Multiple Openings

As explained above under Limits of Compensation, when adjacent openings are close enough to each other that their limits of compensation overlap, special rules apply to ensure that no portion of the compensation is applied to more than one opening. The condition of overlapping compensation is covered by the rules of PG-38. That paragraph also establishes the minimum spacing permitted. The center-to-center distance between two adjacent openings may not be less than $1\frac{1}{3}$ times their average diameter. The designer must provide a total area of compensation equal to the sum of the areas of compensation required by PG-33 for the separate openings. Since the width of each zone of compensation is restricted by the overlap, the required compensation in the vessel wall is likely to become thicker.

Another rule comes into effect when a vessel has a series of holes whose limits of compensation overlap. In such cases, PG-38.4 requires that the net cross-sectional area within the shell wall between any two finished openings must equal at least $0.7F$ times the cross-sectional area obtained by multiplying the center-to-center distance between the openings by the required thickness t_r of a seamless shell. F is the previously mentioned correction factor from Fig. PG-33.3, which accounts for the variation in stress on different planes through the opening. PG-38.4 states that a cross-sectional area of metal equal to at least 70% of that required for a seamless vessel, over a length equal to the centerline spacing of the openings, must be provided as net cross-sectional area in the shell between the openings. Moreover, any compensation not fused to the wall of the shell may not be credited toward the 70%. This rule is a little hard to grasp without studying the examples shown in Fig. PG-38, which illustrate what is meant by compensation fused to the wall of the shell. Note that the fillet welds shown do not qualify for the 70% rule, because that rule considers only net cross-sectional area within the actual shell wall.

LIGAMENT DESIGN

The metal remaining between adjacent holes in a vessel is called a **ligament**. When groups of openings form a definite pattern, a series of ligaments is created. These ligaments may be designed using rules found in PG-52 and PG-53. As explained in the introduction to Openings and Compensation, ligaments are designed on the basis of their so-called efficiency. Efficiency is a measure of the strength of a shell with a series of holes in it compared to the strength of the same shell with no holes. If there is a longitudinal row of holes along the length of a vessel, the ligaments between those holes are called **longitudinal ligaments**, and their efficiency is called longitudinal efficiency. Similarly, if there is a circumferential row of holes spaced around the shell, the ligaments between those holes are called **circumferential ligaments**, and their efficiency is called circumferential efficiency. Similar terminology applies to a row of holes on a diagonal line, resulting in **diagonal ligaments**. The definition of longitudinal ligament efficiency is given in PG-52.2 for several examples of definite, repeating patterns of openings. In the simplest such example, a longitudinal tube row comprises a series of holes of diameter, d , at a uniform spacing (longitudinal pitch) equal to p . In that case,

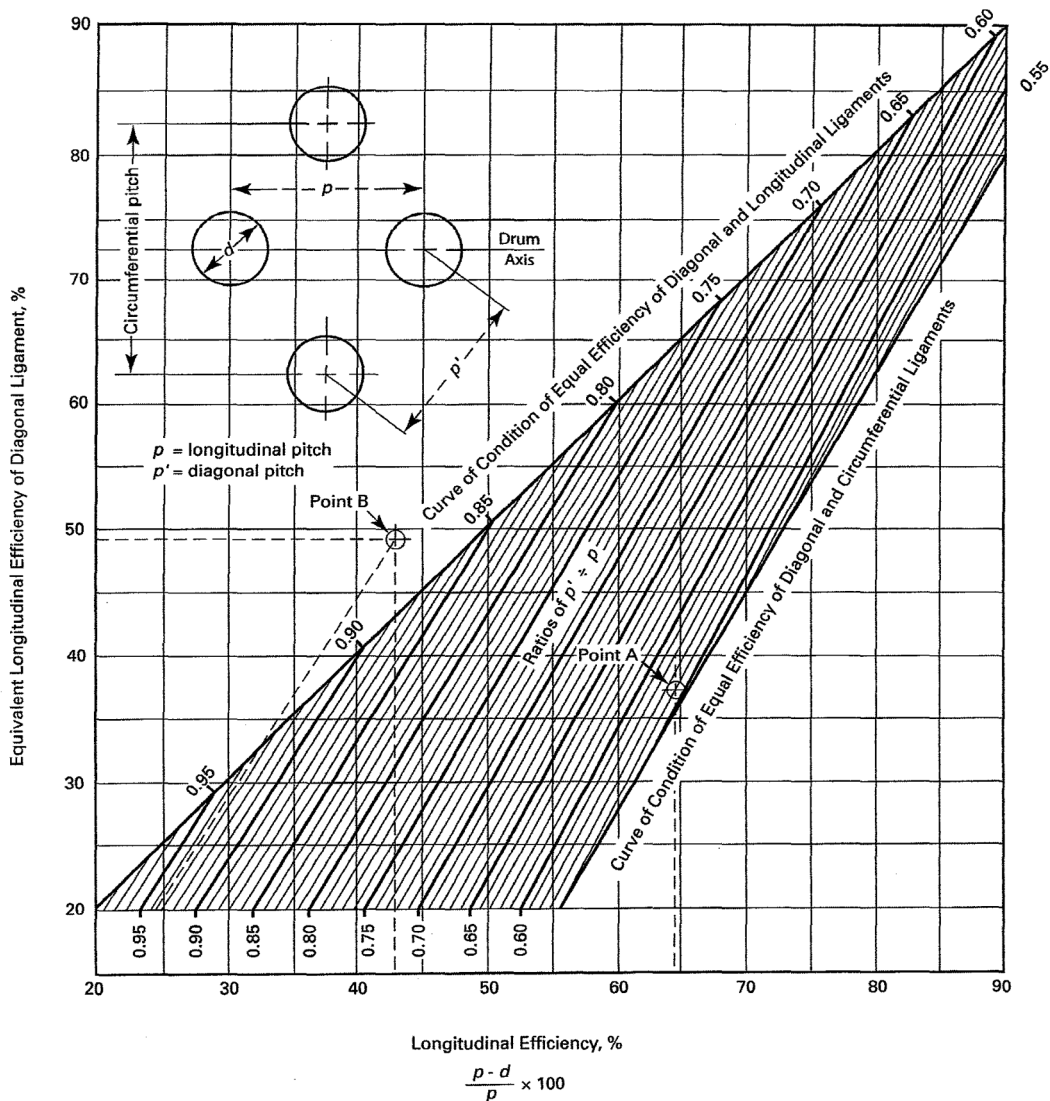
the longitudinal efficiency of the ligaments is: $E = (p - d)/p$. Pitch is measured either on the flat plate before rolling or on the median surface after rolling. One of the difficulties of designing ligaments is that potentially all three types just defined have to be checked to see which is the weakest (has the lowest efficiency) and thus controls the choice of design thickness.

One notable aspect of the efficiency approach is that it establishes an average ligament efficiency for a series of openings that may not be spaced uniformly. Note again that in this design method, all compensation for the openings is placed in the shell wall. As explained at the beginning of this chapter, if a shell has a longitudinal row of 2-in. (50-mm) diameter holes on 4-in. (100-mm) centers, its ligament efficiency, E , is found from the above formula to be 0.50. In other words, at the row of holes, on average, only half of the wall is available to carry hoop stress. Although it is nowhere mentioned in PG-52 or PG-53, the required wall thickness of a cylinder with a group of openings forming ligaments is determined from the cylinder design formula of PG-27.2.2, where the ligament efficiency, E , appears in the denominator of the formula. Because the cylinder formula is not linear with respect to efficiency (due to the extra term in the denominator), an efficiency of 0.5 does not quite cause the shell to double in thickness.

The ligament design rules become more complicated when a series of openings in a definite pattern departs from the simple example of a longitudinal row of evenly spaced holes. Figures PG-52.3 and PG-52.4 show examples of nonuniform hole spacing, but each has a repeating pattern defined by p_1 the pitch between corresponding openings in a series of so-called symmetrical groups of openings. Symmetrical groups is a misnomer; they would be better described as repeating patterns of openings. Once the pitch, or length, of the repeating pattern is established, the average ligament efficiency of the group can be determined from the pitch minus all the holes in that pitch, divided by the pitch. PG-52.2.2 gives examples of the calculation of longitudinal efficiency for the patterns shown in Figs. PG-52.3 and PG-52.4. The formula is just $E = (p_1 - nd)/p_1$, where d is the diameter of the holes, and n is the number of holes in the repeating pattern length p_1 . It may be of interest to know that the examples presently in Section I are unchanged from those in the first edition of 1914, except that the explanation of ligament efficiency was perhaps a little clearer then.

Holes along a diagonal are treated in PG-52.4 and the illustration in Fig. PG-52.5. (Note that this treatment applies only to holes arranged in a triangular or diamond pattern, such as that illustrated, and not to rectangular patterns. For the latter, which are a simpler design problem, the designer needs to worry only about the longitudinal and circumferential ligament efficiencies; the diagonal efficiency does not control.) Diagonal ligaments are designed using Fig. PG-52.1, which provides a means of determining what is called the **equivalent longitudinal efficiency of diagonal ligaments**. (Figure PG-52.1 is included in this chapter.) The figure introduces two new terms. These are p' , the pitch of the holes along the diagonal row, and p'/p , the ratio of the diagonal pitch to the longitudinal pitch. The designer enters the figure along the x -axis with the longitudinal efficiency $(p - d)/p$, finds the intersection with the line representing the ratio of p'/p , and then reads left to the y -axis to determine the equivalent longitudinal efficiency of the diagonal ligament. This equivalent efficiency may then be used as E in the PG-27.2.2 design formula for the thickness of a cylinder under internal pressure. It is apparent, then, that the expressions “designing by the ligament method” and “the design of ligaments” describe a process of calculating the appropriate ligament efficiency to use in the PG-27.2.2 formula for the design of piping, drums, and headers.

From a brief study of Fig. PG-52.1, we can envision a number of situations that are not so straightforward as the example just explained because the equivalent longitudinal efficiency of the diagonal ligaments may not control the design. This situation is further complicated by the fact, as previously mentioned, that the pressure stress in a cylinder varies, depending on the direction being considered. Thus, Fig. PG-52.1 is divided into three zones. If a point falls within the central triangular zone, the diagonal ligaments are the weakest and control the design. The cylinder is designed as just described, using the equivalent longitudinal efficiency in the design formula of PG-27.2.2. The boundaries of this central zone are borders that signify that the efficiency of the diagonal ligaments is no longer the efficiency on which the design should be based. When a point falls within the triangular upper left-hand zone of the figure, the longitudinal ligaments are weaker than the diagonal ligaments, and as explained in PG-52.4, the design in such cases is to be based on the longitudinal ligament efficiency $(p - d)/p$. Two examples illustrating the use of Fig. PG-52.1 for the design of diagonal



GENERAL NOTES:

(a) Equations are provided for the user's option in Notes (b), (c), and (d) below. The use of these equations is permitted for values beyond those provided by Fig. PG-52.1.

(b) Diagonal efficiency, % = $\frac{J + 0.25 - (1 - 0.01 E_{long}) \sqrt{0.75 + J}}{0.00375 + 0.005 J}$, where $J = (p'/p_1)^2$.

(c) Curve of condition of equal efficiency of diagonal and circumferential ligaments,

$$\text{diagonal efficiency, \%} = \frac{200M + 100 - 2(100 - E_{long}) \sqrt{1 + M}}{(1 + M)}, \text{ where } M = [(100 - E_{long}) / (200 - 0.5 E_{long})]^2.$$

(d) Longitudinal efficiency, % = $E_{long} = [(p_1 - d) / p_1] 100$.

FIG. PG-52.1
DIAGRAM FOR DETERMINING THE EFFICIENCY OF LONGITUDINAL AND DIAGONAL
LIGAMENTS BETWEEN OPENINGS IN CYLINDRICAL SHELLS
(REPRODUCED FROM ASME SECTION I)

ligaments are given in PG-52.4. If a point representing a diagonal ligament should fall within the lower right-hand zone of the figure, the circumferential ligaments are weakest, and the design thickness would be based on their ligament efficiency. Remember though that circumferential ligaments require only half the strength and efficiency of longitudinal ligaments, as explained further in the following paragraph. The pitch of the circumferential ligaments is shown in Fig. PG-52.1.

Circumferential ligaments are given brief mention in PG-52.3, Openings Transverse to the Vessel Axis. These are ligaments that are subject to a longitudinal stress, which in a cylinder with no openings is essentially half the hoop, or circumferential, stress. Thus, all things being equal, circumferential ligaments may be made half as strong (i.e., may have half the efficiency) as longitudinal ligaments. As a practical matter, cylinders are usually designed using the PG-27.2 formula, which is based on hoop stress. The required thickness is determined using the appropriate ligament efficiency (longitudinal or equivalent longitudinal). However, Fig. PG-52.1 does not give a longitudinal efficiency that is the equivalent of circumferential efficiency. Thus, if a point falls in the lower right-hand zone of that figure, it is necessary to do a separate calculation for circumferential ligament efficiency, to verify that it governs the design of the cylinder and to ensure that the circumferential ligaments have at least half the strength (or efficiency) of the longitudinal ligaments. Stated another way, the designer can establish the equivalent longitudinal efficiency of a circumferential ligament by doubling its nominal efficiency. That nominal efficiency is determined as in the first example of PG-52.2, except that circumferential pitch instead of longitudinal pitch is used in the formula. Thus, the designer may potentially have to deal with three different ligament efficiencies for use in the design formula of PG-27.2: longitudinal efficiency, a longitudinal efficiency that is the equivalent of the diagonal efficiency, and a longitudinal efficiency that is the equivalent of the circumferential efficiency (i.e., is twice the circumferential efficiency). The lowest value controls. However, it would be unusual for circumferential ligament efficiency to govern the design thickness of a cylinder.

PG-52.5 contains some confusing advice about symmetrical groups of tubes arranged in lines parallel to the axis. This advice becomes clearer when turned around and read to say: When tubes or holes are arranged in a drum or shell in symmetrical groups along lines parallel to the axis and the same spacing is used for each group, *the efficiency on which the maximum allowable working pressure is based shall be not less than the efficiency of any of those groups.*

The next complication in the design of ligaments occurs when for some reason the groups of openings do not form a regular repeating pattern. This situation is covered in PG-53 in the description of openings that do not form a definite pattern. These ligaments are designed by using average ligament efficiencies calculated over certain lengths. The vessel design is based primarily on the lowest average longitudinal ligament efficiency over a length equal to the inside diameter of the drum. That lowest efficiency is found by studying the hole pattern and deliberately choosing the position of the diametral length that encompasses the most openings. A secondary design condition is then imposed to prevent a significantly smaller local ligament efficiency within the one diameter length. For a length equal to the inside radius of the vessel and for the position that gives the lowest efficiency, the efficiency may not be less than 80% of that on which the design of the vessel is based.

The last ligament situation (covered by PG-53.3) is that in which rows of holes are placed longitudinally along a drum, but the holes do not line up in the circumferential direction. All of the previously described PG-53 rules would apply, except that diagonal ligaments would be formed between holes in adjacent rows that are offset from each other. The equivalent longitudinal efficiency of these diagonal ligaments is found by using Fig. PG-52.6. (Fig. PG-52.1 and Fig. 52.6 are different representations of the same underlying equations.) From the arrangement of the two diagonal holes shown in the latter figure, the designer can easily determine θ , the angle between the diagonal and the longitudinal axis, and the ratio of the diagonal pitch to the diameter of the hole, p'/d . With those values, the equivalent longitudinal efficiency of the diagonal ligament can be determined. An equation in Fig. PG-52.6 is provided as an alternative means of determining that efficiency. The longitudinal efficiency is multiplied by the longitudinal pitch of the two holes having the diagonal ligament to get an equivalent (reduced) longitudinal pitch to use in the PG-53 procedures for determining the average ligament efficiency over a length of one inside diameter or one inside radius. Partly

because of all these tedious complications, manufacturers generally do not use the irregular patterns that would involve the rules of PG-53. Section IV has evolved a simpler method of ligament design, using the factor F of Fig. PG-33.3 to account for the variation in pressure stress on diagonal ligaments. Section I may eventually adopt a similar approach.

The rules for ligament design in Section VIII came from Section I originally, and they are almost identical. However, the explanation accompanying the Section VIII rules is a little different and a little more comprehensive. A review of those rules is recommended to gain a better understanding of the rules in Section I.

INTERPRETATIONS ON OPENINGS, COMPENSATION, AND LIGAMENTS

Because this subject can be quite daunting, a number of past interpretations may prove helpful. One of these, I-95-06, deals with the question of using individual compensation versus designing by the rules for ligaments and also illustrates what is meant by a single opening:

Question: If openings have reinforcement limits which do not overlap, and each opening has sufficient reinforcement within those limits to satisfy the individual requirements, may each opening be considered a single opening for which ligament efficiency calculations are unnecessary?

Reply: Yes.

Among the PG-36 definitions of metal available for compensation is the nominal thickness of the nozzle wall, t_n . Many nozzles are made of pipe, a product form that is usually specified by its nominal wall thickness. However, the governing pipe material specifications permit a manufacturing tolerance on wall thickness of -12.5% , and even though the definition calls for nominal thickness, BPV I has by interpretation insisted that the minimum thickness be used in compensation calculations. That Interpretation is I-86-09, Definition of Nominal Wall Thickness:

Question: Does the term t_n , as defined in PG-36.4.4, pertain to the nominal wall thickness defined for the schedule rating of the pipe used for the nozzle?

Reply: No. The term t_n pertains to the actual thickness of the nozzle wall. See PG-27.4, Note 7.

Unfortunately, this interpretation puts Section I at odds with Section VIII, which defines t_n as nothing more or less than the nominal wall thickness. Section VIII's reasoning to support this view is that the manufacturing tolerance merely permits an eccentricity between the inner and outer surfaces of the pipe. Consequently, if one side of the pipe is thin, the other side will make up for it; the nominal thickness is actually present and available when the whole circumference of the pipe is considered. The Power Piping Code, B31.1, uses yet another definition for what it calls T_b , the thickness of a branch. This is defined as the actual thickness of the wall (by measurement) or the minimum wall thickness permissible under the purchase specification. While there is probably some justification for the use of each of these definitions, presently, an effort is under way to reach agreement on a common definition of nominal thickness for all three codes, in keeping with a general ASME policy that the various Code sections should have consistent rules and definitions, unless there is good reason not to. In 1997, the Subgroup on Design decided to recommend to BPV I that Section I interpret nominal thickness in the same way that Section VIII does, namely, that nominal means nominal. BPV I accepted this recommendation, and it is expected that Interpretation I-86-09 will be revised and reissued. Until an agreement on a consistent interpretation of the term "nominal thickness" is reached, it is important that the designer use the definition in the particular code governing the construction involved. Otherwise, difficulties might ensue should an Authorized Inspector discover that the wrong definition had been used.

In 1992, an inquiry was received asking about a nozzle-to-header connection, not specifically addressed in Section I, in which the inside diameter of the nozzle is larger than the opening in the header. The pertinent question from Interpretation I-92-29 is:

Question: When a nozzle is attached to a header and the inside nozzle diameter is larger than the opening in the header, may the diameter of the opening in the header be taken as d in the ligament efficiency calculation of PG-52?

Reply: Yes; also please direct your attention to Interpretation I-89-48.

Interpretation I-89-48, described below, permits the use of as-machined dimensions of the opening in the header to be used for calculating an equivalent opening of uniform diameter.

There have been relatively few inquiries about the rules for ligaments, perhaps because they have been in the Code since there first was a Code, and therefore, there is general agreement on how to use them. A few of the inquiries worth mentioning include I-89-47, I-89-48, and I-89-49 and deal with holes that for one reason or another do not have a constant diameter. One of the questions was, essentially, whether the **equivalent average diameter of the hole** could be used in calculating the ligament efficiency. In the case of nozzle-to-header connections, the committee ruled that an average diameter equivalent to the as-machined opening in the header could be used. However, in the case of tube or nozzle connections, such as those shown in Fig. PW-16.1, sketches (y) and (z), the committee ruled that the use of equivalent opening diameter is not permitted, even were credit to be taken only for that portion of the tube or wall actually welded to the shell. Yet, in the determination of whether the limits of compensation overlap, Interpretation I-89-49 does permit the use of an equivalent hole diameter if the variation in diameter is based on the fact that only some portions of the nozzle wall are welded to the vessel wall, as described in PG-38.4 and illustrated in Fig. PG-38. Thus, some of these interpretations appear to be inconsistent, and the designer should be forewarned.

In Interpretation I-92-34, an inquirer asked the following question about placing a fully reinforced connection within a ligament.

Question: For Section I construction, where the shell thickness has been determined by means of a ligament efficiency in accordance with PG-52, is it permissible to locate a fully reinforced connection within the ligament?

Reply: Yes; however, t , used in the reinforcement calculation must be calculated using the ligament efficiency used to determine the shell thickness.

NOZZLE ATTACHMENT RULES

Design Philosophy of Nozzle Attachment

Rules for the welded attachment of nozzles and other connections to vessels or headers are found in PW-15, PW-16, and PG-37. These rules are intertwined with several related topics: openings, compensation, and load-carrying paths, as further explained below. The rules are directed primarily at the welding of a cylindrical nozzle to a cylindrical vessel (although they also apply to nozzles on vessel heads of various shapes).

Recall from the earlier discussion of membrane stresses that the walls of cylinders, such as boiler drums, are designed to carry hoop (circumferential) stresses caused by the primary loading of concern, namely, internal design pressure. A nozzle opening in the wall of a cylinder removes metal that would otherwise be carrying its share of this hoop membrane stress. Under Section I design rules (PG-32 through PG-39), the metal removed for the opening usually must be replaced by reinforcement, or compensation, in a region around the opening. That region, described by the term “limits of metal available for compensation” is defined in PG-36. In theory, when compensation is placed around the opening in this manner, the hoop membrane forces are carried around the opening without significantly raising the average local stress. (In the 1930s, this theory was validated by photoelastic stress studies. More recently, three-dimensional finite element analyses have provided further confirmation.)

Several options are available for the placement of the compensation, many of which are illustrated in Fig. PW-16.1. Compensation may be provided by extra wall thickness in the vessel or the nozzle, or by a reinforc-

ing pad around the nozzle, or by deposited weld metal. Any combination of these methods may be used, so long as the compensation is placed within the prescribed limits.

Consider now the case in which the compensation is provided not by extra thickness in the vessel wall, but by extra thickness in the nozzle wall and/or a reinforcing pad on the cylinder. According to the compensation theory, the membrane forces that were formerly carried by the metal removed from the shell must now be carried by compensation that is not integral with the shell. These membrane forces must be transferred from the shell to the compensation, pass around the opening, and then return to the shell. This transfer of load must be accomplished by the weld metal attaching the compensation. Thus, the basis of the nozzle attachment rules, and what is intended by the second sentence of PW-15.1, is the following: *Sufficient weld and compensation shall be provided, on either side of the of the plane through the center of the opening, parallel to the longitudinal axis of the vessel, to develop the required strength, as prescribed in PG-37, in shear or tension in the weld, whichever is applicable.*

Current Section I Rules

In the mid-1970s, BPV I sought some relatively simple equations to help the designer apply the nozzle attachment rules, which until that time had been expressed in words only, as described above. What was needed were equations that would permit the designer to determine the loading to be carried by the nonintegral compensation and a convenient way to verify that there was sufficient weld to transfer that loading to the compensation. The assistance of the (then) Subcommittee on Design was enlisted, and that committee developed rules for adoption by several book sections. In Section I, those rules were placed in PG-37 and PW-15 and illustrated in Fig. PW-15, which is included in this chapter for ready reference. The rules require a two-step approach. The first step is to determine the load, W , to be carried, using the expression for W found in PG-37.2, as follows:

$$W = (A - A_1) S_v$$

Where W is the required weld strength to attach elements that are not an integral part of the vessel wall,

A is the reinforcement area required (see Fig. 33.1),

A_1 is the area available in shell (see Fig. 33.1),

S_v is the allowable stress in vessel (see PG-33.1).

When the rules for nozzle attachment were first developed in the mid-1970s, there were three equations for determining the load, W . This has now been simplified by the single equation shown above.

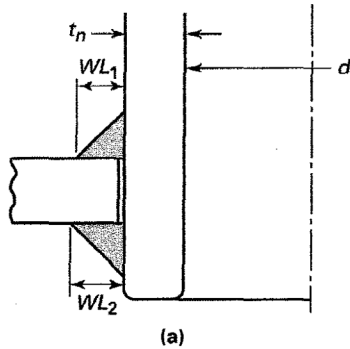
The load, W , to be carried by the welds attaching the nonintegral nozzle attachments is simply the area of the required material removed from the shell less the reinforcement area provided by the excess shell thickness multiplied by the allowable stress of the shell material.

The second step is then to verify that the welds attaching the nozzle are able to carry the load, W . This is done by following the rules provided in PW-15 and the sample calculations shown in Fig. PW-15. PW-15.1 states in part "Nozzles, other connections, and their compensation may be attached to vessels by arc or gas welding. Sufficient weld and compensation shall be provided on either side of the plane through the center of the opening, parallel to the longitudinal axis of the vessel, to develop the required strength, in shear or tension, which ever is applicable." See Fig. PW-15 below for sample calculations, where, if a fillet weld has unequal legs, the value of WL_1 or WL_2 shall be taken as the length of the shorter leg.

Subparagraphs of PW-15 provide the following details for evaluating the strength of the attachment welds. The stress concentration factors in PW-15.2 apply to all welds (PW15.1.1). The strength of fillet welds shall be based on one-half the area subject to shear, computed on the average diameter of the weld (PW-15.1.2). The strength of groove welds shall be based on one-half the area subjected to shear or tension, as applicable, computed using the minimum weld depth dimension in the direction under consideration (PW-15.1.3).

Certain nozzle attachment welds do not require strength calculations; see PW-15.1.6 for details. When the minimum requirements for attachment welds are met, per PW-16, strength calculations for nozzle attachment welds are not required for weld configurations shown in Fig. PW-16.1, illustrations (a) through (c), (g), (h), (o), (q-1) through (q-4), (u-1), (v-1), (w-1), (y), and (z).

To recap, the general approach in designing nozzle attachment welds is first to determine the load to be carried and then to check each of the applicable load-carrying paths to see if the combined strength of the load-carrying elements on that path is adequate to carry that load.



(a)

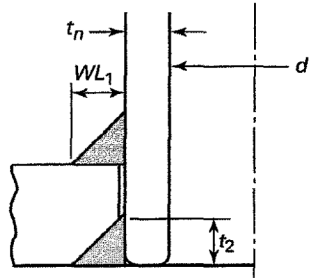
For sketch (a):

Required weld strength (PG-37.2):

$$W = (A - A_1) S_V$$

Weld strength = WL_1 in shear + WL_2 in shear

$$= 0.49 \left(\frac{1}{2} \right) WL_1 \pi (d + 2t_n + WL_1) S_V f_{r1} + 0.49 \left(\frac{1}{2} \right) WL_2 \pi (d + 2t_n + WL_2) S_V f_{r1}$$



(b)

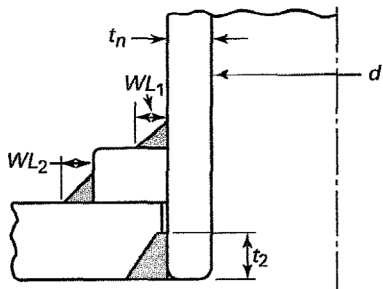
For sketch (b):

Required weld strength (PG-37.2):

$$W = (A - A_1) S_V$$

Weld strength = WL_1 in shear + t_2 in tension

$$= 0.49 \left(\frac{1}{2} \right) WL_1 \pi (d + 2t_n + WL_1) S_V f_{r1} + 0.74 \left(\frac{1}{2} \right) t_2 \pi (d + 2t_n) S_V f_{r1}$$



(c)

For sketch (c):

(1) Required weld strength (PG-37.2):

$$W = (A - A_1) S_V$$

Weld strength = WL_2 in shear + t_2 in tension

$$= 0.49 \left(\frac{1}{2} \right) WL_2 \pi (D_p + WL_2) S_V f_{r3} + 0.74 \left(\frac{1}{2} \right) t_2 \pi (d + 2t_n) S_V f_{r1}$$

(2) Check nozzle to pad and shell (PG-37.3):

$$W = (A - A_1 - A_{42} - A_5) S_V$$

Weld strength = WL_1 in shear + t_2 in tension

$$= 0.49 \left(\frac{1}{2} \right) WL_1 \pi (d + 2t_n + WL_1) S_V f_{r1} + 0.74 \left(\frac{1}{2} \right) t_2 \pi (d + 2t_n) S_V f_{r1}$$

FIG. PW-15
EXAMPLES OF WELD STRENGTH CALCULATIONS
(REPRODUCED FROM ASME SECTION I)

Discussion of Current Design Rules Determining the Load to Be Carried

The formula for W in PG-37.2 represents the load carried by that portion of the compensation that is not integral with the vessel wall multiplied by the allowable stress. PG-37.3 states, in part, that when a reinforcing pad is required by the rules of PG-33, the welds attaching the nozzle to the pad and the shell shall be checked independently to assure that the loads carried by the individual elements can be transmitted by the attaching welds. The formula for W now becomes:

$$W = (A - A_1 - A_{42} - A_s)S_v$$

Where W is the required weld strength to attach the reinforcing pad to the shell and to the nozzle,

A is reinforcement area required (see Fig. 33.1),

A_1 is the area available in shell (see Fig. 33.1),

A_{42} is the area available in outer element weld (see Fig. 33.1),

A_s is the area available in element (see Fig. 33.1),

S_v is the allowable stress in vessel (see PG-33.1).

The designer should also note that, in certain cases, the welds attaching elements of compensation need not satisfy the weld strength calculation requirements of PG-37.2 (see PG-37.4).

Determining the Strength of Attachment

Having determined load, W , the designer's next problem is to determine how and where it is to be carried. Remember that W is supposed to be the load that the nonintegral compensation must carry, and sufficient weld must be provided to transfer that load to whatever compensation will carry it. That compensation may consist of any of the various elements described above.

As explained in PW-15 (and examples shown in Fig. PW-15), the strength attributed to the various types of attachment welds must be calculated (when applicable) to ensue that they meet the required strength as proscribed in PG-37.

The designer is told to base the strength of each of these elements on only half the area in shear or tension. Using half the area is just a convenient device to avoid dividing the areas along the load-carrying path by two to account for the fact that the load must be transferred from the vessel wall to the compensation on both sides of the plane through the center of the opening. An example shown in the appendix makes this clear. Figure A-67 of example A-67 shows a studed flange welded to a vessel opening by means of internal and external fillet welds. The required minimum strength to be provided by the welds has been calculated (in accordance with PG-37) and compared with the calculated strength of the internal and external fillet welds, in shear, using the provisions of PW-15. The strength of these welds is based on half the total area of contact between the leg of the fillet weld and the surface of the vessel or attachment as applicable. That total area is determined by taking the product of the mean circumference of the weld leg times its radial dimension, i.e., the size of the leg.

The allowable stresses for these various elements are given in PW-15.2 as a percentage of the allowable stress of the vessel material. The percentages vary from 49% for fillet weld legs (not throats) in shear, to 74% for groove welds in tension. A note explains that these rather conservative values have been reduced to account for joint efficiency and the effect of combined end and side loading. Unlike Section VIII, Section I does not provide explicit rules to account for the possibility that some portion of the compensation may have a lower allowable stress than the vessel material it is supposed to be replacing. However, the designer is told in PG-37.1 that material of lower strength may be used for compensation only if its area is increased in proportion to the relative strength of the two materials. Note though that no extra credit may be taken for compensation that happens to be stronger than the vessel wall.

Acceptable Nozzle Configurations

It is difficult to generalize about nozzle attachment welds, since there are so many configurations possible. Many are shown in Fig. PW-16.1 (included in this chapter), which is deliberately entitled *Some Acceptable Types of Welded Nozzles and Other Connections to Shells, Drums, and Headers*. This title clearly implies that other connection details could be used. The use of the phrase “some acceptable types” is a Code tradition, and it applies to several illustrations in Sections I and VIII, such as those depicting flat heads and covers (Fig. PG-31), lug weld details (Fig. PW-16.2), and tube attachment details (Fig. PFT-12.1). This tradition is based on the statement in the Foreword to all sections of the Code that the rules are not to be interpreted as limiting in any way the manufacturer’s freedom to choose any method of design or any form of construction that conforms to the Code rules. While this statement does imply some flexibility in the rules, as a practical matter, a manufacturer might find it difficult to devise details or configurations different from those already illustrated. Even if the manufacturer was able to develop some new form of construction, its acceptance would have to be obtained from the Authorized Inspector, as noted in the second paragraph of the Preamble.

The extensive variety of nozzle attachment configurations shown in Fig. PW-16.1 includes quite a few where the nozzles are attached by full penetration welds. Examples include sketches (a), (b), (c), (g), (h), (o), (q-1) through (q-4), (u-1), (v-1), and (w-1). If we accept the principle that a weld is as strong as the base metal, it is clear that some of these welds do not represent any kind of potential weak point in the vessel. As explained above, the configurations shown in the sketches mentioned above are obviously so strong that they do not need any strength calculations for nozzle attachment welds, and PW-15.1.6 exempts them from such consideration. It should be noted that the welds shown in sketches (y) and (z) in Fig. PW-16.1 are also exempt from the requirement to make load carrying calculations per PW-15.1.6.

Inquiries Regarding Nozzle Attachment Strength

Minimum Attachment Welds. Several unusual aspects of the application of these nozzle attachment rules have been a continuing source of confusion and inquiries to Subcommittee 1 (currently BPV-1). The first of these is the fact that the required weld strength, W , sometimes turns out to be negative, in which case it is to be taken as zero. This can happen when there is enough compensation within the vessel wall that none is needed external to it, and thus, no weld is needed to transfer load from the vessel to the compensation. Therefore, no check of load-carrying paths should be required (see next paragraph).

In that case, how much weld is really needed to attach the nozzle? The answer is found in PW-16, which gives minimum requirements for attachment welds and illustrates them in Fig. PW-16.1. Thus, if the PG-37.2 rules show that W is small or zero, the minimum requirements of PW-16 apply by default. In the opinion of the authors, these minimum attachment welds are adequate, as has been demonstrated by many decades of safe service using both Sections I and VIII construction.

DISHED HEADS

Heads are used as end-closure members for drums and headers. They may vary in shape from flat to hemispherical. Section I uses the term **dished heads** to describe several types of rounded heads for which design formulas are provided in PG-29. These include:

- Heads whose shape is described as **torispherical**, consisting of a segment of a sphere surmounted by a portion of a torus called the knuckle. These heads are designed using the formula of PG-29.1 for a head described as a **blank unstayed dished head**, which is a segment of a

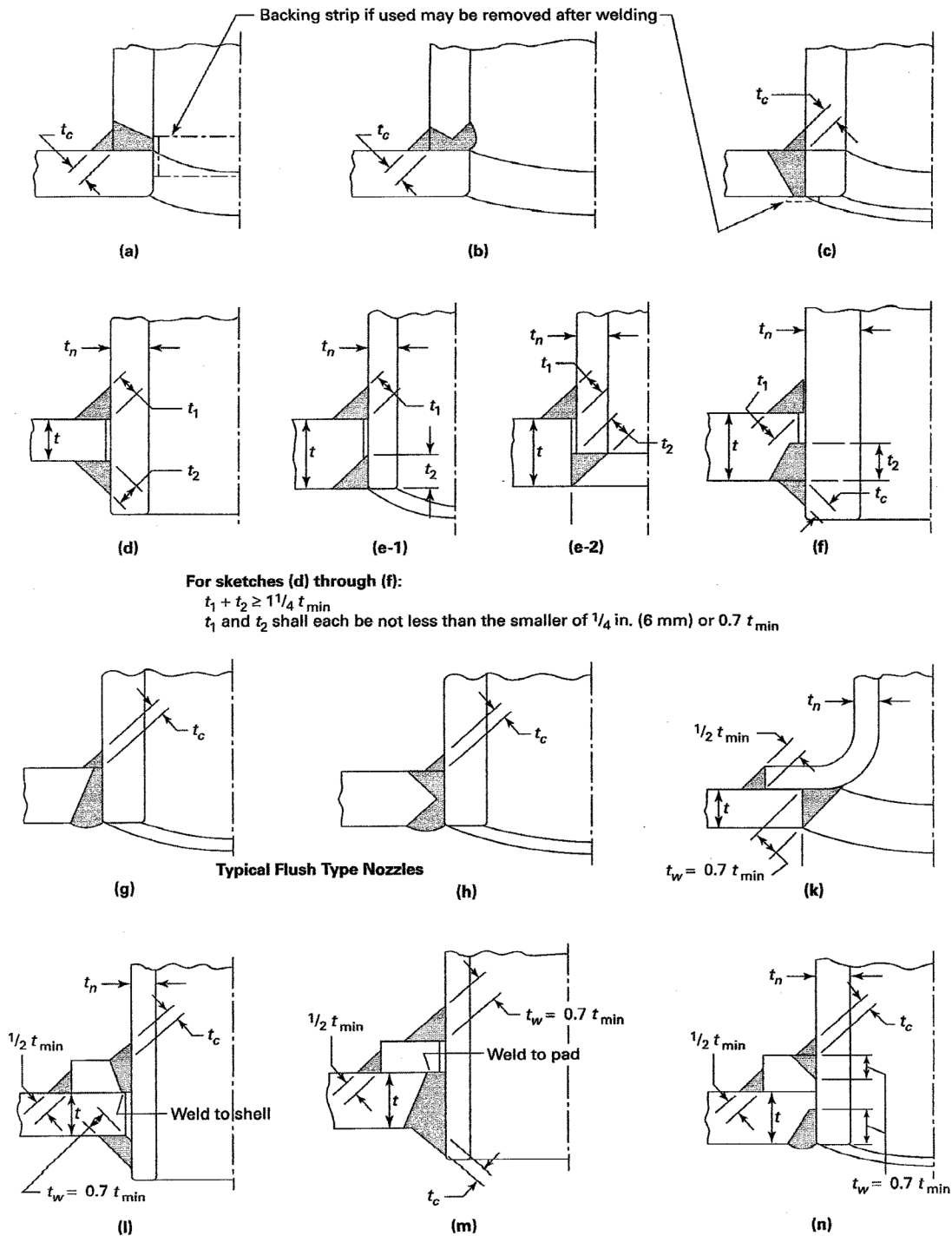
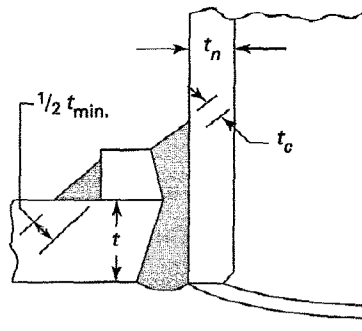
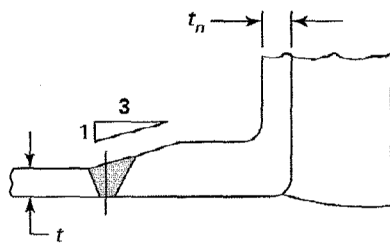


FIG. PW-16.1

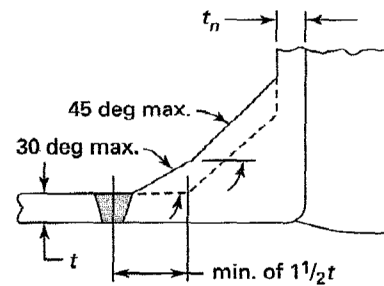
SOME ACCEPTABLE TYPES OF WELDED NOZZLES AND OTHER CONNECTIONS TO SHELLS, DRUMS, AND HEADERS (REPRODUCED FROM ASME SECTION I)



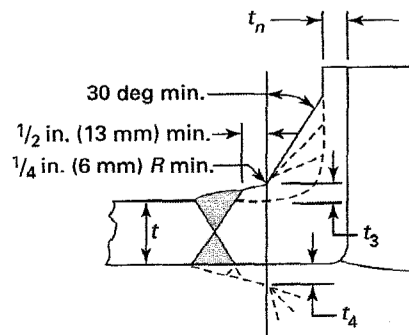
(o)



(q-1)

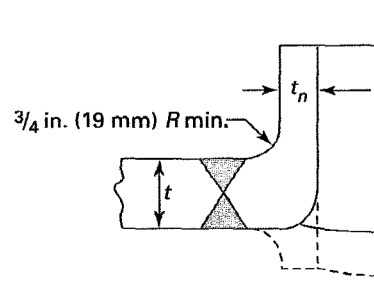


(q-2)



$t_1 + t_4 \leq 0.2 t$ but not greater than $1/4$ in. (6 mm)

(q-3)



(q-4)

FIG. PW-16.1
SOME ACCEPTABLE TYPES OF WELDED NOZZLES AND OTHER CONNECTIONS TO SHELLS, DRUMS, AND HEADERS (CONT'D)

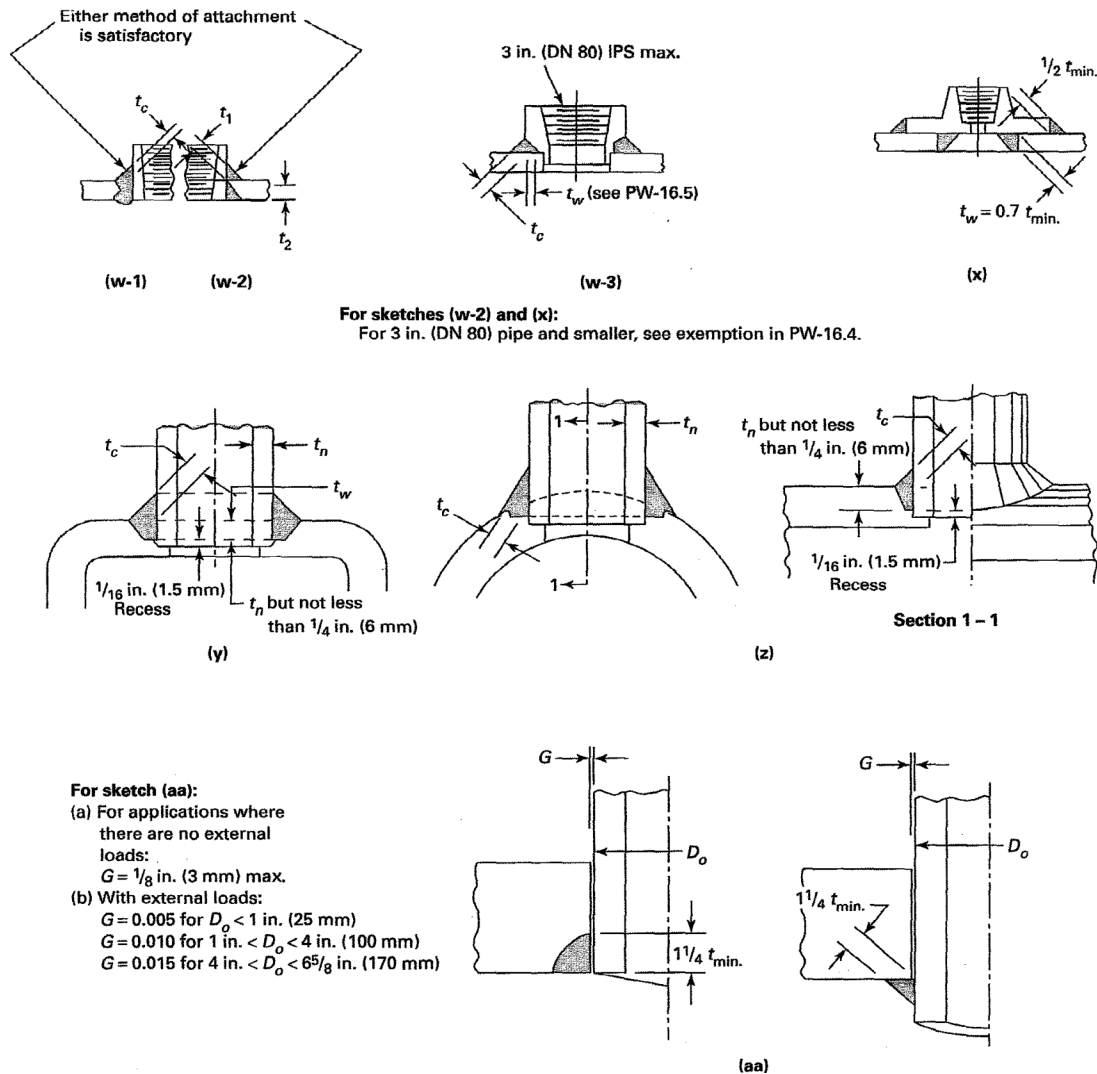


FIG. PW-16.1
SOME ACCEPTABLE TYPES OF WELDED NOZZLES AND OTHER CONNECTIONS TO SHELLS, DRUMS, AND HEADERS

sphere, with pressure on the concave side. The corner radius of the dish, also known as the knuckle radius, and the amount of wall thinning permitted during forming of the knuckle are governed by the rules of PG-29.13.

- Heads whose shape is described as **semiellipsoidal**, typically the shape of a two-to-one ellipse, i.e., a head in which half the minor axis (the depth of the head) is one-quarter the diameter of the shell. Design rules for such heads are given in PG-29.7. They must be fabricated to the shape tolerances of PG-29.8, so that their shape closely approximates that of a true ellipse. The thickness of a blank ellipsoidal head (one with no openings) is required to be at least equal to that of a seamless shell of the same diameter, as provided in PG-27.2.2.
- Heads that are full **hemispheres**. These are designed in accordance with PG-29.11 and may be made thinner than any other type of head.

- Heads may be made thinner than called for in the design formulas of PG-29 only if they are stayed in accordance with the rules of PG-30.
- Section I also permits the use of flat heads and covers, in accordance with the rules of PG-31.

It happens that the most efficient shape for containing pressure is the sphere. When a sphere is subject to internal pressure, it develops only membrane stresses, which are essentially uniform across the thickness, so that all of the material in the wall is able to carry the full allowable stress. As the shape of a head departs from a spherical shape, the stresses are no longer just membrane stresses; bending stresses develop also. The greater the departure from a spherical shape, the more bending stresses develop. In a flat head, the stresses are almost all bending stresses. Carrying pressure loads by developing bending stresses is less efficient than carrying them by membrane stresses because bending stresses vary through the head thickness, changing from tensile stress on one surface to compressive stress on the other. The stress can reach the allowable stress only at the surfaces of the material; the rest of the material is not used at its full potential. This behavior is reflected in the head design formulas. The formula for a full hemispherical head requires the thinnest wall; the other formulas call for much heavier walls.

One of the first constraints on the shape permitted for a dished head is found in PG-29.2, which describes a head formed by two radii, one for the crown and one for the knuckle. The crown radius, L , is limited to the outside diameter of the flanged portion of the head. (PW-13 requires a short flange on all but hemispherical heads, to facilitate the welding of the head to the cylinder. A full hemisphere does not need such an extra flange because where it meets the cylinder, it is already essentially cylindrical in shape.) This limit on L ensures that the head will not be so shallow that excessively high bending stresses would develop, since with a large radius, a head begins to resemble a flat head.

Various types of heads with flanged-in manholes are described in PG-29.3, PG-29.7, and PG-29.12. In each case, the head is required to have extra thickness to compensate for the flanged-in opening; as specified in PG-29.3 and PG-34. Because they are thus provided with what experience has shown to be sufficient compensation for the opening, PG-29.4 exempts these flanged-in openings from having to comply with the PG-33 compensation rules. All other openings in any type of head must be compensated in the usual manner, following the rules of PG-33, unless they are exempt from compensation calculations by the rules of PG-32 for heads having inherent compensation. PG-29.3 also specifies the minimum permitted distance between two manholes placed in the same head (one-quarter of the outside diameter of the head).

The design rules of PG-29 are intended primarily for internal pressure on heads that are concave to the pressure, so that the stresses are tensile, and there is no need to be concerned about buckling or instability. Usually, heads are concave to the pressure, but once in a while, this may not be the case. PG-29.9 gives some limited advice about such situations: it arbitrarily limits the maximum allowable working pressure to 60% of that for heads of the same dimensions with pressure on the concave side. However, this rule may not be applied to either the semiellipsoidal heads of PG-29.7 or the full hemispherical heads of PG-29.11. Presumably, this is because those heads are relatively thin and would be more likely to buckle under compressive stress. Thus, the 60% rule can be applied only to torispherical heads. If a designer wanted to use a hemispherical or ellipsoidal head with pressure on the convex side, he or she would have to do a special buckling analysis to meet the intent of the second paragraph of the Preamble or perhaps do a proof test, as described in PG-18.

Full hemispherical heads are designed by the provisions of PG-29.11. This paragraph has two formulas. The second of the two requires thinner walls for any realistic design conditions, and as a practical matter under the provisions of PG-29.11, it may be used for all heads thicker than $\frac{1}{8}$ in. (3 mm). This paragraph also has formulas for use at high pressures when the usual formulas (based on so-called thin shell theory) are no longer accurate. This threshold occurs when the required thickness of the head exceeds 35.6% of the inside radius, an unlikely occurrence in the boiler industry.

Also included in PG-29.11 is some last advice about joints in full hemispherical heads. They must meet all requirements for longitudinal joints in cylindrical shells, except that when a head is butt welded to a shell, the middle lines of the plate thicknesses need not be in alignment.

FLAT HEADS

Dished heads are usually more economical than flat heads as end closures on drums, but flat heads and covers are often used on smaller vessels and headers, particularly at lower pressures, when a slightly thicker flat plate costs less than a forged head. Rules for the design of unstayed flat heads, cover plates, and blind flanges are given in PG-31. The rules cover both circular and noncircular heads and covers. Some of the many types of flat heads available are illustrated in Fig. PG-31. (For convenience, Fig. PG-31 is included in this chapter.) As usual, when Section I provides illustrations, it notes that other forms of construction that meet the rules are also acceptable. The heads shown in Fig. PG-31 are welded, threaded, bolted, and crimped. The head thickness design formulas vary somewhat, depending on the method of attachment to the shell and the shape of the head. Design advice and limitations are given with the thickness formulas for the various types of heads shown.

The design formulas of PG-31 are all based on the bending stress caused by pressure acting on a flat plate. This is an exception to the general rule that Section I design is based on hoop membrane stress in a cylinder. Since flat head design is based on maximum bending stress, the allowable stress for welded flat heads has effectively been increased to $1.5S$, as noted in the definition of the factor C that appears in the design formulas (S is the normal allowable membrane stress). The bolts of some bolted covers, such as those shown in sketches (j) and (k) of Fig. PG-31, introduce a bending moment in addition to that caused by pressure. This extra bending moment is accounted for by the second term under the square-root sign in formulas (2) and (5).

Radiography of most of the types of welds used to attach the various heads shown does not produce meaningful results because the configurations do not present a uniform thickness to the passage of X-rays. Consequently, it is difficult to detect and interpret the kind of discontinuity that might indicate a defective weld. Accordingly, footnote 14 exempts welds shown in sketches (e), (f), (g-1), (g-2), (i), (r), and (s) from radiography.

INTERPRETATIONS ON HEADS

There are a few Interpretations that clarify the application of PG-29 rules on the design of heads. Interpretation I-86-19 addressed the thickness of the flue or flange in flanged-in openings:

Question: When using ellipsoidal dished heads with flanged-in (flued) manways meeting the requirements of PG-29.3 and PG-29.7, does the minimum thickness apply to both the gage (main portion) and the flanged-in (flued) section?

Reply: Yes.

Question: May the rules of Section VIII Division 1, UG-32, for flued-in openings in ellipsoidal heads be used in lieu of the rules in Section I?

Reply: No.

This is another case in which Section I and VIII rules have drifted apart, and in such cases, the Section I rules apply.

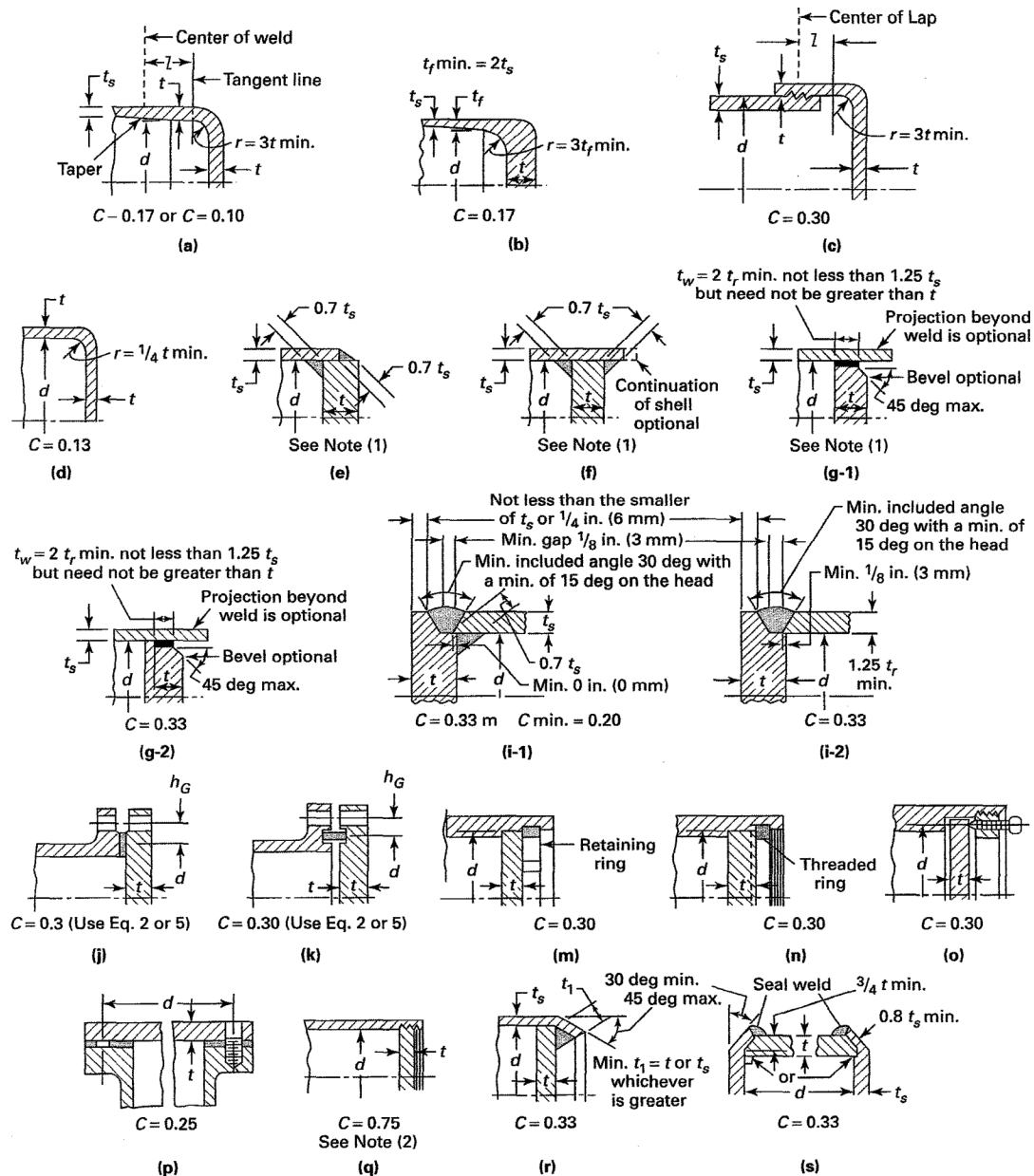
Although there seems to be no good reason why a flued-in opening could not be designed under the rules of PG-33 like any other opening if the designer so chose, Interpretation I-81-26 is stated otherwise:

Question: May a flued-in (flanged-in) opening be designed per the rules for welded nozzle attachment in PG-33?

Reply: No. The rules of PG-33 apply to welded construction as illustrated in Fig. PW-16.1 and are not intended for use with flued-in (flanged-in) constructions.

A related Interpretation, I-80-31, issued not long before I-81-26, discussed the question of flanged-in versus compensated openings:

Question: Are there valid reasons for penalizing flanged-in openings in hemispherical heads as compared to built-up and welded internal projecting necks, or compared to cut openings through weld overlaid reinforcing metal?



GENERAL NOTE: The above illustrations are diagrammatic only. Other designs that meet the requirements of PG-31 will be acceptable.

NOTES:

(1) For illustrations (e), (f), and (g-1) circular covers, $C = 0.33m$, $C \text{ min.} = 0.20$; noncircular covers, $C = 0.33$.

(2) When pipe threads are used, see Table PG-39.

FIG. PG-31
SOME ACCEPTABLE TYPES OF UNSTAYED FLAT HEADS AND COVERS
(REPRODUCED FROM ASME SECTION I)

Reply: The added thickness required by the Code for flued-in (flanged-in) openings helps compensate for the material removed in the forming operation. Other designs are permitted but require full replacement of the metal removed.

This last statement provides a reasonable basis to question the validity of the statement in I-81-26, that the rules of PG-33 may not be applied to flanged-in openings. In other words, if a flued-in opening happened to provide full replacement of the metal removed, there is no theoretical need to require an extra 15% wall thickness. However, the extra 15% rule was imposed as a good rule of thumb on the reasonable assumption that a flued-in opening would not provide full replacement of the metal removed for the opening.

Interpretation I-86-41 dealt with the design of a hemispherical head that was not quite a full 180-deg. hemisphere, for reasons of economy and ease of fabrication:

Question: May the head design formula of PG-29.1 be used for a head which is less than a full hemisphere provided the finished configuration of the vessel encompasses a full hemispherical head and all other rules of Section I are met?

Reply: Yes.

Interpretation I-86-64 explained that PG-29.7 should be used for the design of semiellipsoidal heads, not the formula of PG-29.1, which applies to heads whose central portion forms a segment of a sphere.

Interpretation I-92-88 asked whether the PG-29.7 rules for a semiellipsoidal head with a flanged-in manhole apply to a welded manhole or access opening in a semiellipsoidal head:

Question: May compensation for welded manholes or access openings in an ellipsoidal head be provided only by increasing the head thickness by 15% in accordance with PG-29.3, and with no consideration of the rules of PG-32 through PG-39?

Reply: No.

There were two reasons for this reply. The flanged-in portion of the manway would not be available as compensation, and it was not clear that the extra head thickness imposed by using the radius specified by PG-29.7, in the formula of PG-29.1, would have been provided.

There have been a few Interpretations on flat heads. One of these, I-86-27, dealt with the proof testing of bolted head flanges:

Question: For Section I construction, is proof testing permitted for the design of flanges other than those covered by ANSI standards listed in PG-42?

Reply: Yes, or as an alternative, the rules of Section VIII, Division 1, Appendix 2, as permitted by the Preamble, may be used.

Ordinarily, if Section I has rules for the design of some component, proof testing is not permitted, in keeping with a policy described in the Appendix paragraph on proof testing, A-22. However, in this case, the rules are elsewhere, so proof testing is permitted.

The fact that other types of heads than those shown in Fig. PG-31 may be used was affirmed in Interpretation I-86-86:

Question: Is it permissible to use an alternative to the types of flat heads shown in Fig. PG-31?

Reply: Yes, provided the type of flat head is not expressly prohibited by Section I and the concurrence of the Authorized Inspector is obtained.

STAYED SURFACES

The cylindrical, dished, or flat pressure-retaining elements comprising a boiler are usually designed to be self-supporting. However, certain flat and curved surfaces may sometimes be designed more economically

if they are designed as stayed surfaces, which receive some or all of their support from an array of tension members called stays, staybolts, or stay tubes.

Stays may be **through-stays**, which carry loads from one stayed surface to another, parallel surface. **Diagonal stays** are sometimes used when through-stays would be much longer or would interfere with access into the boiler through a manway. Diagonal stays between a tubesheet of a firetube boiler and the boiler shell transfer some of the pressure load on the tubesheet to the shell, where it is balanced by axial membrane loads in the shell coming from the other end of the shell. In a firetube boiler, the tubes also act as stays between the tubesheets at either end of the cylindrical shell. These tubesheets can, therefore, be much thinner than if they were designed by the formulas for flat heads in PG-31. Stay tubes, stays, staybolts, and diagonal stays are illustrated in Figs. A-8, PW-19.4(a), PFT-25, PFT-27, and PFT-32.

Stayed Flat Plates

Section I rules for stayed construction are found in PG-46 through PG-49, PW-19, PWT-12, and PWT-13 and many paragraphs of Part PFT, which covers construction of firetube boilers. The design of flat stayed surfaces rests on a few simple principles. The stays are usually laid out with uniform spacing called the pitch, p , in rows that may be described as horizontal and vertical or radial and circumferential. If the pitch between vertical and horizontal rows is not equal, the larger value is used in determining the required thickness of the stayed surface. The design may be approached in either of two ways. The designer can choose the spacing of the staying members and then determine the plate thickness required to span the distance between stays and the size of stays required to carry the load brought to them by the plate they support. Alternatively, the thickness of the plate may be chosen first and the stay pattern then laid out so that the maximum allowable pitch for that thickness of plate is not exceeded.

Consider first the problem of determining the required thickness of a flat stayed surface, using the formula of PG-46 that establishes thickness as a function of pressure and pitch of the stays. This formula is seen to be nothing more than a bending stress formula of the same type as that used to design flat heads in PG-31, except that the coefficient, C , reflecting the particular type of construction happens to be in the denominator instead of the numerator, and its values have been adjusted accordingly. A bending stress formula, in its essence, is simply a statement that the bending stress is the bending moment divided by the section modulus of the bending element. The bending moment is usually expressed as the product of some appropriate coefficient, k , the unit load (the pressure, P), and the square of the span of the element (the pitch, p , squared), or kPp^2 . The section modulus assumed for the plate is that traditionally assumed for a 1-in. (25-mm) wide section of thickness, t , namely, $t^3/6$. Using this formulation, we can show that the bending stress is $S = 6kPp^2/t^3$. Rearranging to solve for t , we find that $t = p\sqrt{6kP/S}$. This result is seen to be the same as formula (1) in PG-46, if we let $6k = 1/C$. Thus, $k = 1/6C$.

The values of C given for different types of stays vary from 2.1 for threaded or welded stays in plates whose thickness is not over 7/16 in. (11 mm) to 3.2 for a threaded stay that effectively strengthens the plate it supports with large, thick washers on the outside and nuts both inside and out. We can find the value of the coefficient, k , for the first type of stay just described to be $k = 1/6C = 1/6(2.1) = 0.079$. This value approximates the coefficient appropriate for the bending moment in a uniformly loaded square plate of dimension, p , and thickness, t , supported at its corners by stays, and by symmetry, having no rotation at the edges. Thus, the stayed surface is, in effect, being designed as a series of small squares with edges fixed against rotation (but not deflection), supported by stays at each corner. (Timoshenko discusses this problem in his book *Theory of Plates and Shells*, under the heading Bending of Plates Supported by Rows of Equidistant Columns.) The coefficient, k , for the stronger construction (with large, thick washers) is found to be $1/6(3.2) = 0.052$ and would result in a slightly thinner plate if the pitch was kept constant or a slightly greater permissible pitch if the plate thickness was held constant. However, it happens that threaded stays and large, thick washers are not at all common these days, when it is so much easier (and thus cheaper) to use welded stays.

Stayed Curved Surfaces

Most stayed construction today involves the staying of flat (as opposed to curved) surfaces. Rules for the design of stayed curved surfaces are provided in PFT-23. They involve calculating the maximum allowable working pressure for such surfaces as the sum of the pressure that could be carried by the curved surface alone and the pressure that can be carried by the stays. For most of today's designs, the use of stayed curved surfaces is no longer economical. Many details of stayed construction, such as the locomotive boiler shown in Fig. PFT-23.1, hark back to the early 1900s and are now little used.

Direct Stays

The second problem of stayed construction is the proper design of the stays themselves. Although Section I is somewhat imprecise in its use of the terms "stays" and "staybolts," the design method is the same for either. The load carried by a **direct stay** (one perpendicular to the surface it supports) is the product of the pressure times the area supported by the stay. Here again, the basic approach is very simple. By PFT-26, the area supported by a stay is a rectangle whose dimensions are the pitch of the stays in each direction. In other words, each stay supports its tributary area, half way to the next stay in each direction. PFT-26 stipulates that the area occupied by the stay is to be deducted from the area it is assumed to carry, since by considerations of force equilibrium, the area occupied by the stay cannot contribute to the net tensile load it carries. The actual cross-section of a direct stay or a staybolt is determined by following the rules of PFT-28 and PG-49. The load on the stay is divided by the allowable stress for the material of the stay, found in Table 1A of Section II, Part D, and the result is multiplied by 1.10. The extra 10% provides a degree of conservatism and may compensate for any inaccuracy in the assumption that the load on a given stay is a function only of its so-called tributary area.

Diagonal Stays

PFT-32 advises that for **diagonal stays**, the required area of a so-called direct stay is to be scaled up by a length ratio, the ratio of the diagonal length, L , shown in Fig. PFT-32 to its straight projected length, l . This increase reflects the higher load in a stay not perpendicular to the plate it supports. Applying the length ratio is seen to be the equivalent of dividing the area of a direct stay by the cosine of the angle that the stay makes with the shell. As an alternative design method for diagonal stays, PFT-32.2 allows the use of 90% of the regular allowable stress. This alternative is permitted only when the length ratio mentioned above does not exceed 1.15, i.e., when the angle between the diagonal stay and the shell does not exceed about 30 deg. For shallower angles, the reduced allowable stress design method may be used. For steeper angles, the stay area required is that of a direct stay scaled up by the length ratio of PFT-32.1.

Stay Tubes

The design of stay tubes supporting tubesheets in firetube boilers is quite different from the design of watertubes used in other types of boilers. The stay tubes are under external pressure and must be designed for stability under compressive hoop stresses, using the special rules of PFT-50 and PFT-51. In addition, of course, these stay tubes are axially loaded, in tension. The designer must verify that the tube is adequate to withstand both of these loadings.

Code Changes

Design of Stay Tubes. In 1995, BPV I approved changes to the PFT-31 rules for stay tubes used to support the tubesheets in a firetube boiler. The revised rules were issued with the A96 Addenda. The old PFT-31

formula had treated the tubes in the aggregate, requiring them to have a total metal cross-sectional area equal to the following: the pressure load on the net area of the tubesheet containing the tubes (after deducting the aggregate area of the holes) divided by S , the maximum allowable stress value for the tubes. S was not allowed to exceed 7000 psi (47 MPa). The pitch of the stay tubes was based on the formula in PG-46 using values of C specified in PFT-31.2, which depended on tube arrangement and whether or not the tube ends were shielded from the action of flame or radiant heat from the firebox. The old method had a number of shortcomings: it did not consider the loading on individual stay tubes; only the average tube load was considered. The allowable stress for the tubes was a constant value of 7000 psi (47 MPa) regardless of the tube material or temperature. Also, the practice of measuring the pitch of stay tubes between centers was resulting in considerable overdesign of the tubesheet because it ignored the fact that large-diameter tubes occupy a considerable portion of the area being stayed, effectively reducing the actual span of the tubesheet between tubes. Another problem was that there was no clear definition by which the designer could distinguish between a so-called stay tube and a regular tube. (There actually is none; any tube rolled into the two tube sheets of a firetube boiler cannot help but act as a stay tube.)

In the 1996 Addenda, PFT-31 was revised to define when a tube needs to be checked as a stay for its ability to support an axial load as well as external pressure. When tubes are used as stays supporting tubesheets, their required cross-section is to be determined by the PG-49 method of taking 1.1 times the load carried, divided by the allowable stress of the material. However, the new rules state that if tubes fall within or on the perimeter of a group of tubes that are spaced at less than twice their average diameter, they are not considered to be stay tubes, and no calculations need be made to check their cross-sectional area. That is because experience shows that tubes spaced so closely can easily carry the pressure load on the area tributary to them, and the span between the outside diameter of the tubes is small enough that no check of bending stress in the tubesheet is needed. Whatever thickness is chosen for the stayed portion of the tubesheet in a location where the tubes or stays are not closely spaced will suffice where the tubes are closely spaced. The last change was to include in PFT-31.2 a modified version of the tubesheet design formulas of PG-46 that establish tubesheet thickness as a function of pressure and tube or stay pitch. A new term under the square-root sign in these formulas ($\pi d^2/4$) recognizes some beneficial effect of the reduced span between the outside diameter of the tubes compared to the center-to-center pitch. Finally, only two values of the coefficient C are permitted, 2.1 and 2.2, depending on whether the tubesheet is over 7/16 in. (11 mm) thick. The old penalty of 20% on the C value when the ends of the tubes are not shielded from the action of flame or radiant heat was eliminated; it was not considered to be justified.

Design Temperature. In the firetube boiler, the hottest components are the firetubes, the furnace, and possibly the tubesheets, since they have hot gases on one side and water on the other. Until changed by the 1997 Addenda, the PFT-50 rules for the choice of design temperature to be used for the design of firetube boiler components subject to external pressure were not entirely clear. For the furnace and firetubes, both of which are under external pressure, PFT-50 used to call for a design temperature which was “the greater of that specified in PG-27.4, Note 2, or PFT-17.7 (when applicable).” The former rule is for tubes under internal pressure, and the latter rule (now deleted) applied to ring-reinforced furnaces under external pressure. Thus, it was not clear which rule was applicable to tubes under external pressure. The PFT-50 rule is that the design temperature shall be not less than the maximum expected mean wall temperature established by calculation or measurement. As an alternative to calculating or measuring the maximum expected mean metal temperature, 700°F (370°C) may be used as the design temperature (see cautionary note 3 to PFT-50.1). This footnote warns that a higher temperature may be appropriate for furnaces thicker than 1 in. (25 mm) or subject to high heat input. For tubes absorbing heat, it is probably conservative to use a minimum design temperature of 700°F (370°C). However, such a choice would probably have little economic impact, since these tubes are usually selected to be thicker than the design formula requires, just to provide adequate strength for handling and expanding. For furnaces, a design temperature of 100°F (55°C) above the water temperature is adequate unless the furnace is over 1 in. (25 mm) thick or has a high heat input, in which case the designer should calculate the maximum expected mean wall temperature. The choice of

design temperature for other parts of a firetube boiler, those subject to internal pressure, such as the shell and tubesheets, is left to the designer.

Areas of Heads to Be Stayed. Rules for calculating the areas of segments of heads or tubesheets to be stayed have been included in one form or another in every edition of Section I since the first. Strangely enough, however, no instructions are provided as to how this area is to be used, other than to record it on the Manufacturer's Data Report Form. The area might conceivably be used to determine the total number of stays required by dividing the area supported by a single stay into the total area required to be stayed. However, such advice is not provided by Section I and, if it were, would usually result in an excess number of stays because of special rules that increase the allowable pitch of stays adjacent to the shell. In 1993, the Subgroup on Design of BPV I decided to review the rules for calculating the area of segments of heads to be stayed, for both firetube and watertube boilers, with the object of deleting them. Letters were sent out by the secretary of BPV I to about a dozen manufacturers of firetube boilers asking them if they saw any purpose or need in continuing to require the calculation of the areas to be stayed. The responses received confirmed that no one was using the calculated area in designing the stays or the tubesheets. The only apparent use of the area to be stayed was to list it on the P-2 Manufacturer's Data Report Form. Accordingly, in late 1996, the Subgroup on Design voted to delete the rules requiring the calculation of areas to be stayed. These deletions included PWT-13, the first part of PFT-24, Figs. PFT-24.1 and PFT-24.2, notes on Appendix Fig. A-8, sketches (q) and (r), and Appendix Table A-4, Net Areas of Flanged Heads. Revisions were also made to PFT-27.9, the P-2 Manufacturer's Data Report, its instruction guide (A-351), and the Section I index, to remove references to the area to be stayed. At the same time, the Subgroup on Design recommended clarifications of the PFT-50 rules for choosing the design temperature of furnaces and tubes under external pressure. These changes were approved by BPVI and the Standards Committee in 1997 and appeared in the 1997 Addenda to Section I.

SUPPORTS AND ATTACHMENT LUGS

This subject is dealt with rather briefly in PG-55. That paragraph gives advice on several aspects of lug design and fabrication. The first requirement is that the lugs or hangers must be properly fitted to the surfaces to which they will be attached. The lugs may be attached by welding that meets the requirements of Part PW, including postweld heat treatment. No radiography is required because the welds are of the type for which radiography does not yield meaningful results. Three types of welds are permitted, full and partial penetration welds, as well as fillet welds along the entire periphery of the lug. Acceptable forms are shown in Fig. PW-16.2. Loads on lugs and hangers are to be determined by the designer, taking into account the weight of the component and its contents. Advice is provided on how to calculate the allowable load on fillet welds and full penetration welds. Guidance on the strength of these welds may be found in PW-15.2. Finally, materials for lugs are not restricted to the Section I pressure part materials listed in Section II, Part D; any structural material of weldable quality will do. A material of weldable quality is one whose carbon content is less than 0.35% and which has been proven weldable by the weld procedure qualification requirements of Part PW.

LOADING ON STRUCTURAL ATTACHMENTS

In many boilers, the tubes are supported in some fashion or other by lugs welded to them. The loading from the lugs causes bending stresses in the tube walls that add to the stresses already present due to internal pressure. Some means are needed to limit the combined stress due to pressure and mechanical loading to a safe value. To help designers arrive at a safe limit, for decades, Section I provided Fig. PW-43.1, Chart for Determination of Allowable Loading on Structural Attachments to Tubes.

The chart had a series of curves for a limited number of tube sizes for use when the tube lug was pulling on the tube and a single curve for use when the lug was compressing the tube. Along the x -axis of the chart was a variable, the outside diameter of the tube divided by the square of the wall thickness. The maximum allowable loading in pounds per inch of lug length was given along the y -axis. The designer entered the chart with the appropriate value of OD/t^2 , moved vertically to the tube size being checked, and then horizontally to the y -axis to determine the allowable load per inch of lug. (The lug is welded along the tube in the axial direction, as shown in Fig. PW-43.2.) Several examples were provided in Appendix A-71 through A-74, illustrating how to determine the allowable lug load for several loading conditions: tension, bending, combined compression plus bending, and loading on a tube bend.

One drawback of the chart in Fig. PW-43.1 was the limited number of tube sizes that it covered; another was the fact that no allowance was made for tube materials of different allowable stresses. A manufacturer submitted an inquiry asking whether the chart could be expanded to include more tube sizes and perhaps include the effect of different allowable tube stresses. Since the origin of the existing chart could not be ascertained, the task of developing an expanded version of it was turned over to the Subcommittee on Design. A major function of that subcommittee is to assist other subcommittees in the development of special analysis or design methods.

The development of the new chart and new design method took a long time, with the results finally appearing in the 1992 Addenda. The new method handles any size tube, any allowable tube stress, and accounts for a new factor, the so-called lug attachment angle (the angle subtended by the tube lug, as shown in Table PW-43.1). Also, any extra tube wall thickness above that needed for pressure alone is now accounted for; it increases the allowable loading on the tube lug. There are only two curves on the new chart, one for compression loading on the tube, the other for tension loading. The designer can read load factor values from the plotted curves or, alternatively, can calculate load factors from equations provided. The equations also extend the range of the plotted curves. The load factor equations are merely curve fits of the underlying ring equations. The x -axis of the new chart in Fig. PW-43.2 is essentially unchanged from the pre-1992 chart, but the variable measured on the y -axis of the chart is now called a load factor, L_r . The maximum allowable unit load of attachment, L_a , is derived from L_r , as explained further below.

Very briefly, the new design approach is based on combining the tube stress due to internal pressure with the local circumferential bending stress caused by the lug load. The tube is modeled as a ring with a concentrated zone of loading acting radially on an arc whose length is equal to the thickness of the lug. The allowable combined stress was based on the design-by-analysis methods of Section VIII, Division 2, considering the combination to be in the category of primary plus secondary stress, but with a lower stress limit than that permitted by Section VIII. The reason there are different curves for tension and compression is that the ring is treated as a curved beam. It happens that when a curved beam is subjected to a bending moment, the bending stresses on the opposite surfaces are not equal and opposite, as they are in a straight beam. They are higher on the inside radius.

A compression load from the lug causes a tensile bending stress on the inside surface of the tube, which adds to the pressure stress, which is also a tensile stress. A tensile load from the lug again causes a higher stress on the inside than the outside, but it is a compressive stress and is not additive to the pressure stress. The governing combination in this case occurs on the outside surface, where the slightly lower bending stress adds to the pressure stress. The fact that the bending stress is slightly lower on the outside explains why the chart shows slightly higher allowable load factors (and thus higher allowable lug loads) for tension loading. Notice that the two curves converge as the D/t^2 ratio approaches 500 because as that ratio increases, the curvature of the tube grows smaller and smaller (i.e., locally it becomes straighter and straighter) so that the curved beam effect that results in higher stresses on the inside surface disappears.

When PW-43 was revised in 1992, the sample problems in Appendix A-71 to A-74 illustrating the determination of allowable loading on tube lugs were revised to show the new method. Somehow, the explanation of the examples as printed was not as clear as the subcommittee had intended, and the examples are a little hard to follow. Accordingly, to serve as a guide to the method, the first of the sample problems, shown in A-71, is reworked and explained as Design Exercise No. 4 in Appendix IV.

DESIGN OF PRESSURE RELIEF VALVE NOZZLES

Section I (and Sections IV and VIII also) are silent on the subject of designing pressure relief valve nozzles to resist the forces that develop when a pressure relief valve discharges. Historically, this is probably due to the fact that the manufacturers of safety valves and the designers of the relatively short nozzles on which they are mounted are well aware of the potentially high reaction forces and moments the pressure relief valves can generate and have designed the valves and nozzles to accommodate those loads.

As previously explained, under Section I's design philosophy, most pressure-containing components are designed on the basis of a design stress that is a membrane stress. Bending stresses are not explicitly covered, even though they are implicit in some of the design formulas for flat heads and stayed surfaces, such as those found in PG-31 and PG-46. Pressure relief valves are usually equipped with a discharge elbow, permitting the discharge to go vertically into an exhaust stack. The reaction force from the discharge causes a large bending moment on the nozzle supporting the pressure relief valve. The designer of the pressure relief valve nozzle thus must deal with a combination of normal pressure loading plus the bending moment and possibly an axial thrust downward on the nozzle. Since Section I provides no design rules for this situation, the designer must rely on engineering judgment in determining how best to proceed.

There are several aspects to this design problem. One is the determination of the reaction force on the valve while it is discharging. The pressure relief valve manufacturers know what these forces are, from theory and experiment, and often provide this information in their literature. Alternatively, B31.1, Power Piping Code, has a Nonmandatory Appendix II, Rules for Design of Safety Valve Installations, which is a comprehensive guide containing advice on determination of discharge loads for both open and closed systems. Open systems discharge to atmosphere, often through exhaust stacks (called vent pipes in this appendix). An elbow on the discharge of the pressure relief valve directs the flow into the stack, which is independently mounted on cold steel. The pressure relief valve itself moves with the piping on which it is mounted as that pipe undergoes thermal expansion. In closed systems, not often used for steam, the discharge is piped to some kind of receiving vessel.

Appendix II also cautions that all parts of the piping system (including the exhaust stacks) must be designed not only for the effects of the pressure relief valve discharge forces, but also for thermal expansion, dead weight, earthquake, and other mechanical loads (such as vibration of the effects of more than one valve opening at the same time). Other topics covered include dynamic amplification of reaction forces due to the sudden nature of their application, the various load combinations to be considered, and the allowable stress criteria for each load combination.

Note that the design of pressure relief valve installations on a boiler differs depending on their location. If the pressure relief valves are mounted on the drum or directly on a superheater or reheater header, their nozzles are considered part of the boiler proper, subject only to Section I design rules. On the other hand, if they are mounted on main steam or reheat piping, the nozzles are considered to be boiler external piping, subject to the design rules of B31.1. This turns out to make a significant difference, as will now be explained.

Around 1980 designers of safety valves began to complain that designing pressure relief valve nozzles using the design stresses of Section I (which are membrane allowable stresses) was resulting in very massive nozzles, seemingly all out of proportion to the valves mounted on top of them. Code Case 1876 was developed to overcome the two major causes of the problem: The first was that at elevated temperature, the governing criterion that set the allowable stress at a relatively low value was "two thirds of the average stress to cause creep rupture in 100,000, hours." Since the pressure relief valves can never blow for that length of time, this was considered an inappropriate criterion. The Code Case, therefore, was based on the design philosophy pioneered in Section III's elevated temperature design rules, which permit some allowable stresses to be based on the length of time they are expected to be applied. Using this philosophy, the 1000-hr time-dependent rupture stress was chosen for the case, thereby giving the designer an allowable stress higher than ordinarily permitted. A thousand hours was considered to be 10 times the cumulative time that a pressure relief valve was likely to be blowing during the life of a boiler.

The second cause of the problem was the allowable primary membrane stress criterion of two-thirds of the yield stress. This is a reasonable criterion for primary membrane stress, but it appears inappropriate for a primary bending stress, which is what the pressure relief valve nozzle is subjected to when the valve is discharging. In the NB-3200 design-by-analysis rules for Class I Nuclear Power Plant Components, the allowable primary bending stress limit is 1.5 times the basic allowable membrane stress, i.e., it is $1.5S_m$ in recognition of the margin remaining before full yielding would take place in a rectangular cross-section subject to bending. In a cylinder subject to internal pressure, a 50% increase in a membrane stress of two-thirds yield would bring the cylinder to incipient yielding, with all fibers at yield stress. However, the onset of yielding at the extreme fiber of the same cylinder subjected to bending stress is not so serious because most of the cross-section is still well below yield stress. Depending on the shape of the cross-section, the design margin between the moment at initial yielding and the fully plastic moment can range from 20% to more than 50%. Moreover, the axial stress in a heavy pressure relief valve nozzle is so low that it was found to have very little effect in reducing the limit moment on the cross-section.

Based on these principles, Code Case 1876 incorporated allowable stresses for the design of pressure relief valve nozzles significantly higher than those normally used for design of other pressure parts. These stresses are provided for a relatively small number of materials commonly used for pressure relief valve nozzles and may only be used for the combined short-term loading condition of design pressure plus any forces and bending moments due to the discharge of the pressure relief valve. The nozzle and the vessel or header on which it is mounted must also be designed for design pressure alone, using the normal allowable stress given in Section II, Part D. As soon as Case 1876 was adopted, BPV I asked the B31.1 Section Committee to adopt a similar Code Case so that the same relief could be granted for the design of pressure relief valve nozzles mounted on boiler external piping. However, members of that committee expressed a number of concerns, which could never be resolved to their satisfaction, despite an ongoing dialog over more than a dozen years. Consequently, the design of pressure relief valve nozzles on main steam or reheat piping may utilize only the basic allowable membrane stress, increased by 20% for what B31.1 calls occasional loading. Such low design stresses sometimes result in very massive, thick-walled nozzles that present a number of difficulties when it comes to welding the much thinner pressure relief valve to the nozzle.

The members of BPV I's Subgroup on Design who have been involved in the development of Code Case 1876 believe that B31.1's rules are overly conservative. They cite the long record of satisfactory service of pressure relief valves with relatively thin walls and note that those walls are subject to the same bending and axial loads as the nozzles supporting the valves. The lesson here for the designer is to be very careful to use the nozzle design rules applicable to the location — boiler proper or boiler external piping — of the pressure relief valves. For the future, efforts to convince the B31.1 Section Committee to relax their rules for the design of pressure relief valve nozzles continue. The incorporation of Code Case 1876 into the text of Section I would require a special category of short-term allowable stresses in Section II, Part D, so BPVI may simply keep the case as a permanent one.

THERMOCOUPLE INSTALLATIONS

In large boilers, thermocouples are often used to measure temperatures of tubes and other pressure parts, and of water, steam, and flue gas. At some locations, such as the fireside of furnace tubes, it is so hot that a thermocouple installation on the surface would not long survive. To measure the metal temperature at or near the outside surface of such tubes, manufacturers resort to the use of a so-called chordal thermocouple, which is installed within the tube wall in a small hole drilled along a chord of the circle forming the outside surface of the tube. By using two such drilled holes, it is possible to install a thermocouple just at or below the hottest surface of a furnace wall tube and have the wires come out on the back face of the tube outside of the furnace. There, the temperature is low enough to permit installation of wiring to take the thermocouple signals to appropriate instrumentation in the control room or elsewhere.

The ends of drilled thermocouple holes on the furnace side of the tubes can be sealed by means of a silver solder designed for high-temperature service. Thermocouple assemblies consisting of a short length of tube with one or more chordal thermocouples installed some 4 to 6 in. apart are usually prefabricated for welding into furnace wall panels. A slightly different type of thermocouple installation is used to measure metal temperature near the inside surface of tubes or pipe. In such cases, the thermocouples can be placed in blind holes (drilled from the outside, but not all the way through the wall). For measuring fluid temperatures in headers or pipe, thermocouples can be placed in what are called thermowells — short, small-diameter closed-end tubes or pipes projecting radially into the pipe or header. The thermowells can be attached to the pipe by welding or by bolted flanges. In all of the thermocouple installations just described, holes have been drilled in the pressure parts. Since Section I is silent on the subject, designers may wonder whether any reinforcing or compensation is required for the affected components. In 1983, in response to just such a question, BPV I issued Interpretation I-83-60, Blind Drilled Holes for Thermocouple Wires:

Question: For Section I construction, is it permissible to drill isolated external holes not exceeding 0.13 in. (3.3 mm) in diameter to a depth of not more than half the wall thickness in fired superheater coils for the attachment of thermocouple lead wires?

Reply: Section I does not provide rules for blind drilled holes; see the second paragraph of the Section I Preamble.

As will be recalled from the discussion in the Introduction, the second paragraph of the Preamble places on the designer the burden of proof that any proposed new details of design and construction are as safe as those otherwise provided by the rules in the Code.

Let us consider how the designer might justify the various forms of thermocouple installation without providing any compensation. For chordal thermocouple installation, the diameter of the hole is very small. Although in theory this small hole has a slight weakening effect locally, analysis has shown that the hoop stresses due to internal pressure normally carried by the material removed for the thermocouple can easily be carried by adjacent material. If necessary, an Authorized Inspector might be persuaded that the installation was safe by the solution to a closely related but axisymmetric problem, which can be easily solved using finite element analysis. The analytical model used for the axisymmetric problem is a so-called long cylinder under internal pressure, with an annular hole whose diameter matches that of the hole drilled for the chordal thermocouple installation. The hole could be at midthickness of the cylinder wall or close to the outer surface without much change in the results. (Note: A long cylinder is one whose length is such that axisymmetric rotations or deflections at one end have little or no effect on the other end. An approximation for such a length is $l \geq 2.33 \sqrt{rt}$, where r is the radius, and t is the thickness of the cylinder. In the analytical model just described, the annular hole should be placed at midlength of a cylinder whose length is twice a long cylinder, so that end effects will have died out at midlength.)

If the average membrane stresses resulting from this model exceeded the allowable Section I design stress, they could be justified by showing them to be lower than stresses similarly determined for other configurations permitted by Section I, such as the $2\frac{3}{8}$ -in. (60-mm) diameter unreinforced opening in a shell permitted by PG-32.1.4. That configuration can be solved without much difficulty by using a 3D finite element program. Note also the concept of inherent reinforcement, i.e., rules for establishing the maximum size of an opening in a cylindrical shell for which no reinforcement is needed. Thus, a blind drilled thermocouple hole of perhaps an eighth of an inch (3 mm) in diameter is surely acceptable.

A similar approach could be used to justify a so-called blind drilled hole for a thermocouple. Again, note that the hole diameter is very small. For this situation, we can again invoke the Section I rule in PG-32.1.4, which permits unreinforced openings for threaded, studded, or expanded connections for which the diameter of the hole in the vessel wall does not exceed NPS 2 (DN50). By comparison, the thermocouple hole is much smaller. Moreover, it does not fully penetrate the wall. Another justification for a blind drilled hole can be found in Code Case 1998, Drilled Holes Not Penetrating through Vessel Wall, which permits blind holes up to 2 in. (50 mm) in diameter without reinforcing if the remaining thickness at the bottom of the hole satisfies the PG-31 design rules for a flat head. As discussed in Chapter 15, Determination of Allowable Stresses,

the design philosophy of Section I is based on the use of conservative values of average hoop membrane stress. Bending stresses and the effects of stress concentrations are not explicitly recognized, but the allowable stresses, design formulas, and details of construction permitted limit bending and peak stresses to a safe level. This has been demonstrated by a long, satisfactory record of experience. Thus, the effect of small holes drilled for thermocouples is seen to be a little different from the effect of other permitted details that increase stress above the average membrane stress. If any further justification is needed, it can be found in the long and successful record of typical thermocouple installation by boiler manufacturers.

PIPING DESIGN

INTRODUCTION

As explained in Chapter 4, under the heading Distinction Between Boiler Proper Piping and Boiler External Piping, Section I rules for the design of boiler proper piping are somewhat limited. They actually cover the design of pipe for internal or external pressure only. More extensive rules are provided in B31.1, Power Piping Code, applicable to the design of boiler external piping. Those rules cover, in addition to pressure, many other loads that piping might be subject to, such as mechanical loads that may be developed due to thermal expansion and contraction of the piping, impact loading, gravity loads, and seismic loads. Although such comprehensive rules are not provided by Section I for the design of the boiler proper piping, the boiler manufacturers over the years have managed to design this piping so that it serves its purpose in a satisfactory manner, often using design methods of B31.1. Designers of boiler piping, whether boiler proper piping or boiler external piping, are thus faced with a mixed bag of interrelated rules and should be aware of a number of special provisions and potential pitfalls that need to be considered. These are discussed in the following sections of this chapter.

Boiler external piping and boiler connections are described in PG-58. There are about 20 paragraphs explaining and defining BEP systems for drum-type boilers, isolable and separately fired superheaters, multiple boilers connected to a common steam header, high-temperature water heaters and forced flow steam generators. Section I provides five figures showing the schematics of the Code jurisdictional limits of piping for various piping systems.

Fig. PG-58.3.1(a) Drum-Type Boilers

Fig. PG-58.3.1(b) Isolable Economizer Located in Feedwater Piping and Isolable Superheaters
in Main Steam Piping

Fig. PG-58.3.1(c) Reheaters and Nonintegral Separately Fired Superheaters

Fig. PG-58.3.2 Forced-Flow Steam Generators With No Fixed Steam or Waterline

Fig. PG-58.3.3 Steam Separator-Type Forced-Flow Steam Generators With No Fixed Steam
or Waterline

These figures are provided in this chapter for the convenience of the reader.

SHOCK SERVICE FOR FEEDWATER AND BLOWOFF PIPING

There are two types of boiler external piping that are in a type of service called “shock service” — feedwater piping and blowoff piping, which, for all practical purposes, includes heat recovery steam generator superheater and reheater condensate removal piping addressed in PHRSG-3. Both types must be designed for a pressure higher than the MAWP of the boiler itself. The feedwater piping is close to the pump and is

potentially subject to pressure surges from it, especially if flow can be restricted by a valve somewhere in the flow path between the feed stop valve and the boiler. The blowoff piping can be subject to shock and vibration when the blowoff valves are opened, causing a flow-induced pressure drop in the blowoff line. Since the boiler water being discharged is at saturation temperature or close to it, the pressure drop can induce boiling within the blowoff line, with considerable vibration and shaking. The discharge of flashing liquid can also generate significant reaction forces on the blowoff pipe. To cover this shock service, the committee thought it prudent to add some safety margin to the design pressure used for feedwater and blowoff piping, thereby forcing the designer to make the walls somewhat heavier than would otherwise be required. The margin chosen was 25% of the MAWP, but not more than 225 psi (1550 kPa). This design rule is now found in B31.1, 122.1.3, and 122.1.4, and in PHRSG-3.3. Thus, for boilers whose MAWP exceeds 900 psi (6 MPa), the extra margin is a constant 225 psi (1550 kPa). When the MAWP is 2900 psi (20 MPa), approximately the highest MAWP of a natural circulation boiler, this represents a margin of only about 8%. However, this high-pressure piping is so strong (to resist the design pressure) that it does not need much additional margin for shock service.

Note that the zone of higher design pressure extends only for the length of the feedwater piping or the blowoff piping. For feedwater piping, this is typically from the upstream boundary of the boiler external piping at the feed stop or check valve to the end of the feedwater pipe where it is welded to an inlet nozzle on the economizer or, in the absence of an economizer, to an inlet nozzle on the drum. For blowoff lines, the zone of higher design pressure would extend from the end of the blowoff nozzle (which might be on a header at a low point on the boiler) to and including both valves normally required on a blowoff line. The result is somewhat unusual in that design pressure undergoes a step change at the junction of boiler external piping and the boiler proper, in the absence of any valve. A similar series of step changes in design pressure occurs in the case of forced-flow steam generators with no fixed steam and waterline that are designed for different pressure levels along the path of water-steam flow (see PG-21.2, PG-16.2, and Fig. PG-67.4).

PUMP DISCHARGE HEAD

The pressure developed by a boiler feed pump follows a typical pump curve, a head versus flow relationship in which, for any given speed, the pump discharge head varies inversely with feedwater flow. The pump designers choose a point along the curve as a design point, which for design pump speed establishes the design flow at the desired design pressure. At greater flow, the pump discharge pressure decreases. At reduced flow, the pressure increases, usually reaching a maximum—called the pump shutoff head—at or near zero flow, as would occur with a closed valve in the feedwater line. Pump pressure can be controlled by various means, such as varying pump speed or providing bypass/recirculation lines. Depending on the type of pump and its controls, the pump shutoff head can be considerably higher, perhaps 30% higher, than the pressure developed at full design flow. Such a pressure excursion could represent a significant overstress condition for the piping, valves, or other components between the pump and a closed block valve downstream.

The Power Piping Code, B31.1, deals with this potentially hazardous situation in 122.13, Pump Discharge Piping. That paragraph requires that the piping from the pump up to and including the valve normally used for isolation or flow control be designed for the maximum sustained pressure exerted by the pump and for the highest coincident fluid temperature, as a minimum. This is a logical and reasonable design approach. However, B31.1 relaxes this approach to some extent, by invoking the short-term overstress rules in 102.2.4, Ratings: Allowance for Variation from Normal Operation, which permit certain pressure and temperature excursions above their design values. These pressure or temperature excursions as applied to pump discharge piping are described in 122.13 as occasional and inadvertent, but they are permitted under three conditions, which cover almost anything that could happen:

- A. During operation of overpressure relief devices designed to protect the piping system and the attached equipment,

- B. During a short period of abnormal operation, such as pump overspeed, or
- C. During uncontrolled transients of pressure or temperature.

Note that it may not always be possible to take advantage of the so-called allowance for variation from normal operation; see discussion under the heading Short-Term Overstress in Boiler External Piping later in this chapter.

UNUSUALLY HIGH PIPING DESIGN PRESSURE

There are certain situations in which piping design pressure can significantly exceed the MAWP of the boiler. One which Section I fails to mention explicitly (although B31.1 does address the subject in 122.13, Pump Discharge Piping) is the presence of a stop valve somewhere in the flow path between the feed stop and check valves (which establish the upstream boundary of the boiler) and the boiler drum. If there are no valves between the feed stop valve and the drum, the safety valves on the drum provide overpressure protection for all upstream piping and components between the drum and that stop valve, such as feedwater heaters, or the economizer itself. However, sometimes a stop valve is installed downstream of an economizer, between the economizer and the drum, or an economizer is equipped with shutoff valves and bypass piping. [Such economizers are called isolable economizers, since they can be shut off from the boiler. See Fig. PG-58.3.1(b)].

With the valves on either side closed, an isolable economizer can become a fired pressure vessel, and Section I, PG-67.2.6 requires installation of a certain minimum pressure relief valve capacity to relieve the pressure caused by heating any water trapped within it. That relieving capacity, in lbs/hr (kg/hr), is calculated from the maximum expected heat absorption, in Btu/hr (W), as determined by the manufacturer, divided by 1000 (646). That capacity is relatively modest compared to the full capacity of the boiler feed pump. Consider now what would happen if the pump was started when the feed stop valve was open, but the stop valve downstream of the economizer was inadvertently left closed. The pressure in the feedwater line would quickly approach the pump shutoff head because the relieving capacity of the economizer pressure relief valve is so small compared to full flow. Pump shutoff head can exceed the MAWP of the boiler by 30% or more, depending on how much margin the pump designers have provided. This pressure would prevail from the pump to the stop valve downstream of the economizer. Components affected would include the feed stop and check valves, the feedwater piping, the economizer, and piping downstream of it up to and including the stop valve. Various means of dealing with this overpressure condition are discussed below.

A somewhat similar situation that could lead to an overpressure condition in the feedwater piping is described in PG-58.3.3. If feedwater heaters are installed between the feedwater stop valve and the boiler and those heaters are equipped with isolation and bypass valves, “provisions must be made to prevent the feedwater pressure from exceeding the maximum allowable working pressure of the piping or feedwater heater, whichever is less.” In this situation, if the wrong combination of valves were closed, all flow to the boiler could be blocked. The pump could then develop its full shutoff head, which would quite probably exceed the design pressure of both the feedwater piping and the feedwater heater. PG-58.3.3 continues with advice on how to solve this problem: “Control and interlock systems are permitted in order to prevent overpressure.” Such a method of providing overpressure protection is unusual (the Code in most cases requires pressure relief valves), but it is simply not feasible to provide enough pressure relief valves on the head of a feedwater heater to relieve the full flow of the boiler feed pump, which is somewhat greater than the full steam-generating capacity of the boiler. In fact, typical industry practice is to provide the tube side of feedwater heaters with only a small pressure relief valve on the head, intended to relieve the thermal expansion of trapped water. (Of course, in the absence of any isolation and bypass valves between the feedwater heaters and the drum, the pressure relief valves on the drum protect the heaters.) Thus, other means of protecting against overpressure are needed and permitted. An interlock system to prevent overpressure could involve a bypass with valves so arranged that the bypass valve must be open before the valve on the normal path can be closed. A control system might include one or more pressure-sensing controls that can reduce pump output as required, by reducing speed or by opening bypass or recirculation lines. Multiple controls could provide extra reliability.

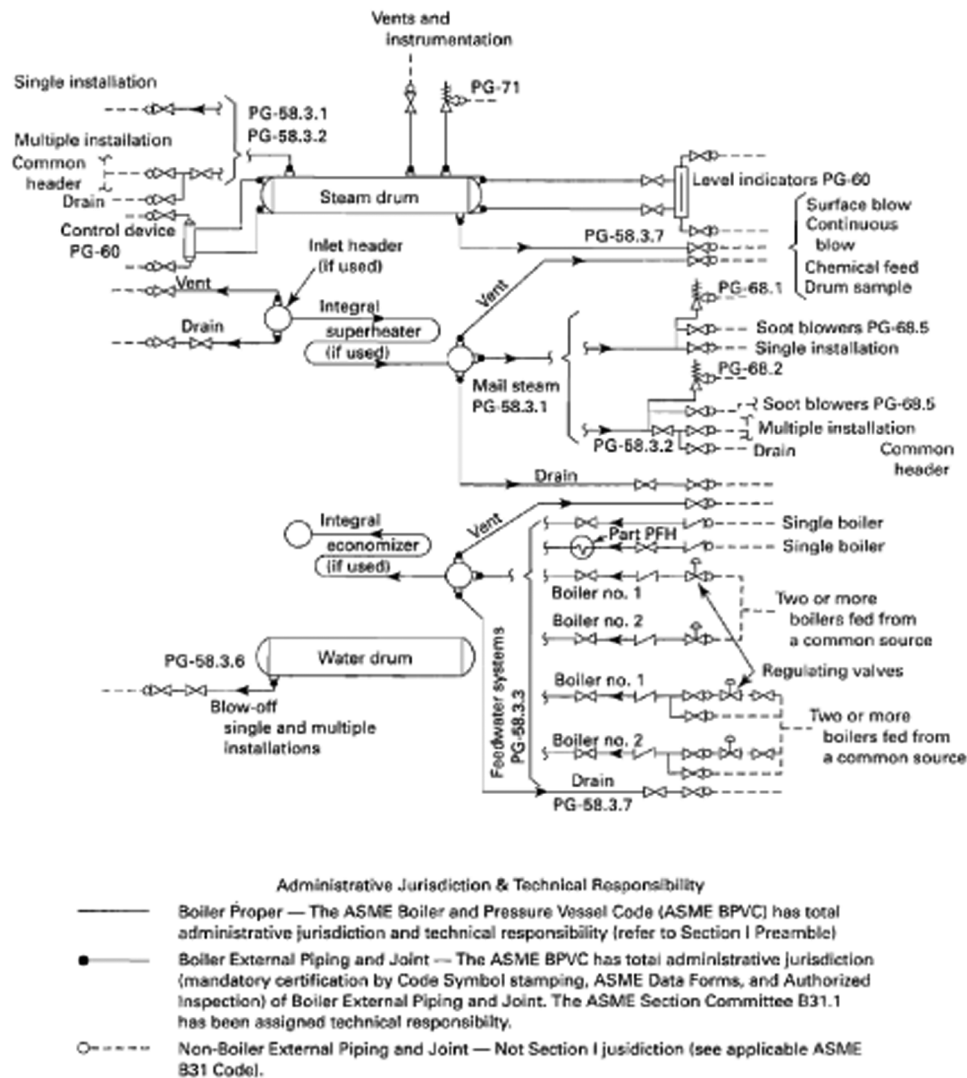


FIG. PG-58.3.1(a)
CODE JURISDICTIONAL LIMITS FOR PIPING-DRUM-TYPE BOILERS
(REPRODUCED FROM ASME SECTION I)

This design approach would also seem appropriate when feedwater heaters equipped with isolation and bypass valves are installed upstream of the feed stop and check valves and thus outside of Section I jurisdiction. In such a case, the above-mentioned pump discharge piping rules of 122.13 of B31.1, which permit short-term over-stress conditions, could reasonably be applied. The basis for these rules is explained in the following section.

SHORT-TERM OVERSTRESS IN BOILER EXTERNAL PIPING

An unusual and somewhat confusing aspect of piping design is a design approach now covered only in B31.1, 102.2.4, Ratings: Allowance for Variation From Normal Operation. This approach was formerly found in

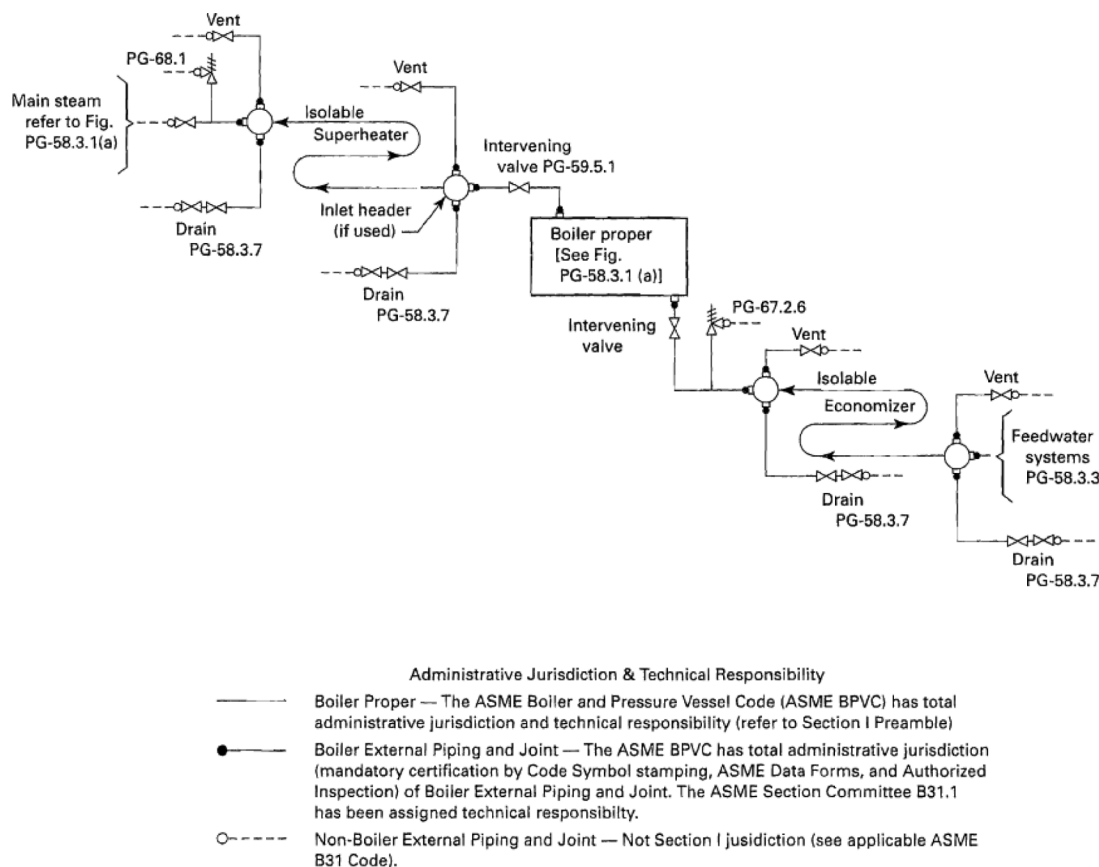


FIG. PG-58.3.1(b)
CODE JURISDICTIONAL LIMITS FOR PIPING — ISOLABLE ECONOMIZERS LOCATED
IN FEEDWATER PIPING AND ISOLABLE SUPERHEATERS IN MAIN STEAM PIPING
(REPRODUCED FROM ASME SECTION I)

Section I also, but was deleted in 1972, when the B31.1 committee was given responsibility for the construction rules governing materials, design, fabrication, installation, and testing of boiler external piping. The B31.1 committee subsequently modified that design approach, but it can sometimes still be used to overcome the pump overpressure problem just described. The essence of this approach is to permit short-term over-stress in the piping system caused by limited excursions in pressure and/or temperature above their nominal design values, i.e., above the maximum design capability of the pipe. The Section I version of this approach last appeared in PG-58.1.1.1 of the 1971 edition, as follows:

58.1.1.1 Variation in pressure and temperature of piping systems shall be considered safe for operation if the maximum sustained pressure and temperature on any part does not exceed the design pressure and temperature under this Section of the Code for all component parts of the system. It is recognized that variations in pressure and temperature inevitably occur and therefore the piping system shall be considered safe for occasional operation for short periods at higher than the design pressure and temperature.

Either pressure or temperature or both may exceed the design values if the stress in the pipe wall calculated by the formulas using the maximum expected pressure during the variation does not exceed the allowable S value for the maximum expected temperature during the variation by

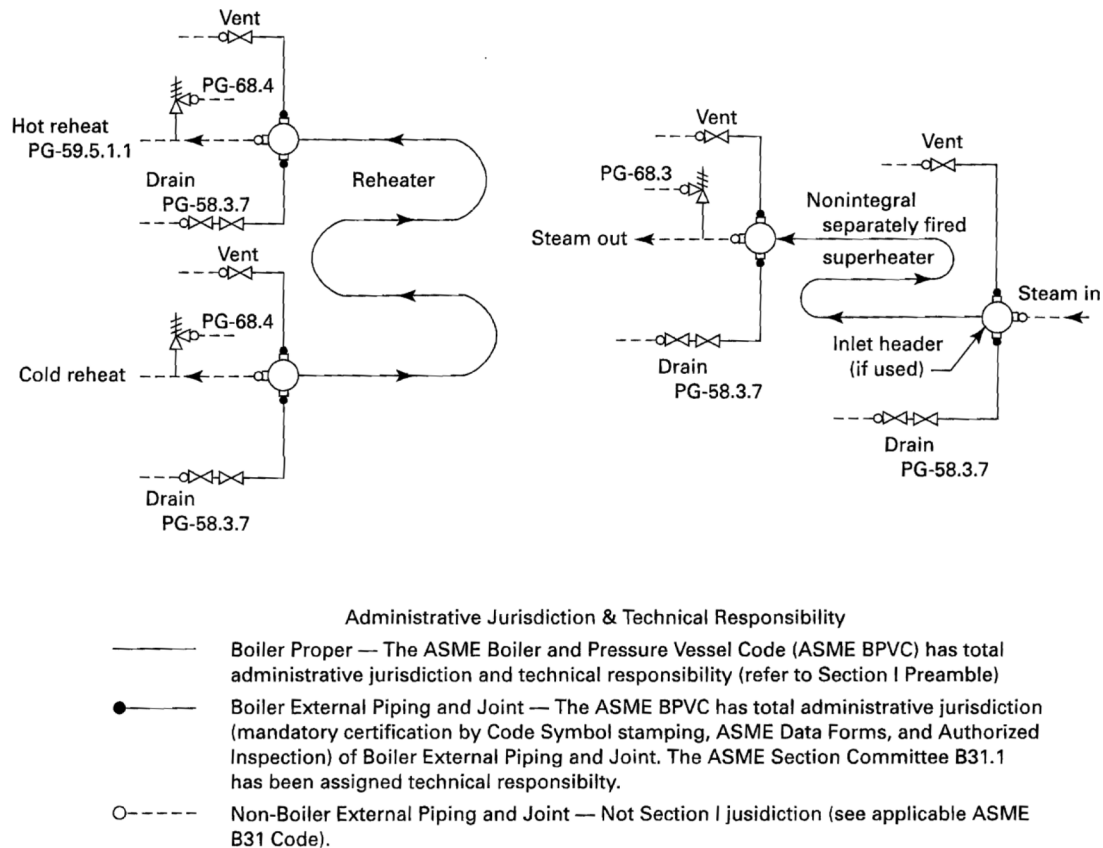


FIG. PG-58.3.1(c)
CODE JURISDICTIONAL LIMITS FOR PIPING — REHEATERS AND NONINTEGRAL
SEPARATELY FIRED SUPERHEATERS
(REPRODUCED FROM ASME SECTION I)

more than the following allowances for the periods of duration indicated:

58.1.1.1.1 Up to 15 percent increase above the S value during 10 percent of the operating period.

58.1.1.1.2 Up to 20 percent of the S value during 1 percent of operating period.

Until 1973, these Section I piping rules allowing short-term overstress applied explicitly to steam, feedwater, and blowoff piping, but it is not clear that they could not have been applied to any boiler piping. When the rules for design of boiler external piping were transferred to B31.1, the short-term overstress rules (which had long been in B31.1 also) became applicable to boiler external piping only and not to the boiler proper piping. As explained earlier, boiler external piping is a category that includes feedwater, main steam, vent, drain, blowoff, and chemical feed piping.

Some time in the 1970s, the B31.1 committee became aware that designers were taking advantage of the permitted short-term overstress for long periods of time. In one case, a designer argued that because a piping system had been designed for a 40-yr life, a 15% overstress condition was acceptable for 10% of 40 yr, or 4 yr, and no immediate correction in operating conditions was required. This was never the intent of the committee; the intent was to permit relatively short-term excursions for unusual overload or upset conditions, perhaps for a few hours or even days when power demand was very high, but not for so long that significant creep damage would accumulate if the piping (such as main steam piping) were operating in the creep range.

Accordingly, to close this loophole, or rather to reduce its size, the B31.1 committee added a time limit to these permitted excursions in pressure and temperature. Excursion time limits described vaguely as 10%

of the operating period and 1% of the operating period were changed to 10% or 1% of any 24-hr operating period. These rules have been further modified and now only permit a 15% overstress for no more than 8 hr at any one time and no more than 800 hr per year or a 20% overstress for no more than 1 hr at a time and no more than 80 hr per year. Those times represent a maximum of about 9% and 0.9% of the year, not very different from the 10% and 1% of the previous rule.

Still another modification of the rule permitting short-term temperature and pressure excursions occurred after some manufacturers of standard pressure parts (such as valves and fittings) realized that the Code was, in effect, saying that it was permissible to exceed the manufacturer's design stresses (inherent in the published pressure and temperature ratings of these standard components) by as much as 20%. The manufacturers objected, arguing with some justification that the short-term overstress rule reduced the manufacturer's design margins and imposed on the manufacturers implied warranties and liabilities they were unwilling to accept. The B31.1 committee was apparently persuaded by these arguments and modified the rules again. Minor editorial changes have been made since then. The version of the old Section I paragraph in the B31.1 2009 Addenda now reads as follows:

102.2.4 Ratings: Allowance for Variation From Normal Operation. The maximum internal pressure and temperature allowed shall include considerations for occasional loads and transients of pressure and temperature.

It is recognized that variations in pressure and temperature inevitably occur, and therefore the piping system, except as limited by component standards referred to in Paragraph 102.2.1 or by manufacturers of components referred to in Paragraph 102.2.2, shall be considered safe for occasional short operating periods at higher than design pressure or temperature. For such variations, either pressure or temperature, or both, may exceed the design values if the computed circumferential pressure stress does not exceed the maximum allowable stress from Appendix A for the coincident temperature by

- (A) 15% if the event duration occurs for no more than 8 hrs at any one time and not more than 800 hr/year, or*
- (B) 20% if the event duration occurs for not more than 1 hr at any one time and not more than 80 hr/year.*

Let us consider the two categories of component standards covered by the added clause. The first covers those piping component standards listed in Table 126.1 that do provide pressure and temperature ratings. The second covers those listed in Table 126.1 that do not provide pressure and temperature ratings. (Ratings of the latter, e.g., buttwelding fittings such as tees and elbows covered by ASME B16.9, are based on the rating of matching seamless pipe of the same material.) In other words, the inserted clause is intended to cover all standard piping components of Table 126.1. It is a warning that either the standards themselves or the manufacturers of those components whose standards do not have specific pressure and temperature ratings may limit or prohibit the use of the short-term overstress provisions of 102.2.4. In effect, B31.1 is saying do not exceed the ratings of the piping component standards.

Two very important and frequently used component standards among those found in Table 126.1 are ASME B16.5, Pipe Flanges and Flanged Fittings, and ASME B16.34, Valves—Flanged, Threaded, and Welding End. They are among several standards that provide pressure and temperature ratings. However, of all the component standards in Table 126.1 that provide pressure/temperature ratings, only one, the B16.34 valve standard addresses and limits any short-term overstress conditions caused by exceeding the published ratings. According to the standard, the operating pressure may exceed the rated pressure of a valve by no more than 10% when pressure-relieving devices are in operation. It then notes that “such conditions are necessarily of limited duration” and warns that “Pressure excursions in excess of the aforementioned are solely the responsibility of the user.” The standard also makes it clear that the valve manufacturers do not approve of any other pressure or temperature excursions above the established ratings, by making this statement: “Subjecting a valve to operating variances (transients) in excess of its rating is solely the responsibility of the user.”

The component standards that do not provide pressure and temperature ratings (but rather are designed to be as strong as seamless pipe of the same size and material) do not address the question of variances in the

pressure-temperature ratings. This leaves unresolved the question of what limits, if any, the manufacturers of such components might impose on short-term excursions. However, it would appear from the specific language of B16.34 that the user who subjects valves or fittings to pressure or temperature excursions above those permitted by the governing standards assumes the burden and responsibility of ensuring that the magnitude and duration of any excursions will not cause a significant reduction in safety or an excessive accumulation of creep damage for components operating at elevated temperature.

Since virtually all boiler external piping includes standard valves and fittings, it would, at first glance, seem that the changes to B31.1, 102.2.4 since 1973 have effectively blocked its use to permit any short-term excursions causing 15% or 20% overstress. However, this is not necessarily the case; the standard valves and fittings are chosen by pressure class, as explained in Chapter 11. These pressure classes (e.g., classes 600, 900, 1500, and 2500) are typically available in very large design pressure increments. For example, at 800°F (425°C), each successive pressure class has a pressure rating from 30% to 60% higher than the next lower rating. (See Table 2-1.1 of B16.34, the ASME standard covering flanged, threaded, and welding end valves, included in Appendix IV, Design Exercises.) It is likely, therefore, that valves with the lowest pressure class capable of sustaining any given design conditions may have a considerable design margin (either pressure, temperature, or both) above those conditions. Thus, a short-term excursion of pressure or temperature resulting in a permitted 15% or 20% overstress of the piping itself might not exceed the pressure/temperature rating of the particular pressure class of the valve(s) chosen for the boiler external piping.

As explained in the Introduction, Section I rules apply to the construction of new boilers. The same is true for the piping design rules of B31.1. That is, they too are new-construction rules. Thus, it seems odd that either code should contain any provisions that deal with the actual operation of the boiler, even to the point of saying how much overstress is permitted during short-term transients. However, the committees who develop the new-construction rules over the years have occasionally crossed the line that separates new construction from ongoing operation. We can speculate that these exceptions were justified as good advice based on experience or on a desire to warn about potentially unsafe conditions. Moreover, the rule writers of yesteryear worked in a less formal time, when apparently fewer objections were raised about including an occasional rule dealing with boiler operation. A Section I or Section VIII rule permitting short-term excursions above design conditions would probably not be approved today, on the grounds that such a rule has nothing to do with new construction and also that it would be virtually unenforceable, since it is often impractical to obtain and monitor a continuous record of the operating temperature and pressure for a large number of pressure parts. Moreover, Sections I and VIII presently provide no role for the Authorized Inspector once construction of the boiler or pressure vessel is completed, so there would be no third-party assurance that any pressure/temperature excursions stayed within the limits prescribed. Yet there are some B31.1 committee members who justifiably believe that the designer of a new piping system should give some recognition to the likelihood that it will inevitably be subject to temperature excursions and that the limits prescribed are useful in preventing premature creep damage.

HYDROSTATIC TEST OF BOILER EXTERNAL PIPING

The boiler external piping is given a hydrostatic test with the boiler, in accordance with PG-99 of Section I and 137.3 of B31.1, Power Piping, which simply invokes the rules of PG-99 and repeats the Section I requirement that an Authorized Inspector be present during the test. Figure PG-58.3.1(a) of Section I illustrates the Code jurisdictional limits for piping in drum-type boilers. That figure shows that the ordinary arrangement of the boiler feed shutoff valve (also called the feed stop valve) and the check valve is to have the latter upstream of the shutoff valve. However, in the case of a single boiler-turbine unit, PG-58.3.3 permits the order of these valves to be reversed, with the shutoff valve located upstream. During hydrostatic testing, that arrangement poses some minor difficulties that can be avoided by appropriate planning. When the feed stop valve is upstream of the check valve, it establishes the upstream boundary of the complete boiler unit. During the hydrostatic test, water is pumped into the system using some convenient connection, usually at a low point on the boiler, such as a drain line from a waterwall header. Since the check valve in the feedwater line will prevent any flow from

the boiler toward the upstream feed stop valve, some provision must be made to introduce the water upstream of the check valve, to ensure that all the feedwater piping is tested. This might be accomplished by removing the disk from the check valve during the test or by use of a temporary connection to bypass the check valve.

During the hydrostatic test, the closed feed stop valve defining the upstream boundary of the boiler and all other valves that establish the pressure boundary of the boiler have to be capable of withstanding a hydrostatic pressure of $1\frac{1}{2}$ times the maximum allowable working pressure of the boiler. Occasionally, this presents a problem. These stop valves are designed in accordance with the ASME B16.34 standard for valves. That standard's hydrostatic test requirements for valves differ from Section I requirements. B16.34 provides for two test conditions: one with the valve open, and one with the valve closed. In the open position, B16.34 requires the valve body (or shell, as the standard calls it) to be tested at $1\frac{1}{2}$ times its 100°F (38°C) pressure rating with no visible leakage through the pressure boundary walls. A valve body that can sustain a hydrostatic test at $1\frac{1}{2}$ times its 100°F (38°C) pressure rating is more than adequate to pass a hydrostatic test of the boiler, since valves on the boiler are designed for pressures at least as high or higher than the MAWP of the boiler, but at temperatures much higher than 100°F (38°C). Since the pressure rating of a valve declines with temperature (because the allowable stress declines with temperature), the 100°F (38°C) pressure ratings of all these valves are higher than their pressure ratings when the boiler is in operation at design temperature. Accordingly, the body of an open valve has no problem sustaining a pressure of $1\frac{1}{2}$ times the MAWP of the boiler.

When a valve such as a stop valve or check valve is designed for shutoff or isolation service [refer to Fig. PG-58.3.1(b)], B16.34 requires a closure test. In the closed position, the valve must be able to sustain a pressure equal to only 110% of its 100°F (38°C) pressure rating without significant leakage, as a test of the closure member. (Actual leak tightness requirements vary with the intended service and are not covered by B16.34, which advises that guidance on the subject may be found in MSS SP-61 or API-598.) Sometimes, the hydrostatic test pressure of $1\frac{1}{2}$ times the MAWP is too much for a valve in its closed position; that is, $1\frac{1}{2}$ times the MAWP is greater than 110% of the 100°F (38°C) pressure rating of the valve. For example, consider a feed stop valve for a boiler whose MAWP is 2900 psi (20 MPa). As described earlier under Shock Service, the design pressure for such a valve as part of the feedwater piping is 225 psi (1550 kPa) greater than the MAWP of the boiler, and the design temperature is the saturation temperature corresponding to the MAWP of the boiler. Accordingly, design conditions would be 3125 psi (27 MPa) at 691°F (365°C). For convenience in this discussion, the design temperature can be rounded up to 700°F (370°C).

Feed stop valves are normally made of the plain carbon steels that B16.34, the governing valve standard, designates as group 1.1 materials. Welding end valves are readily available in two pressure classes—standard class and special class. Table 2-1.1 of B16.34 (see Appendix IV) lists the pressure ratings (the maximum design pressure) of these two classes as a function of temperature. The table shows that either a 2500 standard class valve or a 1500 special class valve would meet the required design conditions [3125 psi (27 MPa) at 700°F (370°C)]. The 1500 special class, with its thinner walls, could be the design choice because it might cost less than the standard class valve. It happens though that the hydrostatic test pressure of the boiler in this example [$1.5 \times$ MAWP or 4350 psi (30 MPa)] exceeds the nominal capability of a 1500 special class valve in its closed position, which according to B16.34 need to be only 110% of its 100°F (38°C) pressure rating or 4125 psi (28.4 MPa). This is a rather small difference, only about 5%, and in all probability, the valve closure member and operating mechanism could sustain such a pressure without significant leakage. However, unless the valve manufacturer's agreement were obtained ahead of time, by the purchase specification, the manufacturer would be likely to disclaim any responsibility for the consequences of exceeding the normal limit of 110% of the 100°F (38°C) rating for a closed valve. Some further discussion on hydrostatic testing of boiler external piping is found in Chapter 7.

ALLOWABLE STRESS WHEN PRESSURE RELIEF VALVES ARE DISCHARGING

A basic principle in the Code design of pressure parts is that during operation of a boiler or pressure vessel, stresses due to internal design pressure are not allowed to exceed the maximum allowable stress values

(design stresses) listed in Section II, Part D. There are exceptions to this principle, such as when the pressure relief valves are discharging. Since the pressure in a natural circulation boiler is permitted to rise 6% above the maximum allowable working pressure when the safety valves are discharging (see PG-21.1 and PG-67.2), it follows that actual stress in components designed to the minimum required thickness could exceed the design stress by 6% under those circumstances. For forced-flow steam generators with no fixed steam and waterline that are equipped with automatic controls and protective interlocks responsive to steam pressure, the special overpressure protection rules of PG-67.4 apply. Those rules limit the pressure rise to 20% above the maximum allowable working pressure of any part of the boiler (any part other than the main steam piping, whose design pressure is sometimes lower than the rest of the boiler, as explained in the next section). In this type of boiler, groups of pressure parts are designed for different pressure levels along the path of water-steam flow, with the highest pressure at the economizer inlet and the lowest at the superheater outlet. Often, stop valves are installed in the water-steam flow path (see PG-67.4.4). These valves and any others used on the boiler external piping are usually selected to meet the ASME B16.34 valve standard, which provides tables of temperature and pressure ratings for various pressure classes and material groups, as explained in Chapter 11.

That valve standard contains provisions which permit an overpressure of only 10% when pressure relief valves are discharging, a value that is consistent with the overpressure permitted by Section VIII of the Code for vessels with a single pressure relief valve when that valve is discharging. The designer must therefore be careful that any valves chosen for use in a forced-flow steam generator with no fixed steam and waterline have sufficient margin in pressure rating to take care of the difference in overpressure capability provided by the valve standard (10% of its rating) and that potentially required by Section I (20% of the MAWP at the superheater outlet). However, as explained above under Short-Term Overstress in Boiler External Piping, the valve pressure classes usually available have large differences in their pressure ratings, so that the necessary margin to take care of the overpressure mismatch may already have been provided. That is, the lowest pressure class valve that meets the design pressure and temperature requirements may be able to sustain not only the design pressure required, but 1.2 times the so-called master stamping pressure, the design pressure at the superheater outlet (see PG-106.3).

FEEDWATER PIPING

Rules covering this piping are found both in Section I and B31.1, Power Piping. It is best to read both sets of rules carefully, since neither code covers all the requirements. Section I requirements for feedwater piping are stated in PG-58 and PG-59 and are illustrated in Figs. PG-58.3.1(a), PG-58.3.1(b), and PG-58.3.2. Figures 100.1.2(B) and (A-1) of B31.1 are equivalent. It shows the different valve arrangements required for a single boiler fed from a single source and for two or more boilers fed from a common source, with and without bypass valves around the required regulating valve. The required boiler feedwater check valve is typically placed upstream of the feed stop valve, except that on a single boiler-turbine unit installation, the stop valve may be located upstream of the check valve.

Note that the upstream boundary of the scope of Section I varies slightly depending on feedwater valve arrangements. This is shown by solid and dotted lines in Fig. PG-58.3.1(a) of Section I or its equivalent, Fig. 100.1.2(B) in B31.1. Changes in the Section I boundary can have some significance in the choice of design pressure for the feedwater piping and valves, which is governed by the rules found in 122.1.3 of B31.1. The rules call for a design pressure higher than the MAWP of the boiler, as described under the heading Shock Service for Feedwater and Blowoff Piping at the beginning of this chapter. They also stipulate, indirectly, a design temperature no less than saturation temperature corresponding to the MAWP of the boiler. The application of these rules is explained in Appendix IV, Design Exercise No. 3, Choice of Feedwater Stop Valve. Note also that a closed stop valve in the feedwater piping can cause the pressure upstream to rise to pump shutoff head. Design for this situation is addressed in 122.13 of B31.1 and is also discussed earlier in this chapter under Pump Discharge Head and Unusually High Piping Design Pressure.

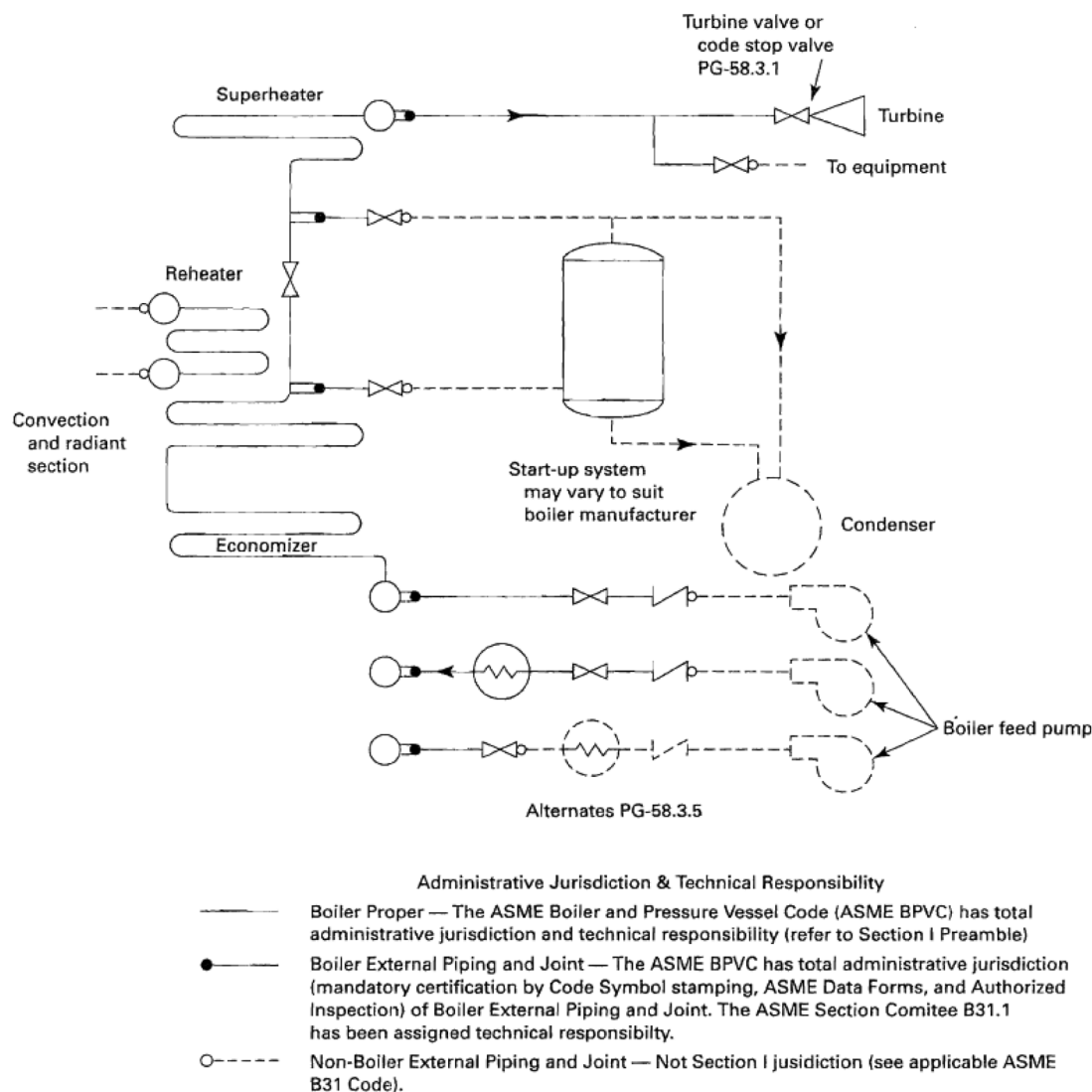
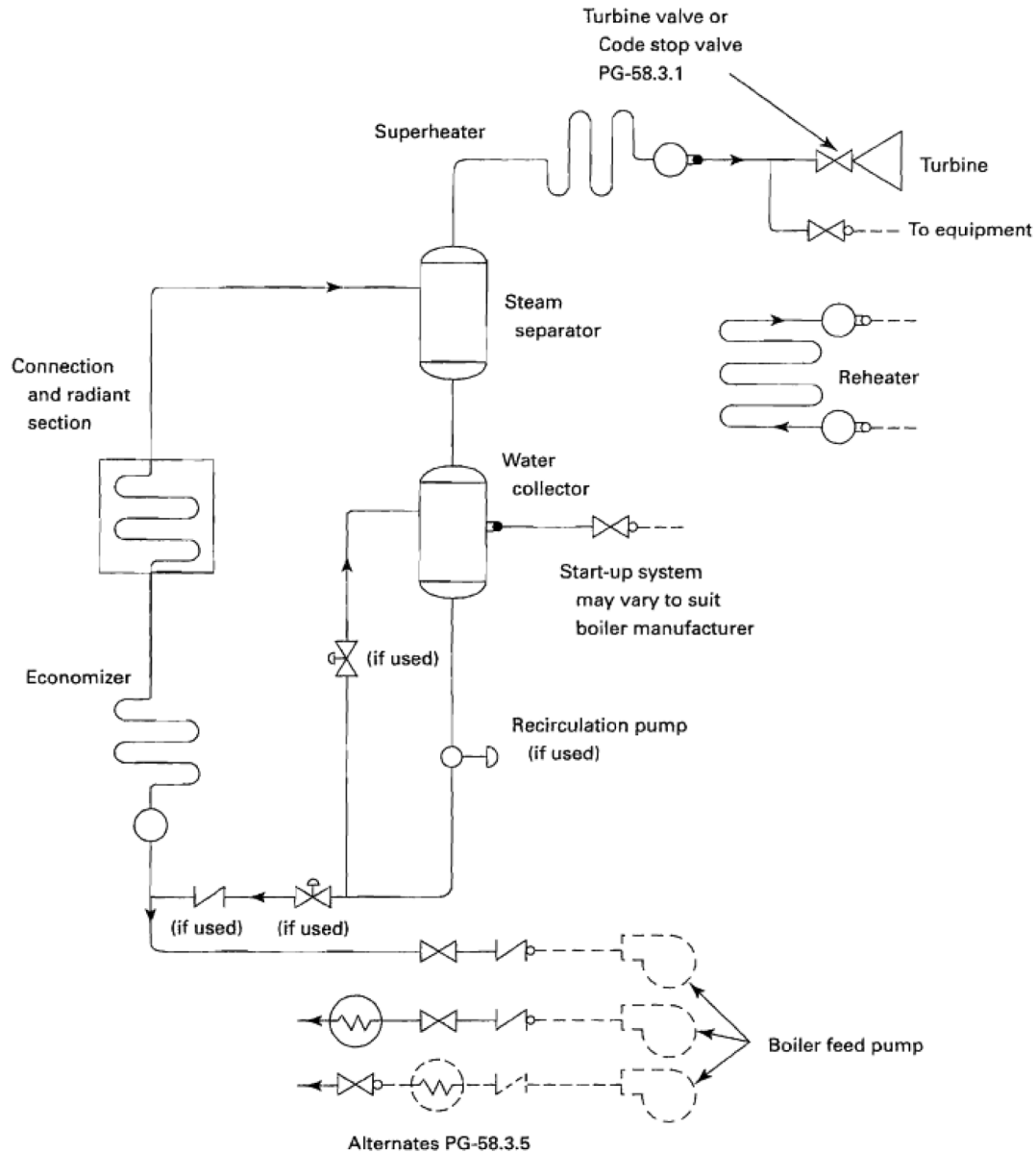


FIG. PG-58.3.2
CODE JURISDICTIONAL LIMITS FOR PIPING – AN EXAMPLE OF FORCED-FLOW STEAM
GENERATORS WITH NO FIXED STEAM OR WATERLINE
(REPRODUCED FROM ASME SECTION I)

One last requirement that is sometimes overlooked is found in B31.1, 122.1.3(C), which stipulates that the size of the feedwater piping between the boiler and the first valve upstream may be no smaller than the connection to the boiler.

MAIN STEAM PIPING

Main steam piping from the steam drum or from the superheater falls under Section I jurisdiction, but as explained in Chapter 4, this piping is *boiler external piping* (BEP), and the design rules for it are found in



ADMINISTRATIVE JURISDICTION AND TECHNICAL RESPONSIBILITY

- Boiler Proper – The ASME Boiler and Pressure Vessel Code (ASME BPVC) has total administrative jurisdiction and technical responsibility (refer to Section I Preamble).
- Boiler External Piping and Joint – The ASME BPVC has total administrative jurisdiction (mandatory certification by Code Symbol stamping, ASME Data Forms, and Authorized Inspection) of Boiler External Piping and Joint. The ASME Section Committee B31.1 has been assigned technical responsibility.
- Non-Boiler External Piping and Joint – Not Section I jurisdiction (see applicable ASME B31 Code).

FIG. PG-58.3.3
CODE JURISDICTIONAL LIMITS FOR PIPING — AN EXAMPLE OF STEAM SEPARATOR TYPE FORCED-FLOW STEAM GENERATORS WITH NO FIXED STEAM OR WATERLINE (REPRODUCED FROM ASME SECTION I)

ASME B31.1, 122.1.2, Steam Piping. There, five different situations are covered in A.1 through A.5, with these subparagraphs providing slightly different rules for each situation. It turns out that main steam piping can sometimes be designed for a pressure somewhat less than the MAWP of the boiler.

Subparagraph A.1 describes steam piping connected to the steam drum or to the superheater inlet header up to the first stop valve in each connection. Such piping is boiler external piping. An auxiliary steam line from the drum is also in that category. All of these lines contain saturated steam. The design pressure specified for such lines is not less than the lowest pressure at which any drum pressure relief valve is set to blow.

The design temperature for this piping is taken as the saturated steam temperature corresponding to the lowest pressure at which any drum pressure relief valve is set to blow. Although the low set drum pressure relief valve is ordinarily set at the MAWP of the boiler, this is not always the case. For example, it may be set lower to provide steam for a system not designed for the full MAWP of the boiler. Note that PG-67.3 of Section I requires only that one or more pressure relief valves be set at or below the maximum allowable working pressure.

Recall also that a steam line leading from a drum to an integral superheater (one connected directly to the boiler without intervening valves) is *boiler proper piping*. Piping design rules in that case are found in Section I. The design formulas of PG-27 would be used, with design pressure taken as the MAWP of the boiler. Section I actually provides no guidance as to choice of design temperature for such piping. Most designers would choose saturation temperature corresponding to the MAWP of the boiler, if the piping would not be absorbing heat. If the piping would be in a hot gas stream, the designer would calculate the maximum anticipated mean wall temperature and design for that temperature. The same design philosophy is seen in PG-27.4, Note 2, which advises on the choice of design temperature for tubes that do, and do not, absorb heat.

The next three subparagraphs of B31.1, 122.1.2 deal with the design of main steam lines coming from the superheater. This boiler external piping differs somewhat from steam piping connected directly to the drum, especially in being much hotter. For typical high-pressure utility boilers in the United States, main steam outlet temperature is nominally 1010°F (545°C), compared to saturated steam temperature of about 690°F (365°C) in the drum. Because of the high temperature of the main steam piping, plain carbon steel cannot be used; more expensive low alloy materials such as SA-335 Grade P-22 (2 1/4Cr-1Mo), or even austenitic stainless steel, are needed. At these higher temperatures, the pipe is operating in what is known as the creep regime, where time-dependent failure modes control the choice of allowable design stress. This allowable stress is less than half of the allowable stress used for the carbon steel drum plate, whose design temperature is only about 700°F (370°C). As a consequence, main steam piping is relatively expensive and thick-walled. In what may have been an attempt to minimize the required thickness of this hot piping, design rules have been evolved that, in some cases, permit the use of a design pressure somewhat lower than the MAWP of the boiler, in recognition of the fact that the steady, long-term operating pressure in the main steam line of a power boiler at full load may be as much as 10% below the MAWP of the boiler. Two factors contribute to this lower pressure. First, operating pressure in the drum is usually about 5% below MAWP, to avoid frequent lifting of the safety valves. Second, the pressure drop between the drum and the superheater outlet is often 5% of the MAWP.

Thus, a lower design pressure is permitted by the next paragraph of the B31.1 design rules for steam piping, 122.1.2 (A.2), which covers piping connected to the superheater outlet header up to the first stop valve. Design pressure is to be chosen as the lowest pressure at which any pressure relief valve on the superheater is set to blow, but not less than 85% of the lowest pressure at which any drum pressure relief valve is set to blow. It is customary to set the pressure relief valve on the superheater at a pressure low enough so that it will be the first to lift, thus assuring continued cooling flow of at least some steam through the superheater in the event of a turbine trip. The superheater pressure relief valve is usually set lower than the MAWP by slightly more than the pressure drop through the superheater, which is often about 5% of the MAWP for large utility boilers. Consequently, the design pressure of the main steam piping could be reduced by that amount, to the pressure relief valve set pressure. Design temperature is the expected steam temperature. This somewhat imprecise definition of design temperature was inherited when these paragraphs were moved from Section I in 1972. By comparison, the definition of design temperature found in B31.1, 101.3.2 is a better

one; it describes design temperature as the metal temperature representing the maximum sustained condition expected. The difference between these two definitions is probably not significant, but note that 101.3.2(c) requires design temperature of piping leading from fired equipment to be based on the expected continuous operating condition plus the equipment manufacturer's guaranteed temperature tolerance.

The next steam piping arrangement, described by B31.1, 122.1.2 (A.3), is a main steam line with two stop valves, used when two or more boilers having manhole openings are connected to a common header (see Section I, PG-58.3.2). A slightly lower design pressure is permitted for this most downstream portion of the main steam line, the piping between the two stop valves: the design pressure may be taken as the maximum sustained operating pressure, but not less than 85% of the lowest pressure at which any drum pressure relief valve is set to blow. Again, the design temperature is described as the expected steam temperature. The last of the three subparagraphs dealing with main steam lines, 122.1.2 (A.4), is probably the most recent of the three, since it describes large boilers installed on the unit system (i.e., one boiler and one turbine or other prime mover) and provided with automatic combustion control equipment responsive to steam header pressure. In this case, the design pressure is chosen as the highest of the following:

- the design pressure at the turbine throttle inlet plus 5%
- 85% of the lowest pressure at which any drum safety valve is set to blow
- the expected maximum sustained operating pressure at any point in the piping system

Design temperature is the expected steam temperature at the superheater outlet. Tacked on at the end of this paragraph is advice that the design pressure for steam piping for *forced flow steam generators with no fixed steam and waterline* is required to be no less than the expected maximum sustained operating pressure.

The last of the B31.1, 122.1.2 subparagraphs dealing with steam piping sets a minimum design pressure of 100 psi (700 kPa) for any steam piping that is boiler external piping. The purpose of this provision is to ensure some minimum mechanical strength in piping that might otherwise have paper-thin walls, were it to be designed for the MAWP of a very low pressure boiler.

Note that by using stipulations such as expected steam temperatures and expected maximum sustained operating pressure, B31.1 places the responsibility for establishing and justifying design temperature and pressure for steam piping on the designer. It is up to the designer to meet this responsibility by using recognized engineering principles and methods and prudent judgment.

BLOWOFF AND BLOWDOWN PIPING

Some of the requirements for blowoff and blowdown piping are found in Section I, PG-58 and PG-59, dealing with piping and piping connections to the boiler. Other requirements are found in B31.1, 122, Design Requirements Pertaining to Specific Piping Systems, and specifically in subparagraphs 122.1.4, Blowoff and Blowdown Piping; 122.1.7(C), Blowoff Valves; and 122.2, Blowoff and Blowdown Piping in Nonboiler External Piping. This rather odd state of affairs, having requirements divided between the two codes, is the result of the transfer of the boiler external piping rules from Section I to B31.1 in 1972. Although there is some overlap among these requirements, certain of them are found only in Section I, and others are found only in B31.1. Thus, it is necessary to study both codes carefully to ensure full compliance with the rather special rules that apply to blowoff and blowdown systems.

There is some confusion between the terms blowoff and blowdown, since they both refer to a process of discharging water from the boiler. PG-59.3.1 defines a **blowoff** as a pipe connection provided with valves located in the external piping through which the water in the boiler may be blown out under pressure. However, certain pipe connections that would apparently meet this definition are excluded from it, namely, "drains such as are used on water columns, gage glasses, or piping to feedwater regulators, etc., used for the purpose of determining the operating condition of such equipment." B31.1 in its definition adds drain piping to this list of pipe connections not considered blowoff, but imposes additional rules to help ensure that a drain line will not be used as a blowoff unless special valving is provided (see B31.1, 122.1.5, Boiler Drains, and the next section of this chapter).

The subtle distinction between a blowoff system and a blowdown system is explained in B31.1, 122.1.4: “**Blowoff systems** are operated intermittently to remove accumulated sediment from equipment and/or piping, or to lower boiler water level in a rapid manner. **Blowdown systems** are primarily operated continuously to control the concentrations of dissolved solids in the boiler water.” Note that the definition of a blowdown system has some flexibility. Such a system does not have to operate continuously, so long as that is its primary, or usual, mode of operation.

The importance of distinguishing between a blowoff and a blowdown system is that their design pressures and valving differ. There is also a maximum size of NPS 2½ (DN 65) imposed on blowoff lines. Blowdown systems require only a single shutoff valve and are designed for the MAWP of the boiler. Blowoff systems have unique double valving requirements and a design pressure higher than the MAWP because they are designed for so-called shock service, described at the beginning of this chapter. As explained there, boiler water being discharged through a blowoff is at saturation temperature or very close to it, and the flow-induced pressure drop in the Blowoff line can induce boiling within that line, resulting in considerable vibration and shaking. According to BPV I folklore, in the early days, an ordinary manually operated valve was used as a block valve on the blowoff line. Workers attempting to blow sediment out of the boiler might open the block valve a small amount, in an attempt to keep the process under control. However, there were instances when the vibration caused by the flashing discharge would suddenly shake the valve open, increasing the flow to such an extent that there was a danger of scalding any nearby workers.

To overcome this problem, rules were instituted in Section I long ago, rules now found in B31.1, 122.1.7(C.4) that require two valves on Blowoff lines for all but a few small electric boilers and other boilers whose MAWP does not exceed 100 psi (700 kPa). One of these two valves must be a so-called slow-opening valve. A **slow-opening valve** is defined as one “which requires at least five 360° turns of the operating mechanism to change from fully closed to fully open.” Such a valve is less susceptible to being shaken open. The designer may furnish either of the following two-valve arrangements: two slow-opening valves anywhere in the blowoff line or one ordinary stop valve (described as a quick-opening valve) at the nozzle connection on the boiler, followed by a slow-opening valve. The latter could be downstream at some location more convenient for the operator. Paragraph 122.1.7(C.10) also permits another valve arrangement, with the two required independent blowoff valves combined into a single body, but says nothing about which of the two (slow- or quick-opening) should be upstream. (It is difficult to understand what difference this choice would make.) Note that the boiler external piping, and thus Section I jurisdiction, extends out to and includes the second valve.

Further information on what Section I requires in the way of blowoff and blowdown systems is found in PG-58 and PG-59, which deal with boiler piping requirements. With the exception of forced-flow steam generators with no fixed steam and waterline and high-temperature water boilers, all boilers must have a bottom blowoff outlet in direct connection with the lowest water space practicable. There are maximum and minimum size limits imposed on the size of blowoffs: The maximum size is NPS 2½ (DN 65), and the minimum size is NPS 1 (DN 25), except for boilers with 100 ft² (9 m²) of heating surface or less, in which case the minimum is NPS ¾ (DN 20). Miniature boilers may have Blowoff connections as small as NPS ½ (DN 15). The reason for these size limits, as explained by old hands on BPV I, is that any size larger than NPS 2½ (DN 65) would discharge so much water so quickly that the natural circulation of the boiler could be upset. The minimum size was set to ensure that accumulated sediment could indeed be blown out. A smaller size was deemed adequate for miniature boilers. There is no maximum size specified for a blowdown connection, piping, or valves.

A perforated surface blowoff pipe is usually installed in the drum below the normal water level, for a number of purposes. This blowoff can be used to control the level of dissolved and/or entrained solids in the boiler water. (The dirty water discharged through the Blowoff is replaced with clean feedwater.) The surface blowoff can also be used as an auxiliary drum water level control if needed. PG-59.3.2 limits the size of this blowoff pipe to NPS 2½ (DN 65).

At most large boilers today, the water discharged from both the blowoff and blowdown systems is sent to a flash tank, where some of its energy is often recovered in the form of low-pressure steam for use in the

deaerators. The dirty water that collects at the bottom of the flash tank is then sent to an atmospheric tank, where more steam flashes off, and the remaining water can then be discharged to a sewer or to a facility for further treatment.

Further detailed requirements for blowoff and blowdown piping are given in the B31.1 paragraphs mentioned above. One of the pitfalls sometimes overlooked is a requirement that the size of the blowoff piping cannot be less than the size of the connection on the boiler. This is also the case for blowdown piping. Moreover, 122.1.7(C.3) requires that the blowoff valves themselves, the pipe between them, and the boiler connection must be the same size in almost all cases. There are also some special provisions in 122.1.7(C) on blowoff valves, prohibiting the use of valves with dams or pockets where sediment could collect.

DESIGN CONDITIONS FOR BLOWOFF AND BLOWDOWN PIPING

B31.1 also provides advice on what design temperature and pressure to use for blowoff and blowdown piping. The design temperature is the same for both. That temperature is the temperature of saturated steam at the maximum allowable working pressure of the boiler. This is a logical choice of design temperature, since the piping in question is attached to water-filled components of the boiler, and it is hard to imagine how the temperature of the water could ever exceed saturation temperature in the drum.

Design pressure for blowdown piping is required by 122.1.4(B.1) to be no less than the lowest set pressure of any pressure relief valve on the drum, which is usually the MAWP of the boiler, although it could be lower. As previously explained, blowoff piping is in shock service, and its design pressure is required by 122.4(A.1) to exceed the maximum allowable working pressure of the boiler by either 25% or 225 psi (1550 kPa), whichever is less, but may not be less than 100 psi (700 kPa).

DRAINS

PG-58 and PG-59 provide a great deal of information about piping arrangements and piping connections to the boiler and repeat many of the requirements that were transferred to the B31.1 Power Piping Code in 1972.

Among the various topics covered in these two paragraphs are the Requirements for Drains, in PG-59.4. This paragraph has three subparagraphs; the first of them, PG-59.4.1, lays down a general rule that all components of the boiler shall be provided with drains. That rule is as follows:

Ample drain connections shall be provided where required to permit complete drainage of all piping, superheaters, waterwalls, water screens, economizers, and all other boiler components in which water may collect.

The next two subparagraphs add further particulars about superheaters and high-temperature water boilers. The advice in PG-59.4.1.1 is that

Each superheater shall be equipped with at least one drain connection so located as to most effectively provide for the proper operation of the apparatus.

This is an instance of a Section I rule that either does not mean exactly what it says or by interpretation has come to mean something slightly different. For example, many large boilers are equipped with nondrainable superheaters. No one would ever think to raise a question about this arrangement, perhaps because a drain at the bottom of a pendant superheater would be completely impractical. (There is no way to keep such a drain cool enough to survive in the middle of the furnace with no flow through the drain connection.) Thus, it could be said that the drains normally provided on superheater headers *are* located so as to provide most effectively for the proper operation of the superheater, even though they cannot drain condensate that may collect in pendant loops.

With the above background in mind, consider the following situations which occurred in the 1970s and 1980s and which established a policy that there are exceptions to the rule that all boiler components must be drainable. In the mid-1970s, the states began to take a stronger stand on air pollution from industrial plants that had previously managed to fend off such regulation on the grounds that the industry and its jobs might leave if costly pollution control equipment were mandated. Finally, however, a certain state set a deadline for a large copper refinery to clean up the exhaust gases emanating from its smelter.

The most efficient way to effect the cleanup was to install a waste heat boiler to cool down the dirty gases sufficiently to send them to a scrubber. This solution also had the advantage of capturing some of the waste heat in those gases. The refinery engineers chose a type of boiler that had proven itself in similar service in Japan, Canada, and several states in the United States. The boiler was equipped with pendant water cooled surface within the furnace, comprised of vertical U-bend elements. The dirty gases passed over this surface, depositing most of their burden of particulate matter on it. Once during every shift, a rapping device was used to knock the slag deposits off the pendant elements for disposal.

Just as the addition of waste heat boilers and scrubbers was nearing completion, the Authorized Inspector for the organization assembling the boiler, the A stamp holder, challenged the lack of a drain on the pendant water cooled surface in the boiler. The Inspector invoked both the general rule of PG-59.4.1 requiring all components to be drainable and the particular rule of PG-59.3.4, which requires all water screens that do not drain back into the boiler to be equipped with outlet connections for a blowoff or a drain line.

The manufacturer of the boiler was unable to persuade the Inspector that it was both impractical and unnecessary to drain the pendant surface. The manufacturer cited the precedent of the pendant superheater with no drain, the fact that the boiler was to be installed in a heated building where there was no danger of freezing the water in the pendant surface, the successful application and acceptance of this design in other jurisdictions, and the feasibility of draining the boiler by using compressed air to blow the water out if necessary. The Inspector insisted that he would accept the boiler and sign the Data Report Form only if BPV I issued a ruling that a drain was not needed for the pendant surface. The manufacturer had no choice but to bring his case to BPV I. Moreover, the inquiry had to be carefully phrased so that the committee would perceive it as a general question and not as a request for a ruling on a particular design. As is often the case, the committee modified the inquiry somewhat, in the interest of making the published reply as broadly useful and informative as possible. The following Interpretation was issued in 1977 as Interpretation I-77-16, under the heading Section I, PG-59, Drain and Blowoff Requirements:

Question: The design of a forced circulation waste heat boiler for a copper refining process incorporates vertical U-bend elements in the waterwalls and in pendant heating surface above or within the furnace. The pendant design is specifically desired for this application to facilitate mechanical rapping for slag removal. The individual elements are necessarily undrainable.

A continuous blowdown connection from the steam drum is used for control of boiler water concentration. Further, the design provides a bottom blowoff connection from the lowest water space available in the main downcomer (circulating pump suction) piping. In addition, drain valves are provided for the circulating pump discharge header and for the inlet and outlet upper headers from which the nondrainable boiler elements are suspended.

Are these provisions for blowoff and drain connections adequate to meet the requirements of Section I?

Reply: It is the opinion of the Committee that the blowoff connection as described satisfies the requirements of PG-59.3 provided the size and type of blowoff valves meet the special Section I requirements for such service. The various drain connections as described in the inquiry will meet the intent of PG-59.4 if so arranged as to permit draining all the boiler piping and headers except for the vertical U-bend elements.

Both original authors were participants in the deliberations which lead to the above interpretation and believe it made sense. It was practical. Moreover, it was philosophically consistent with the words in the Preamble referring to forced-circulation boilers, boilers with no fixed steam and waterline, and high-temperature

water boilers. The Preamble exempts such boilers from the requirements for “accessories that are manifestly not needed or used in connection with such boilers.” Further support for this interpretation also can be found in B31.1, 122.1.5(A), Boiler Drains, which begins: “Complete drainage of the boiler and attached piping shall be provided *to the extent necessary* to ensure proper operation of the steam supply system.” (Italics were added by the authors for emphasis.) The drainage arrangements described in the inquiry did meet this criterion, as evidenced by the successful operation of that boiler and many others like it.

The committee again ruled on the issue of drainability on January 3, 1980 in Interpretation I-80-01, under the heading: Section I, Blowoff Requirements, PG-59.3 and PG-59.4. Although ostensibly about blowoffs, this interpretation provides further evidence that the committee does not believe it is necessary to be able to drain the water by gravity from every component. The boiler in question was an unusual one; it generates steam in so-called bayonet tubes, a tube-inside-a-tube arrangement in which water flows down the inner tube and up through the annular space between the inner and outer tube, where the steam is generated. It is clearly not feasible to provide either a drain or a blowoff at the bottom of each individual tube. The inquirer sought guidance on how he might deal with this situation with the following explanation and questions:

These inquiries apply to a drum boiler equipped with vertical bayonet tubes suspended from the drum. Water is force-circulated down the inner tube and up through the annular space between the inner and outer tube.

Question: *May a threaded cap at the bottom of the each boiler tube serve as the drain required in PG-59.4?*

Reply: *No. A drain is defined as a pipe connection with a valve or valves as stipulated in PG-58.3.7. The individual bayonet tubes need not necessarily be drainable, and alternate means of removing the water in these tubes could be employed if the designer so chooses.*

Question: *Must an external blowoff pipe be provided for each boiler tube?*

Reply: *No. PG-59.3.3 requires only a single “bottom blowoff outlet in direct connection with the lowest water space practicable.” The blowoff connection and its valve or valves must comply with the provisions of PG-58.3.6.*

In the above Interpretation, the committee extended the policy first enunciated in Interpretation I-77-16 regarding drains and blowoffs, namely, that it is not absolutely necessary to drain by gravity every individual element in the boiler. Moreover, the single blowoff required has always been described as an “outlet in direct connection with the lowest water space practicable.” Since it is not practicable to provide a blowoff on individual tubes, a regular blowoff from a water space somewhere low on the boiler, such as a waterwall header, would suffice.

There is another Interpretation dealing with the issue of drainage. That Interpretation is I-83-98, Section I, Drains for Horizontal Axis Helical Coil Forced Flow Steam Generators. It reads as follows:

Question: *Certain forced flow, no fixed waterline steam generators used for oil field steam flooding service are constructed with helical coils on a horizontal axis. It is impractical to provide complete drainage by gravity of each of these coils. Is such drainage required by PG-59.4.1?*

Reply: *No.*

Question: *What drain provisions are considered necessary to comply with PG-59.4.1?*

Reply: *Ample drains must be provided to permit drainage of all boiler piping and headers. Alternative means of removing the water in the helical tubes may be used.*

Still another inquiry on the subject of drains was answered by BPV I on March 9, 1992 as Interpretation I-92-27, Requirements for Drains, which reads as follows:

Question: *Do the drain requirements of PG-59.4 require an economizer or superheater to be drainable by gravity?*

Reply: *No. Alternative means of removing the water may be used.*

By these rulings, the committee again showed that it is willing to take a practical approach in accepting new boiler designs as they are developed for new applications, so long as the fundamental safety features of

the boiler are unimpaired. In the opinion of the authors, drainage by gravity is not a fundamental safety feature. Other means of coping with undrainable water are available if necessary. A start-up procedure known as a boil-out is typically employed to eliminate trapped or condensed water in pendant- or platen-type superheaters and reheaters.

The above discussion dealt with the fundamental issue of drainability. There are other requirements pertaining to drains and drain piping, which are found in Section 1, PG-59.3.4 and PG-59.4, and in B31.1, 122.1.5. The latter paragraph stipulates that a drain line intended for use both as a drain and a blowoff must be designed as a blowoff, with the requisite double valving. If the drain is intended for use only when the boiler is not under pressure, a single shutoff valve is acceptable, provided it can be locked closed or can be blanked off on the downstream side. Finally, 122.1.5(A) stipulates that the pipe, fittings, and valves of any drain line may not be smaller than the drain connection on the boiler. This is probably to prevent constrictions downstream of the drain connection which might prevent prompt drainage of the boiler.

DESIGN CONDITIONS FOR DRAIN PIPING

Advice on the design conditions to be used for drain piping is given in 122.1.5(E). This advice is somewhat confusing, in that it introduces a discussion of “remaining piping” and how to design it. [That remaining piping is apparently nonboiler external piping (NBEP) beyond (downstream of) the valve on the drain line that defines the boundary of Section I jurisdiction. Minimum design conditions of pressure and temperature are stipulated for this nonboiler external piping as 100 psi (700 kPa) and 220°F (105°C).] Paragraph 122.1.5(E) goes on to say that the drain piping and valves that are part of the boiler external piping are to be designed for the same temperature and pressure as the drain connection on the boiler proper. The latter is usually a welded nozzle. Boiler manufacturers design these nozzles for the MAWP of the boiler at the design temperature of the components to which they are attached. If the nozzle were a threaded nozzle and thus part of the boiler external piping, the design pressure and temperature would logically be the same as for the components to which the nozzle was threaded.

PIPE CONNECTIONS TO THE BOILER

Both Section I and B31.1 address the question of the type of connections that may be used to attach piping to the boiler proper, in their respective paragraphs PG-59.1 and 122.1.1(D). Section I rules are brief: Boiler external piping must be attached by a tapped opening, a bolted flange, or by a butt or socket weld. PG-59.1.1.4 goes on to say that boiler proper piping may be expanded into grooved holes and seal welded if desired. It also stipulates some special rules for the attachment of blowoff connections for firetube boilers. These old rules were intended to facilitate the replacement of such connections without welding.

B31.1, 122.1.1 (D) addresses the connections of boiler external piping to the boiler and echoes the Section I rules with some amplification. Additional B31.1 rules are as follows:

- Nonferrous pipe or tubes are limited in size to NPS 3 (DN 80).
- Hub-type flanges may not be cut from plate material because of the possibility that any laminations in the plate uncovered by machining might open up when bending stresses are applied to the flange. (Section I actually has an identical provision in PG-42.3.)
- Slip-on flanges shall not exceed NPS 4 (DN 100).

Finally, B31.1 paragraph 122.1.1 (H) allows the use of American National Standard socket welded flanges in piping or boiler nozzles, provided the dimensions do not exceed NPS 3 (DN 80) for Class 600 and under and NPS 2½ (DN 65) in Class 1500. This advice is slightly inconsistent with similar provisions for socket welded connections in Section I, PW-41.5, which has no pressure limitations, but provides more detailed

design rules. B31.1 is silent on what size Class 900 socket welded flanges may be used; an NPS 2½ (DN 65) limit is implied.

ADDITION OF SMALL CONNECTIONS TO BOILER PIPING

There is an unusual provision in 100.1.2(A), the Scope paragraph of B31.1, Power Piping, covering boiler external piping. That provision reads as follows:

Pipe connections meeting all other requirements of this Code but not exceeding NPS ½ may be welded to pipe or boiler headers without inspection and stamping required by Section I of the ASME Boiler and Pressure Vessel Code.

First, note that any boiler external pipe connections to the boiler do, as a matter of course, meet all other requirements of B31.1, Power Piping (all other than inspection and stamping). Thus, the piping should be perfectly satisfactory to serve as power piping, since design, material, and construction are adequately covered by B31.1. The B31.1 waiver of inspection and stamping applies only to small pipe—NPS ½ (DN 15) and smaller, such as might be used for instrumentation connections—that appears to be boiler external piping. The waiver also applies only to small connections welded to pipe or boiler headers (but not explicitly to the drum). Moreover, Section I already waives stamping, but not inspection, for pipe NPS 2 (DN 50) and smaller (see PG-109.2). It thus seems that this special provision might prove useful only for the addition of small instrumentation connections as an afterthought, perhaps after the Authorized Inspector has completed his or her inspection. What seems unusual is that by 100.1.2(A), B31.1 is apparently waiving Section I rules; however, there is a comparable provision in Section I, PW-41.3, which states that pipe connections not exceeding NPS ½ (DN 15) may be welded to pipe or headers without the inspection normally required by Section I. Presumably all other Section I rules would still apply. It thus appears that both Section I and B31.1 at one time decided that the rules normally requiring inspection of welded pipe connections could be relaxed for these small lines and coordinated their respective rules.

FABRICATION

FABRICATION

Fabrication is not specifically defined in Section I, but it is generally understood to mean all those activities by which the manufacturer converts material (plate, tube, pipe, etc.) into completed boiler components. Such activities include welding, bending, forming, rolling, cutting, machining, punching, drilling, broaching, reaming, and others. Section I permits the manufacturer very broad latitude in fabrication because of the wide variations in manufacturing practice, machinery, and trade methods.

Section I provides only a limited number of general rules for fabrication in PG-75 through PG-82. (One widely used method of fabrication, tube expanding, has surprisingly few rules provided in Parts PWT and PFT. Welding, perhaps the most widely used and controlled method, is covered extensively in Part PW. A discussion of both methods is given in the next section of this chapter.) The general rules for fabrication in Part PG specify tolerances for drums and ellipsoidal heads and limit certain cutting, drilling, and punching processes such that subsequent machining will remove all metal whose mechanical and metallurgical properties have been affected by the earlier process.

The manufacturer is permitted to repair defects in material, provided acceptance of the Authorized Inspector is first obtained, both as to method and extent of repairs.

TUBE ATTACHMENT BY EXPANDING

Each year, thousands of watertube and firetube boilers are constructed using one of the oldest boiler making fabrication methods — tube expansion. As early as 1880, William Miller Barr devoted several pages to the subject of tube expansion in his book titled [A Treatise on High Pressure Steam Boilers](#). He explained that “Tubes less than five inches diameter are expanded by special tools into plain smooth holes” and act to a lesser degree “as stays by the slight ‘bead’ or riveting over of the tubes on the outside of the heads.” He wrote about the Prosser method (still used today) saying that tubes “put in by this method” are “expanded on both sides of the tube plate in one operation” and “tend to greatly stiffen the head.” He also discussed “Dudgeon’s roller tube expander,” explaining that it expanded the tube by “means of a continuous rotary pressure” resulting in the mitigation of “the liability of splitting the tubes by driving in a conical or other expanding drives.” Surprisingly, Mr. Barr also said that by using the roller expander, leaking tubes “can be tightened, with steam on the boiler, with perfect safety.” (Ah, the good old days!)

It is fair to say that the treatise authored by Mr. Barr was never intended to be a code for boiler design and construction. Because of its lack of details regarding the expansion process, it is also reasonable to think it provides an insight into how much the manufacturers of that era relied upon knowledge gained from their

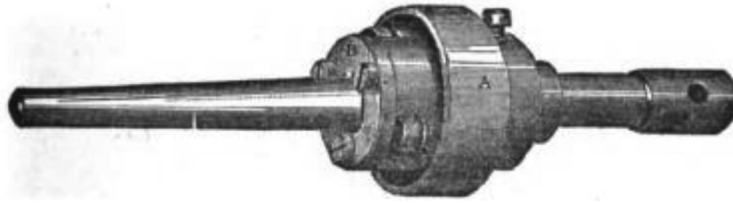


FIG. 6.1
DUDGEON'S ROLLER EXPANDER, CIRCA 1880

own manufacturing experience as well as the skills of the craft persons they employed. This is not entirely different from today's manufacturers and might explain why, to this day, there are relatively few rules regarding this tried and true fabrication method.

In Part PWT, rules in PWT-11 explain that a combination of expanding, flaring, beading, and welding may be used provided the methods are applied in a certain order:

- expanded and flared;
- expanded and beaded;
- expanded, flared, seal welded, and re-expanded after welding;
- expanded, seal welded, and re-expanded after welding, or first seal welded and then expanded after welding; or
- expanded only provided the tubesheet thickness is 0.625-in. (16-mm) thick and the tube hole has one or more rounded or square profile grooves normal to the hole axis.

The rules also address minimum and maximum tube projections, flaring dimensions, rounding of tube hole edges, and seal weld throat thickness. PFT-12 describes similar rules for expanded connections. Such connections shall be:

- expanded and beaded;
- expanded and beaded and seal welded; or
- expanded and seal welded.

Those connections that combine expanding and welding must be expanded after welding. The reason for this requirement in both PWT and PFT is to eliminate gaps between the tube and the tubesheet hole caused by expansion and contraction inherent with the welding process.

The rules described above are good general rules, but they do not provide all the answers to questions that arise when manufacturers and assemblers utilize the tube expanding process. First, there is the question regarding the types of expansion methods allowed or restricted. This particular question was answered by the third question and reply of Interpretation I-07-06 issued in March, 2008.

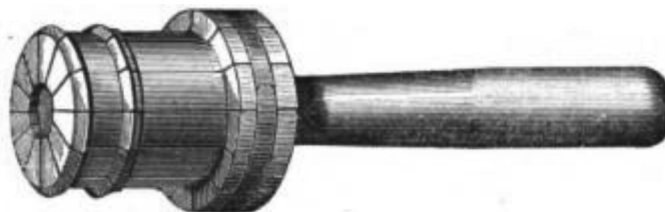


FIG. 6.2
PROSSER TUBE EXPANDER, CIRCA 1880

Question (3): *May manufacturers use tube expansion methods other than roller expanding, such as hydraulic, explosive, or combinations of methods in which the uniform pressure expansion precedes roller expanding (hybrid expanding) in the construction of firetube boilers built in accordance with Section I, PFT-12?*

Reply (3): *Yes.*

This interpretation is in keeping with the second paragraph of the Preamble which states “*The Code does not contain rules to cover all details of design and construction. Where complete details are not given, it is intended that the Manufacturer, subject to the acceptance of the Authorized Inspector, shall provide details of design and construction which will be as safe as otherwise provided by the rules in the Code.*” There are many issues related to tube expansion not addressed by code rules. The following are examples of such issues that must be addressed by manufacturers, either by personal experience or by collective knowledge shared by the craft personnel performing the work.

- Tube material — Certain tube material is better suited for expanding than others (SA-192 versus SA-210, for example). A contributor to Steam Forum (www.steamforum.com) noted that he was barely able to achieve the “required” tube wall reduction because the tube material, SA-210, was less ductile than expected. The same situation can occur when a cold swaged tube is not heat treated after swaging.
- Finish — The holding strength of the expanded joint will likely be greater when the tube end and tube hole ID have a “satin finish” as opposed to a smooth, polished surface. Finishing the tube and tube hole should be done in a radial direction, not axially.
- Eccentricity — Out-of-round tube holes require more working to provide a tight joint. Selecting the equipment best suited for this situation mitigates the problem.
- Proper Expansion — Another way of phrasing this is “how much tube wall thinning is adequate?” A general rule of thumb is that a 10% tube wall reduction is “ideal,” but a range of 7% to 12% is good. Again, experience and good engineering judgment play a key role in providing sound, tight expanded joints.

When one considers all the uncontrollable variables involved with the tube expanding process, one can better understand why the Code has not provided more detailed rules. While it is one of, if not, the oldest boiler making process still being used in the construction of power boilers, it has yet to be automated. As long as it is used, the process will most likely remain highly dependent on the manufacturer’s personal experience and the collective skills of the craft personnel executing the process.

WELDING — SOME HISTORY

An important factor in the evolution of today’s efficient high-pressure boilers was the development of welding as a replacement for the riveted construction used in the 19th century and the first half of the 20th century. Although welding was already in use in 1914 when the first Edition of the ASME Code was in preparation, no mention of welding appeared in that Edition because the method was not considered sufficiently reliable. The use of gas and electric welding for steel structures and ships was brought before the Boiler Code Committee at its first meeting after the adoption of the Code, in 1915, but the Committee, though interested, took no action. In 1916, the Committee responded to a request for consideration of welding from the Union Iron Works of California, stating that it had under observation all sorts of welding of pressure vessels and had asked welding experts to write papers for the ASME to bring out further information on these various processes. Further requests were received for permission to use the rapidly evolving art of welding, and when the first Edition of the Code was revised in 1918, paragraph P-186 permitted fusion welding, but only when stresses were carried by other construction and safety did not depend upon the strength of the weld.

An ASME Subcommittee on Welding was appointed in 1918, and in 1920, several societies involved in welding formed the American Welding Society (AWS). Utilizing government-sponsored research on welding

that had been motivated by the recent war effort, these groups formulated the first rules for fusion-welded boilers. The first rules for joining pressure boundary materials by welding appeared in 1923, in the Low Pressure Heating Boiler Code, the predecessor of today's Section IV. The first Edition of Section VIII, then called Unfired Pressure Vessels, was published 2 years later, in 1925. It also contained limited rules for welding, but it was not until the late 1920s and early 1930s that fairly comprehensive rules for welding appeared in both Sections VIII and I. A separate book section on the *qualification* of welding was first published in 1941, entitled Section IX, Welding and Brazing Qualifications.

An important aspect of welding, compared to other means of construction, is the absolute need for careful control of the welding process in order to achieve sound welds. The ASME Code attempts to achieve this control by allowing welds to be made only by qualified welders using qualified procedures. Section IX provides the rules by which the welders and the weld procedures may be qualified. However, there are many other aspects of welded construction besides qualification, and rules covering these other aspects are found in other ASME book sections covering welded constructions (Sections I, III, IV, VIII, and XII).

The ultimate goal of welding procedure and performance qualification is to achieve a weldment whose properties are at least the equivalent of the base material being joined, as demonstrated by certain tests. Qualification of the procedure establishes that the weldment will have the necessary strength and ductility when it is welded by an experienced welder, one who has demonstrated his or her ability to deposit sound metal when following that procedure. Qualification of the welder establishes that he or she can deposit sound weld metal in the positions and joints to be used on production welding.

With the explicit exception of the rules of PG-26, Weld Strength Reduction Factor (see Chapter 4, Design), an assumption implicit in the welding rules of Section I is that a weld is the equivalent of the base material it joins; accordingly, a properly made weld does not weaken the vessel. Consequently, there are no rules prohibiting superimposing attachments on welds or having nozzles or other openings placed where they intersect welds. This is stated explicitly in PW-14. There is also no rule that would prevent a manufacturer from making an opening for a nozzle in a vessel, then deciding the nozzle is not needed, and replacing the material removed for the opening with a properly designed and welded patch.

Note: A number of different terms are used in this chapter to describe various types of welders and welding. The following generally accepted definitions of those terms are provided for general information:

- A **welder** performs a manual or semiautomatic welding operation.
- A **welding operator** operates machine or automatic welding equipment.
- In **manual welding**, the welder controls and performs the entire welding process by hand.
- In **machine welding**, the equipment performs the welding under the constant observation and control of the welding operator.
- In **semiautomatic arc welding**, the equipment controls only the filler metal feed, and the advance of the welding is manually controlled.
- In **automatic welding**, the equipment performs the welding without adjustments of the controls by the welding operator.

WELDING RULES

Most of Section I welding rules are found in Part PW, Requirements for Boilers Fabricated by Welding. Part PW provides rules specifically applicable to boilers and their components and simply refers to Section IX for the qualification of the weld procedures and the welders. The rules for welding of boiler external piping (as opposed to boiler proper piping) are not found in Section I; they are found in B31.1, Power Piping. Power Piping also invokes Section IX for the qualification of weld procedures and welder performance, but is somewhat more liberal with respect to the transfer of procedures and welders from one organization to another.

Among the many aspects of welding covered by Part PW are these: responsibilities of the manufacturer or other organization doing the welding; the materials that may be welded; the design of welded joints;

radiographic and ultrasonic examination of welds and when such examination is required; the welding of nozzles; attachment welds; welding processes permitted; qualification of welding; preparation, alignment, and assembly of parts to be joined; the use of backing strips; advice on preheating; requirements for postweld heat treatment; repair of weld defects; exemptions from radiography; the design of circumferential joints; the design of lug attachments to tubes; duties of the Authorized Inspector related to welding; acceptance standards for the radiographic and the ultrasonic examination required by Section I; preparation of test plates for tension and bend tests; and welding of attachments after the hydrostatic test. The remainder of this chapter is devoted to discussion of these topics.

QUALIFICATION OF WELDING PROCEDURES

It is a general rule under any section of the ASME Boiler and Pressure Vessel Code and the ASME Code for Power Piping, B31.1, that all welding must be done by qualified welders, using qualified welding procedures. With some exceptions, every manufacturer (or other organization doing the welding, such as an assembler or parts manufacturer) is responsible for the welding it does. Also, with such exceptions as the use of AWS Standard Welding Procedures allowed by Section I and the interchange of WPS and welders allowed by B31.1, every manufacturer is responsible for conducting the tests required by Section IX to qualify the welding procedures used and the performance of the welders who apply those procedures. Section I stipulates these responsibilities in PW-1.2.

The qualification of a welding procedure is a process in which the manufacturer prepares certain documentation, known as a **Welding Procedure Specification (WPS)** and a **Procedure Qualification Record (PQR)**, which documents and supports the WPS. The WPS comprises a set of instructions, primarily for the welder (but also for the Authorized Inspector), regarding how to make a production weld to Code requirements. These instructions are written in terms of certain parameters applicable to the welding process that are called essential, nonessential, and when required, supplemental essential variables (see below). A WPS lists the essential and nonessential variables, and the acceptable ranges of some of these variables when using the WPS. The WPS must also reference the Procedure Qualification Record (PQR) that supports it. Often, more than one PQR is used to support a WPS.

The PQR is a formal record of the welding data (the actual value of the variable recorded during the welding of the test coupons) for each welding process used and the results of the mechanical test specimens cut from those coupons. Nonessential variables used during the welding of the test coupons may be recorded at the manufacturer's option. The tests (usually tensile and bend tests) are used to demonstrate that a weldment made using the WPS has the required strength and ductility for its intended application. Various other tests are sometimes used instead of the bend and tensile tests. All of these rules are more fully explained in QW-140 and QW-202 of Section IX. The variables used in production welding may vary somewhat from those used during the welding of the test coupons. Note that the purpose of the procedure qualification test is just to establish the properties of the weldment, and not the skill of the welder, although it is presupposed that the welder performing the procedure qualification test is a skilled welder.

QUALIFICATION OF WELDER PERFORMANCE

To complete the qualification process for welded construction, performance tests must be conducted for each welder or welding operator to establish the welder's ability to deposit sound weld metal. Each manufacturer is responsible for conducting the tests to qualify the performance of its welders in accordance with its qualified welding procedure specifications. (QW-300.2 of Section IX states that this responsibility cannot be delegated to another organization, but that prohibition had, until 2009, been modified by the series of Section I interpretations described below under the heading Transfer of Procedures and Welders to Another Organization.) The purpose of making each manufacturer responsible for qualifying

its own procedures and welders is to assure they can produce an acceptable weldment, using those procedures.

In general, the **Welder Performance Qualification (WPQ)** is accomplished by having the welder weld test coupons. The welder may then be qualified by mechanical bend tests of specimens cut from performance test coupons or by volumetric examination (RT, UT) of a test coupon or the welder's initial production weld. For certain types of welds, such as fillet welds, stud welds, resistance welds, and corrosion-resistant weld overlay, volumetric examination is not an appropriate test, and other tests are substituted. These include fracture tests, macro-examination, torsion tests, metallographic examination, and liquid penetrant examination. Particulars of these tests may be found in QW-100 and QW-200 of Section IX.

The WPQ must list the essential variables, the type of test and test results, and the thickness and diameter range qualified for each welder and welding operator. The **range qualified** is a convenient term applicable to some essential variables used in both procedure and performance qualification. For example, a WPS is qualified for welding base materials up to a certain thickness only, depending on thickness, T , of the test coupons welded. Similarly, a welder is qualified to deposit weld metal up to a certain thickness only, depending on the thickness, t , of weld metal he or she deposited in making the test coupons. Long experience has shown that a weld procedure that can be qualified using a test coupon of a given thickness will produce satisfactory weldments for a base metal thickness somewhat greater, or lesser, than that used in the test coupon. Similarly, a welder who has shown by a performance test that he or she is capable of depositing sound metal of a given thickness is also capable of depositing sound weld metal that is either thicker or thinner than the welder deposited in making the test coupon. Based on this concept, Section IX has developed tables QW-451 and QW-452, which establish thickness ranges for production welding based on procedure and performance qualifications.

For procedure qualification, Table QW-451 defines the range of thickness of base metal qualified as a function of the thickness of the test coupon welded and the maximum thickness of deposited weld metal qualified as a function of the thickness of weld deposited in making the test coupon. These tables contain so many different test coupon thicknesses and weld types that any generalization about thickness ranges qualified could be misleading. However, in many cases, the range of thickness of base metal qualified by a particular procedure is twice the thickness of the test coupon welded, and the maximum thickness of deposited weld metal qualified when using a particular weld process is twice the thickness of the weld metal deposited in using that process to make the test coupon.

For performance qualification, Table QW-452 defines only the thickness of deposited weld metal qualified as a function of the thickness of the weld metal deposited in the test coupon. Base metal thickness qualified is not a consideration in performance qualification. For groove welds, welding a test coupon less than ½-in. (13-mm) thick qualifies the welder to weld twice the thickness he or she deposited in making the coupon. If the coupon thickness is ½ in. (13 mm) or greater, the welder is qualified to deposit weld metal of any thickness. This seems quite reasonable, since if a welder can make a satisfactory weld ½-in. (13-mm) thick, he or she could presumably make a thicker one with no difficulty.

When welders are qualified, identification marks are assigned to them, so that all welded joints can be identified as to who made them. PW-28.4.1 describes ways of identifying welds, subject to the acceptance of the AI. The welder can stamp his or her mark on or adjacent to the welds, or the manufacturer may keep a record of welded joints and the welders who made them. This is discussed further under Welding Documentation, below.

EXPIRATION AND RENEWAL OF WELDING QUALIFICATIONS

As a general rule, once a welding procedure specification is qualified, it remains qualified. After first cautioning the reader to take provisions of other Code sections into consideration, QW-100.3 of Section IX explains that weld procedure specifications, procedure qualification records, and welder performance records made in accordance with the requirements of the 1962 (or later) Edition may be used in any construction

built to the ASME Boiler and Pressure Vessel Code and the ASME Code for Power Piping. These WPS, PQR, and WPQ do not have to be amended to include any variables required by later Editions and Addenda. However, the qualification of any new weld procedures or the requalification of any existing procedures or welders must be in accordance with the requirements of the Edition of Section IX in effect at the time of the qualification.

In contrast to the permanence of the WPS, the skills a welder demonstrates during performance qualification can be diminished or lost if they are not used. Accordingly, QW-322 of Section IX, Expiration and Renewal of Qualification, stipulates that if a welder or welding operator has not welded with a process for 6 months, his or her qualifications for that process expire. The general rule is this (as usual, there are some exceptions): If during the 6-month period prior to his or her expiration of qualification a welder uses a manual or semiautomatic welding process, the welder maintains his or her qualification for that process and extends it for another 6 months. Thus, it is important for a manufacturer to maintain careful records for each welder, so that if possible, sufficient welding to maintain the welder's qualifications can be scheduled, thereby avoiding the not inconsiderable cost of requalification.

These costs as well as the impact on productivity due to the need to requalify welders drew more and more attention in the mid to late 1980s. It was during this period that production of new field assembled boilers declined significantly and the maintenance and repair of existing boilers greatly increased. Field assembly of a large utility type boiler typically takes from 10 to 18 months, whereas scheduled maintenance and repair work lasts from 3 weeks to 4 months. It was relatively easy for a welder to maintain his or her qualifications for a contractor while on long-term new construction, but typically lost his or her qualifications when working maintenance and repair outages. This was exacerbated by the fact that the welder may work for several different contractors over the course of a year, rarely working for a single contractor for more than several weeks.

In the late 1980s, a group of boiler contractors met with their customers to discuss how costs could be reduced and productivity increased. One approach pursued as a result of that meeting was to hold multiple welder performance qualification tests witnessed by representatives of each of the contractors. Each representative witnessing the test completed and signed a welder performance qualification test record (WPQ). The contractors also agreed to provide welder continuity records. This allowed the welder to go from one contractor for which he or she was qualified to another for which he or she was qualified without having to requalify, even if the welder had not welded with a process for the second contractor for over 6 months. Of course, this being a new approach to welder qualification, it was questioned whether it met Code requirements. To clarify Section I rules, BPV I issued interpretation I-89-50:

Question 1: In accordance with PW-28 and PW-1.2, can several contractors or assemblers simultaneously conduct performance qualification test(s) of a welder?

Reply 1: Yes.

Question 2: In accordance with PW-28 and PW-1.2, can a welder simultaneously weld performance qualification test coupons in accordance with Welding Procedure Specifications of several contractors or assemblers when the essential variables are documented as identical?

Reply 2: Yes.

This interpretation helped pave the way for the Section IX rules addressing this concept. QW-300.3 was issued in the 1992 Addenda of Section IX. It explains that more than one manufacturer, contractor, or installer may simultaneously qualify one or more welders provided certain rules are followed. Each participating organization must be represented by a responsible employee during the test. The WPS to be followed during the test shall be compared and must be identical for all essential variables (except for preheat and post weld heat treatment). As an alternative, the participating organizations can agree to use a single WPS provided each organization has PQR to support the WPS. The representative must identify each welder, perform the required examinations and tests and complete and sign a WPQ for the welder. When a welder changes employers, the new employer shall verify that the welder's continuity of qualification has been maintained.

Approval and issuance of QW-300.3 is an excellent example of how the Code Committee considers the needs and successful practices of the Code user community and responds by formulating rules to assure consistent application by all who choose to apply the alternative rules. It is worth noting an example of the successful application of these rules. In 1988, an organization consisting of boilermaker employers called the National Association of Construction Boilermaker Employers decided to establish an independent, not-for-profit corporation to facilitate the process that would eventually be described by the Section IX rules found in QW-300.3. This corporation, Common Arc Corporation, now facilitates the simultaneous welder performance qualification test sessions, maintains copies of welder process continuity records provided by the participating contractors, and distributes this data to the participating contractors. At this writing, more than 200 contractors and 13,000 welders participate in the program. It is fair to say that BPV IX confirmed its confidence in the rules of QW-300.3 when, in the 2008 Addenda, QW-322 was revised to require a welder to use the welding process under supervision of the qualifying manufacturer or **a participating organization described in QW-300.3**.

QW-322 also provides for the revocation of a welder's qualifications for a particular welding process for cause; that is, when there is a specific reason to question the welder's ability to make welds using that process. All other qualifications not questioned remain in effect. Such a revocation might occur if a welding supervisor or the AI noticed obvious evidence of unsatisfactory welding. Under these circumstances, a welder must requalify using a test coupon "appropriate to the planned production work." Successful testing of the coupon in accordance with QW-301 and QW-302 restores the revoked qualifications. In the case of a welder whose qualifications to use a particular process have expired because of a 6-month lapse in use, the qualifications can be restored if the welder welds a single test coupon of plate or pipe, of any material, thickness, or diameter, in any position and that coupon passes the qualification tests originally required (by QW-301 and QW-302). Renewal of qualification may also be done on production work provided the requirements of QW-304 and QW-305 are satisfied. Successful testing renews the welder's previous qualifications for that particular welding process for those materials, thicknesses, diameters, positions, and other variables for which the welder was previously qualified.

TRANSFER OF PROCEDURES AND WELDERS TO ANOTHER ORGANIZATION

For various reasons, procedure and performance qualification tests are ordinarily not transferable from one manufacturer to another. That is, a welder who has been qualified by one manufacturer to use a procedure qualified by that manufacturer cannot switch employers and continue to weld using that same procedure unless the new employer has also qualified the procedure and the performance of the welder. However, in 1948, a modification of this policy was introduced, apparently at the request of the heating and piping contractors of the day. According to Committee minutes of that time, the heating and piping contractors had been transferring welders and WPS as was allowed for other piping systems and did not see the need to change just because of the placement of a valve (i.e., the boundary point of the boiler external piping). They even pushed for changing the rules of Section I to end Section I jurisdiction to the first inlet and first outlet of the boiler (similar to current Section VIII rules). After due consideration, the Committee included in the Summer 1947 Addenda to the 1946 Edition of Section I a new paragraph, P-116, and a new reference to P-116 at the end of existing paragraph P-112. The latter stated that the requirements for "welded external piping (not a part of the boiler circulation and beyond the outlets of the boiler)" were now to be found in P-116. When the text of Section I was completely reorganized and its paragraphs renumbered in the 1965 Edition (with no change in technical content from the previous version), P-116 became PW-28.5, with only slight editorial change. That paragraph gave the following advice:

To avoid duplication of qualification tests, it is recommended that procedures, welders, and welding operators qualified as required above be acceptable for any similar welding work on piping using the same procedure (see PW-1.2).

This recommendation was, until the 2010 Edition of Section I, a source of contention from the day it first appeared. First of all, until the acceptance of AWS Standard Welding Procedure Specifications in the 1998 Edition 2000 Addenda, it contradicted the rules of PW-1.2 that required each manufacturer to be responsible for qualifying its own weld procedures and the performance of its welders. Also, it raised an interesting question: does a recommendation waive a requirement? Based on interpretations of this paragraph, the answer is yes. In February 1978, BPV I issued Interpretation I-78-06, which explained what it had in mind when it wrote PW-28.5. Here is the essence of that interpretation:

The intent of this paragraph is to provide for the avoidance of duplication of qualification tests of welding procedure specifications, welders, and welding operators as they apply to piping within the scope of Section I.

Manufacturers or contractors are permitted to join together with other manufacturers or contractors into an organization for the establishment of welding procedure specifications and their qualification so that the individual manufacturer or contractor does not have to duplicate this effort. This means that a welding procedure specification adopted by the organization must be qualified in accordance with Section IX of the Code by a member of the organization. Other members of the organization may subsequently use the welding procedure specification without requalification.

Welding procedure qualification test records shall be available with each welding procedure specification sent to the organization's membership.

No member of the organization may use the organization's qualified welding procedure specifications on ASME Code work unless he holds the applicable ASME Code Stamp and Certificate of Authorization.

Welders and welding operators of a member manufacturer or contractor must pass their performance test on each of the organization's welding procedure specifications they are to weld under, except as otherwise permitted in Section IX. The performance qualification test records are placed on file with the organization. When such welders or welding operators are employed by another member manufacturer or contractor, their performance qualification records are made available to their new employer by the organization and performance requalification is not required for those welding procedure specifications under which they qualified previously.

It is incumbent upon the member manufacturer or contractor using the organization's welding procedure specifications and performance qualification records to assume responsibility for the qualifications by maintaining records, certified by him, and available to the Authorized Inspector.

Note that PW-28.5 recommended that previously qualified procedures and welders be acceptable for "any similar welding work on piping." Yet subsequent Interpretations I-81-17 and I-92-09 extended that recommendation from welding on piping to welding on any product form that may be used for construction under PW-41, i.e., any kind of circumferential welding on cylindrical product forms.

In 1996, BPV I tried to delete PW-28.5 on several grounds. The first was that this paragraph was originally aimed at welding of boiler external piping, and rules for such welding since 1973 have been found in B31.1, Power Piping. Accordingly, any recommendation in Section I about qualification of procedures and welders for such piping is inappropriate and redundant. Moreover, BPV I was largely opposed to the idea of allowing someone other than the manufacturer to qualify the procedures and welders to be used for welding components of the boiler proper. The proposal to delete PW-28.5 was approved by BPV I; however, it was defeated at the next approval level, the Board of Pressure Technology Codes and Standards. At that level, board members who believed that procedures and welders proven satisfactory for boiler external piping are also appropriate for the boiler proper were able to muster the minimum number of votes to block the action. This position was reversed in the 2010 Edition when, once again, BPV I approved the deletion of PW-28.5.

The action to delete PW-28.5 was precipitated by another request to clarify the rules. Attempts to revise the paragraph to clearly state the intent failed. Explaining that PW-28.5 is a continuing source of confusion regarding qualification of WPS and welders for work on boiler external piping and the boiler proper, and

that the rules described in PG-109.1 and PW-28.4 are clear in that regard, BPV I took action to delete the paragraph. In a separate, concurrent action, BPV I issued the following interpretations:

Question I: *Do the rules of B31.1 for welding procedure and welder performance qualification apply to welding of the boiler external piping defined by ASME Section I?*

Reply 1: *Yes.*

Question 2: *Do the B31.1 rules described in Question 1 above apply to welded joints in the boiler proper?*

Reply 2: *No.*

With these interpretations acting as the “final nails in the PW-28.5 coffin,” it should now be clear that the rules of B31.1, paragraph 127.5.3, Qualification Responsibility, apply only to the boiler external piping.

During the often contentious debates regarding whether prequalified WPS and welders should be allowed to be used on other than boiler external piping, many Committee members who were strongly opposed to the practice conceded that experience with prequalified procedures had generally been satisfactory when used on the most common materials. (Note that the same was not true for welders.) However, they argued that an organization that obtains prequalified weld procedures from others may have insufficient knowledge of welding metallurgy to avoid the many potential problems of welded fabrication. Among such problems and concerns are the effects a variation in the composition of the materials to be welded might have on their hardenability, and thus their weldability, and what remedial measures, such as preheat or postweld heat treatment, might then be appropriate. These committee members also believed that requiring welder performance qualification by each new employer would achieve better results than permitting one manufacturer to rely on performance testing supposedly carried out by another organization. Some manufacturers shared a related view; if they are to be held responsible for their welding, they want to conduct their weld procedure qualifications and their own welder performance qualifications, rather than relying on others.

In 1995, the Committee convened a task group consisting of representatives of BPV IX, I, III, IV, VIII, XI and B31. The task group was charged with reviewing the ANSI/AWS Standard Welding Procedure Specifications (SWPS) and reporting, from a technical and quality control perspective, on their usability within the boiler and pressure vessel code. As a result of the review, the task group reached the conclusion that the SWPS met the WPS requirements of Section IX; however, the task group members also concurred that the SWPS may not address the additional requirements of the construction codes. To address this issue, the task group recommended that the user of a SWPS be required to document all additional requirements of the construction code to be used with the SWPS. This and other task group recommendations were approved by Section IX and Section I, which incorporated rules relating to SWPS into the 1998 Edition 2000 Addenda.

The Section IX rules are found in QW-100.1 and require that WPS used by a manufacturer or contractor be a WPS that has been qualified in accordance with Article II, or an AWS SWPS listed in Appendix E and adopted by the manufacturer or contractor in accordance with Article V. In a process similar to the way base materials are treated (i.e., Section II adopts material specifications and individual Code sections approve their use), each Code section must approve the SWPS before they can be used. The Section I rules regarding the use of SWPS are found in PW-1.2, Responsibility. These rules allow the use of SWPS that have been accepted by Section IX provided the welding meets the requirements of Section I. Also, the manufacturer intending to use the SWPS shall describe in the Quality Control System (see Section I, Appendix A-302) the measures used to assure that the welding meets the requirements of both Section I and Section IX. (Also note that the National Board Inspection Code has approved the use of AWS standard welding procedures for repairs and alterations.)

WELDING DOCUMENTATION

Section IX provides suggested formats for Welding Procedure Specifications and Procedure Qualification Records (Forms QW-482 and QW-483 in Appendix B). These forms are not mandatory; any format that fits the needs of the manufacturer will do, so long as it furnishes the necessary information. In the case of the WPS,

paragraph QW-200.1(d) calls for the inclusion of, or reference to, all essential and nonessential variables. For a PQR, paragraph QW-200.2(d) requires a listing of all essential variables, the type and number of tests, and the results of the tests. The PQR includes a signed statement by the responsible manufacturer, certifying that the test welds were prepared, welded, and tested in accordance with the requirements of Section IX.

QW-301.4 requires the record of welder performance qualification tests, the WPQ, to list the essential variables, the type of test and test results, and the range of thicknesses and diameters for which the welder is qualified. Appendix B also provides a suggested format (Form QW-484) for a manufacturer to record the results of a welder's performance qualification test, or WPQ. This form also includes a signed certification by the manufacturer that the preparation, performance, and testing of the welds was done in accordance with the requirements of Section IX.

Section I has its own rules for welding qualification and weld record keeping, in PW-28. These rules essentially invoke all of the Section IX rules just described, but superimpose other rules having to do with maintenance of records of welding procedures and welders employed, showing the date, results of tests, and welding mark assigned to each welder. These records must be certified by the manufacturer and made available to the Authorized Inspector.

PW-28.4.1 requires that the manufacturer have a system that allows welded joints to be identified as to the welder or welding operator who made them. One way this can be accomplished is by having the welder stamp his or her mark on or adjacent to the welds. As an alternative, the manufacturer is permitted to maintain a record of welds and the welders used in making them. Section I has no requirement for maintaining those records after completion of the boiler, and the manufacturer is free to dispose of them at that time. Similarly, the welders' marks may soon be lost once the boiler is placed in service. This arrangement is quite reasonable since the identification of the weld with the welder who made it is most useful during construction. At that time, if a faulty weld were detected by NDE or hydrostatic test, other welds made by that same welder could be investigated. However, once the boiler has passed all required NDE and the hydrostatic test, the welds are presumably sound, and there is no longer much purpose to be served by retaining the records of which welder made any particular weld. This was affirmed by Interpretation I-92-78.

WELDING NONDUCTILE MATERIALS

As explained in the introduction, the ultimate goal of welding procedure and performance qualification is to achieve a weldment whose properties are at least the equivalent of the base material being joined. Usually, the WPS is proven to be capable of producing such a weldment by bend and tension tests of specimens cut from test coupons, which must show adequate strength and ductility. However, there are some nonpressure part materials (e.g., tube lug materials intended for high-temperature service in the boiler), which lack the ductility to pass a bend test. The important property for such materials is not ductility, but rather strength at elevated temperature, 1150°F (620°C) or higher. Typical alloys found suitable for such service often contain high percentages of chromium and nickel and lack the ductility required of pressure boundary materials.

In 1992, BPV I addressed this problem by permitting a test called a macro-examination instead of the usual mechanical tests required for procedure and performance qualification of groove and fillet welds. As explained in PW-28.1.2(b), a weld test coupon representing a typical production configuration may be evaluated by using the macro-examination method. The weldable quality of the nonpressure part materials is verified by examining a single cross-section of the weld. Visual examination of the weld metal and the heat-affected zone of both the pressure part and nonpressure material must show complete fusion and freedom from cracks.

WELDING VARIABLES

In the development of a WPS, it is necessary to establish which variables of the welding process are so-called **essential variables** in the production of qualifying welds and those which are not (**nonessential variables**).

Another category of variable is a **supplemental essential variable**, which becomes an essential variable only if notch toughness testing is required by the referencing book section. Section VIII sometimes requires such testing for vessels in low-temperature service, where the possibility of brittle fracture is a concern. Because Section I vessels are usually quite warm when pressurized, Section I does not require notch toughness, or impact testing, and supplemental essential variables are not used in welding for Section I construction.

The categorization of welding variables differs somewhat, depending on the welding process used and whether the variable applies to procedure or performance qualification. An essential variable for a weld procedure is one which, if changed, would affect the properties of the weldment and thus require requalification of the procedure, i.e., additional testing and issuance of a new PQR to support the changed WPS. A non-essential variable for a weld procedure is one that can be changed without requiring requalification, although it would require a change in the WPS. Essential variables for weld procedures include such things as material thickness, P-Number (which refers to material category, see below), F-Number (which refers to filler metal alloy, see below), and the use or omission of preheat or postweld heat treatment. Examples of nonessential variables for procedure qualification are groove design, root spacing, method of back gouging or cleaning, change in electrode size, and the addition of other welding positions than any already qualified.

An essential variable for welder performance is one that would affect the ability of a welder to deposit sound weld metal. Examples of such variables are deletion of backing in single welded groove welds (because it is more difficult to weld without backing), a change from one filler metal F-Number to another, a change in deposited weld metal thickness beyond the range qualified, and the addition of other welding positions than any already qualified. Note that this latter variable is an essential one for performance, since welding in a new position, such as vertical instead of horizontal, could certainly affect the ability of the welder to deposit a sound weld.

Section IX has a great number of tables summarizing procedure and performance variables for all common welding processes.

P-NUMBERS, S-NUMBERS, F-NUMBERS, AND A-NUMBERS

P-Numbers

One important essential variable is, of course, the type of base material being welded. There are several hundred different materials permitted for Code construction by the various book sections. If every change in base material meant that weld procedure specifications and welder performance had to be requalified, the qualification of procedures and welders for all these materials would be an enormous task. To reduce this task to manageable proportions, the ASME has adopted a classification system in which material specifications are grouped into categories, based on similar characteristics such as composition, weldability, and mechanical properties. Each category is defined by a **P-Number**. Within the P-Number category are subcategories called **Group Numbers** for ferrous base metals that have specified impact requirements. Although Section I does not use Group Numbers in relation to impact testing, it does sometimes establish different postweld heat treatment requirements for the different Group Numbers within a given P-Number category.

A welding procedure that has been qualified for a particular base material may be used for any other base material with the same P-Number. On the other hand, if a base material has not been assigned a P-Number, it requires an individual procedure qualification. Similarly, a welder who has been qualified for a base metal of a particular P-Number may be qualified for quite a few other P-Number base materials (see QW-423).

A numerical listing of P-Numbers and Group Numbers can be found for all Section II materials, by specification number, in Table QW/QB-422 of Section IX. That table was reorganized and expanded into its present form in the 1994 Addenda. In addition to the P-Numbers, the new version lists certain useful information about each material: UNS number (a number that categorizes each material by its nominal composition), minimum specified tensile strength, chemical composition, and product form. The previous version of Table QW/QB-422 was organized differently; it listed all P-Numbers by category: first, all the materials that were P-Number 1, then all the P-Number 3 materials, and so on. (There is no longer a P-Number 2 category; it

used to cover wrought iron, such as was used in some staybolts.) Under the old system, unless a user knew the P-Number of a given material, he or she had to search all the categories to find it. However, many users did like certain aspects of the old system, and in keeping with a tradition of placing certain superseded material in an appendix where it would remain available, Subcommittee IX put a material listing in the old format in Nonmandatory Appendix D. That arrangement groups materials by P-Number and permits a user to locate material specifications with matching P-Numbers more easily.

Although a specific definition of each P-Number in terms of chemical composition is not given in the Code, the P-Number categories for commonly used Section I materials are as follows:

- P-No. 1 covers plain carbon steels, C-Mn-Si, C-Mn, and C-Si steels.
- P-No. 3 covers low alloy steels obtained by additions of up to 0.75% of Mn, Ni, Mo, or Cr, or combinations of these elements.
- P-No. 4 alloys have higher additions of Cr or Mo or some Ni.
- P-No. 5 covers a broad range of alloys varying from 2¼Cr-1Mo to 9Cr-1Mo. This category is divided into two groupings, 5A and 5B. The 5A grouping covers alloys up to 3% Cr and 5B covers alloys with from 3% to 9% Cr.
- P-No. 15E (former P-No. 5B, Group 2) covers alloys having 9Cr, 1Mo and V.
- P-No. 8 covers the austenitic stainless steels.

S-Numbers

There is another material categorizing system that, until 2008, Section IX used for materials which were not included in the material specifications listed in Section II. As explained in QW-420 of Section IX, these were materials that were permitted for use by the ASME B31 Code for Pressure Piping and by certain Code Cases. These materials were grouped into **S-Number** groupings similar to the P-Number groupings and were listed with them in Table QW/QB-422 of Section IX. In 2008, the S-Numbers were reassigned the corresponding P-Numbers or P-Number and Group Number.

Base metals that have not been assigned a P-Number require individual procedure qualification.

F-Numbers

To reduce the number of weld procedure and performance qualifications, Section IX also categorizes welding filler metals (electrode, bare wire, cored wire, etc.) based on their usability characteristics, which determine the ability of welders to make satisfactory welds. These filler metals are listed in Table QW-432 of Section IX, which groups the various ASME filler metal specifications (SFA specifications) into **F-Numbers**. Part C of Section II lists American Welding Society filler metal specifications that have been adopted by the ASME and designated as SFA specifications.

Table QW-433 shows the extent to which performance qualification using one F-number qualifies a welder for other F-Numbers. Generally speaking, qualification with a filler metal that is more difficult to use qualifies a welder to use a filler metal that is easier to use.

A-Numbers

A last set of numbers called **A-Numbers** is designated in Table QW-442 for the classification of ferrous weld metal for procedure qualification. This table gives the chemical composition of the weld metal for the various A-Number groupings. Weld metal composition, i.e., A-Number, can be an essential variable for the WPS, but not for performance qualification.

The choice of welding electrodes and filler material for any given application is left to the judgment of the designer. It is often advantageous to match the weld metal composition with the base metal. Some general advice to this effect is found in PW-5.4:

Welding electrodes and filler metal shall be selected to provide deposited weld metal of chemical composition and mechanical properties compatible with the materials to be joined and the service conditions anticipated.

There is a pitfall to be avoided when selecting welding electrodes and filler metal for pressure retaining welds in 2¼ Cr-1Mo materials for service at design temperatures exceeding 850°F (455°C). In the late 1980s, after the occurrence of some piping failures, BPV I was advised to add a new requirement (PW-5.6), namely, that the weld metal must have a carbon content greater than 0.05% except for circumferential butt welds no larger than 3½ in. (89 mm) in outside diameter. That minimum carbon content is thought to be needed to maintain the elevated temperature strength of the weld metal. Interpretation I-92-41 reiterates the details of this requirement.

WELDABILITY

Materials are said to have good weldability if they can be successfully joined, if cracking resulting from the welding process can be avoided, and if welds with approximately the same mechanical properties as the base material can be achieved.

PW-5.2 prohibits welding or thermal cutting of carbon or alloy steel with a carbon content of over 0.35%. Higher carbon can cause zones of high hardness that impart adverse properties to the weld and heat-affected zone (HAZ) and may increase susceptibility to cracking because regions of high hardness often lack ductility. In fact, carbon strongly affects weldability due to its influence on hardenability during heat treatment. Heat treatment includes not only deliberate heat treatment such as solution annealing, it also includes the thermal cycle that the weld and HAZ undergo in the welding process.

Various empirical expressions, known as carbon equivalency (CE) formulas, have been developed to predict steel's hardenability by heat treatment. Thus, they have also proven to be rough indicators of the relative weldability of steels, their susceptibility to cracking during welding, and the need for preheat to prevent cracking during or after welding. This type of cracking is variously described as cold cracking, hydrogen cracking, and delayed cracking (because it may occur some hours after welding is completed). One common representation of a carbon equivalency formula used to determine whether steel needs preheat or postweld heat treatment to avoid cracking is given in AWS D1.1, Annex I (and used in Table PW-39, P-No. 1):

$$CE = C + \frac{(Mn + Si)}{6} + \frac{(Cr + Mo + V)}{5} + \frac{(Ni + Cu)}{15}$$

Thus, carbon equivalency (CE) is the sum of weighted alloy contents, where the concentration of alloying elements is given in weight percent. From this equation, it is seen that carbon is indeed the most potent element affecting weldability. The equation also shows the relative influence of other elements that might be present in pressure vessel steels, compared to that of carbon. Note that some elements such as molybdenum and vanadium actually contribute to weldability, at least in this particular carbon equivalency formula.

Associated with the various carbon equivalency formulas are weldability guidelines. A certain value of carbon equivalency, perhaps 0.35% or less, might indicate good weldability; a higher value might indicate that preheat and/or postweld heat treatment are required to avoid excessive hardness and potential cracking in the welds; and a still higher value might mean that the material is very difficult to weld and both high preheat and postweld heat treatment will be needed to obtain satisfactory welds. Another, slightly different example of a carbon equivalency formula is given in the supplementary (nonmandatory) requirements of ASME Specifications SA-105 and SA-106. For SA-105 forgings, the carbon equivalent is limited to 0.47 or 0.48, depending on thickness; for SA-106 pipe, the limit is 0.50. There would be little likelihood of making successful welds in these materials with CE values higher than those limits, even with high preheat.

Although various carbon equivalency formulas have been developed over the years for specific alloys, no universal formula has been devised that works well for all the low alloy steels. In fact, the more complex the alloy becomes, the more difficult it is to devise an equivalency formula. More recent formulas for low alloy steels involve more complex interactive terms rather than the simple additive terms of the formula cited above.

DESIGN OF WELDED JOINTS

The design of welded joints is covered briefly in PW-9, which says that they “shall preferably be of the double-welded butt type, but may also be of the single-welded butt type with the filler metal added from one side only when made to the equivalent of the double-welded butt joint by providing means for accomplishing complete penetration.” PW-9 then gives requirements for a tapered transition in joints between plate materials of different thickness, as discussed in the next section. Figure PW-9.1 illustrates what is intended.

For longitudinal shell joints, which are the most important because they are the most highly stressed, it is necessary to line up the center lines of the adjoining plates within the alignment tolerances permitted in Table PW-33. If these plates are not in such alignment, the membrane pressure forces carried by each shell plate would be offset from each other, creating a circumferential bending moment at the weld joint. This would be a source of additional stress in the shell. For circumferential shell joints, the centerlines of the plates are not required to line up because the membrane force in the axial direction is less than half of that in the circumferential direction, so the bending moment induced by the offset is much reduced, and there is also margin to sustain extra stress in the axial direction. Long experience has shown that this is a satisfactory design approach.

In the mid-1990s, a boiler manufacturer built a boiler drum in which the inside surfaces of the shell plates, instead of their centerlines, were lined up at the longitudinal weld joint. The boiler was in service by the time the error was discovered. The drum clearly did not conform to the rules of Section I. The manufacturer undertook some careful finite element analysis of the drum and evaluated the results using the design-by-analysis methods of Section VIII, Division 2. The analysis included the thermal stresses caused by start-up and shutdown of the boiler and a fatigue analysis of the combined pressure and thermal stresses. The manufacturer presented the results of the analysis to BPV I and asked for a Code Case permitting construction of a boiler drum without lining up the centerlines of the shell plate at the longitudinal weld joint. The manufacturer pointed out that Section VIII permits such construction and that the drum in question could have satisfied the design rules of Section VIII. After careful review and consideration, BPV I approved the case, Case 2210. It permits the inside surfaces of the shell plates to line up, under fairly restrictive conditions with respect to configuration thickness and pressure allowed. Once the case was approved, the longitudinal weld configuration used by the manufacturer became permissible, and the jurisdiction where the boiler was installed granted the owner a continued operating permit for the boiler, which is now considered a so-called state special. The Code Case was eventually incorporated into Section I in the 2001 Edition. The alternate alignment rules are now found in PW-9.3.1 and PW-9.3.2.

BENDING STRESS ON WELDS

As explained in the chapter on the determination of allowable stresses, most of the design formulas in both Sections I and VIII are based on the use of membrane stress as the basis for design. In a boiler, the tubes, the piping, the headers, and the shell of the drum are all designed for the membrane stress in their cylindrical walls. Bending stress and the effects of stress concentration are not calculated, although they are known to be present to some extent. This is explained, not in Section I, but in UG-23(c) of Section VIII. In fact, there are

bending stresses in such pressure vessel components as flat heads, stayed heads, dished heads, hemispherical heads, and cylinder-to-cylinder junctions.

In recognition of the existence of these largely unavoidable bending stresses, and perhaps still reflecting some lack of confidence in the soundness of welded construction, Section I contains a number of design rules intended to minimize bending stresses on welded joints. For instance, except as provided in PW-9.3.2 (see discussion of Case 2210, above), PW-9.3 requires a gradual taper of no greater than 3:1 between plates of unequal thickness. PW-9.3 also advises that its rules for transition slopes do not apply to joint designs specifically provided for elsewhere in Section I. Less restrictive rules are provided for counterbored weld end transitions where components such as valves and pipes or fittings are welded together. (See Fig. PG-42.1 of Section I.) For such applications, a maximum slope of 30 deg. is permitted.

Long after these rules were formulated, finite element analyses have demonstrated their validity. That is, the discontinuity stresses developed at these gradual changes in thickness have generally been found to be unremarkable and well within the limits that would apply if the design-by-analysis methods of Section VIII, Division 2 were to be applied.

For decades, paragraph PW-9.4 had prohibited construction in which bending stresses were “brought directly on a welded joint.” This paragraph had also specifically prohibited a single-welded butt joint subject to bending stress at the root of the weld, as illustrated in Fig. PW-9.2. In 1996, BPV I recognized that bending stresses routinely occur on welded joints in all boilers and pressure vessels with no untoward results and that this broad prohibition against bending stresses was unwarranted. Accordingly, PW-9.4 was revised in the 1997 Addenda. The general prohibition against subjecting weld joints to bending stress was deleted, and PW-9.4 now prohibits only the single-welded corner joints illustrated in Fig. PW-9.4.

ACCEPTANCE CRITERIA FOR WELDS

Part PW includes fabrication rules covering welding processes, base metal preparation, assembly, alignment tolerances, and the amount of excess weld that may be left on the weld joint (so-called reinforcement). In general, butt welds in pressure-containing parts must have complete penetration, and the weld groove must be completely filled. To assure that it is and that the surface of the weld metal is not below the surface of the adjoining base metal, extra weld metal may be added as *reinforcement* on each face of the weld. A table in PW-35 gives the maximum amount of reinforcement permitted, as a function of nominal thickness and whether the weld is circumferential or longitudinal. Requirements for butt welds are found in PW-9, PW-35, and PW-41.2.2. PW-9, and PW-35 stipulate that butt welds must have full penetration. PW-41.2.2 adds that complete penetration at the root is required for single-welded butt joints and that this is to be demonstrated by the qualification of the weld procedure. Lack of penetration is a reason for rejection of welds requiring radiography. PW-35.1 limits undercuts to the lesser of $\frac{1}{32}$ in. (0.8 mm) or 10% of the wall thickness, and the undercut may not encroach on the required wall thickness. As explained in PW-41.2.2, some concavity in the weld metal is permitted at the root of a single-welded butt joint if it does not exceed the lesser of $\frac{3}{32}$ in. (2.5 mm) or 20% of the thinner of the two sections being joined. When concavity is permitted, its contour must be smooth, and the resulting thickness of the weld, including any reinforcement on the outside, must not be less than the required thickness of the thinner section being joined.

It is generally not possible to measure concavity directly, and in 1983, an inquiry was received by BPV I (resulting in Interpretation I-83-36) asking the following question:

Question: When concavity at the root of a weld is shown by radiography, can the actual depth of $\frac{3}{32}$ in. or 20% of the thinner section being joined be measured by radiographic density only?

Reply: Section I does not address measurement of concavity.

Question: Is concavity at the root of a weld as determined by radiography acceptable if the contour of the concavity is smooth and the density change is not abrupt?

Reply: *One of the criteria for acceptability of concavity is that the contour be smooth. PW-41.2.2 contains several additional criteria.*

A 1992 Interpretation, I-92-75, dealt with the complete penetration of butt welds in boiler tubes and how it may be demonstrated:

Question: *Is it a requirement of Section I that all boiler tube butt welded joints be complete joint penetration welds?*

Reply: *Yes.*

Question: *When radiography is not required, and visual examination of the root is not practical, what demonstration in addition to the requirement of PW-41.2.2 and a successful hydrostatic test is necessary to accept circumferential butt welds covered by PW-41?*

Reply: *None.*

Question: *Is it a requirement of Section I that the manufacturer be responsible for meeting the applicable requirements of Section I?*

Reply: *Yes. The manufacturer is responsible for meeting the requirements of Section I and of his Quality Control Program.*

When BPV I replied that Section I does not address the measurement of concavity, it was tacitly acknowledging the difficulty of making such measurements. This reply also reflects the industry's good experience with single-welded circumferential butt joints in boiler and superheater tubes using all of the above-described acceptance criteria. Some part of this success is also due to the fact that the axial stress in these tubes at the butt joints is generally less than half of the allowable design stress, as explained in Radiographic Examination of Welds at the end of this chapter.

TUBE-TO-HEADER ATTACHMENT USING PARTIAL PENETRATION WELDS

A review of the acceptable types of nozzles and other connections illustrated in Fig. PW-16.1 shows a number connected by partial penetration groove welds. One very widely used detail for tube-to-header connections is shown in Fig. PW-16.1(z). The application of this detail confuses some designers, and over the years, BPV I has answered several inquiries about its use. As can be seen in the side view (section 1-1) of the connection, the following requirements are imposed (all nomenclature is defined in PW-16.2):

1. There must be a groove weld whose depth, t_w , is equal to the wall thickness, t_n , of the attached tube or nozzle, but not less than $\frac{1}{4}$ in. (6 mm)
2. A fillet weld with a throat equal to t_c must be provided on top of the groove weld.
3. The tube must project below the bottom of the groove weld at least $\frac{1}{16}$ in. (1.5 mm). The sketch shows a recess of that depth, but by Interpretation I-92-95, BPV I explained that the tube need not rest on such a shoulder and that a through-hole in the header matching the outside diameter of the tube was permissible so long as the tube extended into the hole a minimum of $\frac{1}{16}$ in. (1.5 mm) beyond the machined weld groove. (The purpose of a recess or insertion into a hole matching the OD of the tube is to ensure that the tube is centered properly, so that adequate weld is provided all around the tube.)

From the two views of PW-16.1(z), it can be seen that adequate header thickness is needed to provide for the depth of the groove weld and that beyond some maximum ratio of tube diameter to header diameter, the above requirements cannot be met. This is because the groove weld would have little or no depth on the hillside portion of the header, as is shown in the left sketch of PW-16.1(z). Advice to this effect is given in two hard-to-find interpretations. Although they were issued in 1977 and 1978, one appeared on page 161 in Volume 5 of the interpretations as part of errata to Volume No. 3 of the Interpretations, with no title, but

under the heading Section I, Weld Joint Acceptability Under Figure PW-16.1. The other appeared in 1984 as Interpretation I-83-08R, on page 61 of Volume 15 of the interpretations.

ALIGNMENT TOLERANCE

PW-33 addresses the alignment tolerances that apply when plates are butt welded together. These tolerances are expressed as the amount of offset permitted at the edges of the plates. Table PW-33 lists these tolerances for longitudinal and circumferential welds as a function of the thickness of the plates to be joined. Any offset within the allowable tolerance must be faired at a 3 to 1 taper across the width of the finished weld. The addition of weld metal beyond what otherwise might be the edge of the weld may be needed in order to achieve the 3 to 1 taper.

In 1995, a dispute arose regarding the alignment tolerance required when tubes are butt welded end to end. As explained in Radiographic Examination of Welds at the end of this chapter, these circumferential tube joints do not require radiography, and there are accordingly no acceptance standards to guide the parties. The inquirer wanted to know whether the alignment tolerances of PW-33 for plates applied to circumferential joints in tubes. In Interpretation I-95-01, BPV I replied that they do not. That left the question of just what tolerances do apply to such joints. The committee considered the problem and decided to revise the title of PW-33 so that it would cover alignment tolerance for shells and vessels, including pipe or tube when used as a shell. At the same time, a new paragraph, PW-34, was added to cover alignment when tubes or pipe are butt welded end to end. That paragraph specifies only that the alignment shall provide for complete weld penetration at the inside surfaces.

BACKING RINGS

PW-41.2.2, in discussing single-welded butt joints, stipulates that if complete penetration at the root cannot otherwise be assured, the procedure shall include a backing ring or equivalent. Occasionally, a dispute arises as to what material may be used for a backing ring. The answer to this question is found in PW-41.2.4, which says only that material for backing rings shall be compatible with the weld metal and the base material and shall not cause harmful alloying or contamination. Thus, the manufacturer is free to use its best judgment in choosing any material that meets those criteria. Backing rings may be left in place or removed as desired.

PREHEATING

Deposited weld metal is cooled very quickly by its surroundings. Once it solidifies, it forms various microstructural phases — solid solutions of iron and carbon (and other alloying elements). These phases include ferrite, pearlite, bainite, martensite, and austenite (in the higher alloy materials). The formation of any particular phase depends on the cooling rate and alloying elements, such as chromium or nickel, which may be present. Certain phases, e.g., untempered martensite or bainite, can impart unfavorable properties to the resulting weldment (high hardness, lack of ductility, lack of fracture toughness). One way to address this problem is through the use of preheating, which, by raising the temperature of the surrounding base metal, slows the cooling of the weld and may prevent the formation of undesirable phases.

Preheat serves another useful function. It assures that the weld joint is free of any moisture, which can otherwise serve as a source of hydrogen contamination in the weld. Hydrogen can dissolve in liquid weld metal and by various mechanisms cause cracking in the weld (known variously as cold cracking, hydrogen-assisted cracking, and delayed cracking). Maintaining the weldment at preheat temperature during and after welding

promotes the evolution of dissolved hydrogen. Although preheating a weld joint can be beneficial, Section I does not mandate the use of preheat except as a condition for the omission of postweld heat treatment (as provided in Table PW-39). However, it is often specified for new construction welding and for repair welding, especially when the walls are relatively thick. A brief guide to preheating practices is included in Non-mandatory Appendix A-100.

It is important to remember that while Section I does not normally mandate preheat, B31.1, Power Piping, does. Consequently, all welds (including tack welds) in boiler external piping require preheat. The preheat temperatures required for the various P-Number materials are given in B31.1, paragraph 131, which also specifies the size of the region around the weld that must be maintained at the preheat temperature. These preheat requirements are similar to those in Nonmandatory Appendix A-100 of Section I. It turns out that for many commonly used carbon and low alloy steels up to 2-in. thick, the preheat temperature is only 50°F. Note also that the B31.1 definition of thickness for consideration of preheats is the *greater* of the nominal thicknesses at the weld for the parts to be joined. This is different from the B31.1 definition (in paragraph 132.4) of nominal thickness to use when considering PWHT requirements. Unfortunately, the Section I definition of nominal thickness (in PW-39.3) for consideration of PWHT requirements differs from that of B31.1. This is discussed further in the next section.

POSTWELD HEAT TREATMENT

As explained under preheating, rapidly cooling weld metal and the adjacent heat-affected zone are subject to the formation of adverse phases, which can result in zones of high hardness, lack of ductility, and poor fracture toughness in the weldment. In addition, the differential cooling of the weld metal compared to the surrounding base metal can lead to the formation of very high residual stresses. Again, the extent to which any of these effects takes place is a function of the cooling rate, alloy composition, relative thickness of the parts being joined, and whether preheat is applied. Experience has shown that preheat and postweld heat treatment (PWHT) are often unnecessary for relatively thin weldments, especially those of plain carbon steel. However, the general rule of PW-39 is that all welded pressure parts of power boilers shall be given a postweld heat treatment unless otherwise specifically exempted (e.g., by PEB-9 or PMB-9) or exempted by the notes in Table PW-39. The materials in Table PW-39 are listed in accordance with the P-Number grouping of QW-422 of Section IX.

There are some materials for which PWHT is neither required nor prohibited. These are the P-No. 8 (austenitic stainless alloys), P-No. 10H Group 1 (ferritic stainless alloys), P-No. 31 (copper and copper-based alloys), P-No. 45 (nickel and nickel-based alloys), and P-No. 51 (titanium alloys). There is also one material group, P-No. 10I Group No. 1 (ferritic stainless alloys) for which PWHT is always required.

While preheat is aimed at preventing or limiting the formation of adverse phases, postweld heat treatment is used to ameliorate their effects. Postweld heat treatment is capable of tempering, or softening, hard phases and it can restore a large measure of ductility and fracture toughness in the weld and heat-affected zone. At the same time, it relieves most of the residual stress caused by the cooling of the weld metal. The goal of PWHT, therefore, is to restore the properties of the weldment as nearly as possible to those of the original base metal.

Exemptions from PWHT

The exemptions from PWHT permitted by the tables in PW-39 are listed for various types of welds: circumferential welds in pipes, tubes, or headers; fillet welds attaching pressure parts such as socket welding fittings; fillet welds attaching connections to vessels; fillet welds attaching nonpressure parts to pressure parts; and seal welds on tubes, closures, or fittings secured by mechanical means such as rolling or threading. For each type of weld, exemptions from PWHT may be available if certain limits are

not exceeded. The limits are based on such parameters as material thickness, carbon content, chromium content, fillet weld throat size, component diameter, opening diameter, or a requirement for preheat at a particular temperature. One common misunderstanding regarding PWHT exemptions is what Section I means by the term **circumferential welds**. This term applies only when the two parts such as two tubes, or two pipes, or two sections of a cylindrical shell are butt welded end to end. The weld between a tube stub and a header, or the weld between a handhole or manhole frame and a drum, is not considered a circumferential weld and therefore must be given a PWHT unless a specific exemption can be found that covers the situation. (This was affirmed by Interpretations I-92-23 and I-92-77.) The rationale behind this definition of a circumferential weld is that the abutting parts are likely to have comparable thickness and one would not be a significantly greater heat sink than the other, so that there need be no concern about rapid cooling of the weld that would potentially leave it with undesirable characteristics for which PWHT would be advisable.

Sometimes, manufacturers of firetube boilers stop construction just short of completion and place the boilers in stock, in anticipation of orders. Occasionally, a purchaser wants a nozzle added to a boiler as an auxiliary steam connection or to provide for a larger size safety valve, and the addition of such a nozzle would normally require PWHT. PWHT can damage a firetube boiler with rolled tubes because rolled joints loosen at PWHT temperatures. (Rolled tubes are held in place by residual stresses deliberately induced in the tubes and the tubesheet by an expanding process, and at PWHT temperatures, these stresses relax.) The problem of adding nozzles to a boiler without either repeating PWHT or doing a local PWHT was brought to BPV I. After due consideration, the committee developed Code Case 1918, Attachment of Nozzles or Couplings to a Boiler Vessel After PWHT. This case allows the attachment of not more than two nozzles or couplings subject to quite a number of restrictions intended to ensure that PWHT can be safely omitted. The nozzle must be made of P-No. 1 Group 1 or 2 material, its size is limited to NPS 4 (DN 100) with a maximum wall thickness of ½ in. (13 mm), vessel thickness is limited to ¾ in. (19 mm), only certain weld configurations of PW-16 are permitted, and a minimum preheat of 200°F (111°C) must be applied. Despite these many restrictions, the case can be very useful if some small connection needs to be added to a boiler vessel after the PWHT has been completed. Moreover, the case applies to all boilers, not just firetube boilers. In the early 1990s, a proposal to incorporate Case 1918 into Section I was not approved, and it is expected to be among those few that remain in effect indefinitely.

In PWHT, the components to be treated are placed in a heat treatment furnace and slowly heated to the temperature specified in Table PW-39. They are held at that temperature for the time specified, usually 1 hr/in. of thickness up to a certain thickness plus 15 min additional for every inch above that thickness. This rule is intended to ensure that the centermost portions of thick sections have sufficient time to reach the minimum holding temperature. The nominal thickness in Table PW-39 used to determine PWHT requirements is the thickness of the weld, the pressure retaining material, or the thinner of the sections being joined, whichever is the least. The time at temperature requirement can be satisfied by an accumulation of postweld heat treatment cycles. When it is impractical to heat treat at the specified temperature, it is permissible to do the heat treatment at lower temperatures for longer periods of time, but only for P-No. 1 and P-No. 3 materials. Table PW-39.1 lists these alternative longer times. The table shows that for a 50°F (28°C) decrease in the minimum specified holding temperature, the holding time doubles. This shows how strongly temperature-dependent the underlying creep relaxation process is.

Unlike some other book sections, Section I usually does not specify any particular heating or cooling rate to be used in PWHT. PW-39.3 stipulates only that the weldment shall be heated slowly to the required holding temperature. It goes on to say that after being held at that temperature for the specified time, the weldment shall be allowed to cool slowly in a still atmosphere to a temperature of 800°F (425°C) or less. This is to avoid high thermal stresses and potential distortion caused by large differential temperatures throughout the component. Table PW-39 does have two groups of material for which it gives advice on the cooling rates to be used following PWHT. Those are the P-No. 7 and the P-No. 10I materials. Notes in the PW-39 tables applicable to those materials specify a maximum cooling rate of 100°F/hr (55°C/hr) in the range above 1200°F (650°C), after which the cooling rate “shall be sufficiently rapid to avoid embrittlement.” In some cases,

this might be 400°F/hr (205°C/hr). Presumably, the manufacturer has sufficient knowledge of metallurgy to determine how rapid that rate must be.

Local Postweld Heat Treatment

Local postweld heat treatment is permitted as an alternative to heating a complete assembly. It is also used following repair welding, when the complete assembly may have already received its PWHT and repeating the whole process would be unnecessary and uneconomical. PW-39 requires that local PWHT be accomplished by heating a circumferential band around the vessel to the prescribed holding temperature. The minimum width of the band is three times the plate thickness on either side of the welded joint. If a nozzle or other attachment is being given a local PWHT, the circumferential band must extend on either side of the nozzle by at least three times the wall thickness. PW-39.6 provides similar circumferential band rules for local PWHT of welded joints in pipes, tubes, and headers.

The basis of the heated circumferential band method is this: The welds and heat-affected zone must be brought up to the prescribed temperature and held there, and the band widths specified are simply a means of assuring that this happens. To avoid creating high thermal stresses that might undo some of the benefits of the PWHT, it is necessary that the entire circumference be brought up to a uniform temperature. This can be seen by considering the temperature distribution in the vessel. For example, the prescribed PWHT temperature for a P-No. 1 material is 1100°F (595°C). If the rules for local PWHT are followed, the resulting temperature distribution consists of a band at 1100°F (595°C), with the temperature decreasing along the vessel in either direction away from the band. The axial plot of temperature would look fairly symmetrical, with a flat top at the 1100°F (595°C) band and axial temperature gradients sloping down to cooler portions of the vessel on either side. With such a temperature distribution, the heated band is permitted relatively free and uniform thermal expansion, thereby avoiding high thermal stresses.

By contrast, consider what might happen if a local PWHT were attempted on a nozzle at the middle of a dished head by heating only the nozzle and a narrow region of the head surrounding it. The heated portion is constrained from expanding by the much cooler surrounding portion of the head. Thermal stresses exceeding the yield strength of the material might occur, leaving the vessel with high residual stresses after it cools. This may be more readily appreciated by considering a simpler but analogous problem, that of a large flat plate with a small circular hot zone in the middle of the plate. The hot circular zone is constrained from expanding by the surrounding cooler material, and thermal stresses greater than yield may easily develop, leaving high residual stresses after the plate cools. Since one of the goals of PWHT is to mitigate residual stresses, Section I always requires heating a band all the way around the vessel. Paragraph PW-39.5 does, however, provide rules that allow some variation in the circumferential heat band width and temperature. It also provides rules for local post weld heat treatment of nozzles and welded attachments in spherical shells heads and nozzles that contain circumferential welds close to the vessel or shell. In general, the rules stress control of temperature gradients that may be harmful to the vessel.

Minor Repairs After PWHT

Occasionally, some minor local damage is done to completed boiler components after postweld heat treatment, and a little repair welding is needed. Unless an exemption from PWHT is available in PW-39, the PWHT would have to be repeated for the whole component. In the late 1970s, BPV I granted some relief from this problem when the welding was considered so minor that any further postweld heat treatment could reasonably be waived. New provisions were added to PW-40.2 covering tube-to-header or tube-to-drum welded joints that have already received their required PWHT. In such cases, minor local additional welding for certain listed materials without repeating the PWHT became permissible, subject to limitations on tube size, depth of reworked weld, use of preheat, and qualification of the welding procedure for the thickness

of rework welding to be performed without PWHT. This approach is analogous to that of PW-54.3, which permits the welding of nonpressure parts to pressure parts after the hydrostatic test (see discussion under Hydrostatic Testing).

Interpretations on PWHT

There have been a number of interpretations on the subject of PWHT. Several are worthy of mention. One was Interpretation I-80-10, which dealt principally with local PWHT. Several questions were posed. One was whether a gas torch could be used to perform the PWHT. BPV I replied that Section I did not restrict the method of heating; a gas torch was an acceptable method. Another question was whether temperature-indicating crayons could be used to indicate postweld heat treatment temperatures. The reply was that Section I did not restrict the method of temperature indication, provided the method selected permitted control of PWHT within Section I limits for the material involved.

Another inquiry on PWHT asked whether there was a *maximum holding temperature* for PWHT. BPV I replied in Interpretation I-81-04 that Section I did not define such a limit. (This was slightly inaccurate, since Table PW-39 did at that time stipulate a maximum holding temperature of 1175°F (635°C) for SA-203, a P-No. 9B, low nickel alloy sometimes used for pressure vessel plates.) At this writing, Section I sets the maximum holding temperature for P-No. 15E materials at 1425°F (775°C). Within certain Ni + Mn chemistry limitations, the maximum holding temperatures may be increased to either 1450°F (790°C) or 1470°F (800°C). It is critical that the upper limit of 1470°F (800°C) not be exceeded because the remedial actions required vary from replacing the weld to replacing portions of the component.

It happens that B31.1, Power Piping, does not list just a single minimum PWHT holding temperature. It lists a temperature range, and advises that the upper limit of the range may be exceeded, provided the actual temperature does not exceed the lower critical temperature of any of the materials (at which point some undesirable metallurgical change might occur). Power Piping also provides Table 129.3.2, which gives approximate lower critical temperatures for various commonly used piping materials. A note under the table indicates that the information is for guidance only and that the user may use other values obtained for specific materials.

TEST PLATES

One of the last subjects covered in Part PW is that of test plates for vessel welds. This subject dates back to at least the 1933 Edition of Section I and is covered in considerable detail in PW-53. The purpose of the rules is to assure that the weld joints have at least the same tensile strength as the base material. Most of this text had changed very little until, in 1964, a clause was added to PW-53.1 that exempts cylindrical pressure parts constructed of P-No. 1 materials from these test requirements. Since most boiler drums are made of these plain carbon steel materials, the tests are not required. In fact, most of this testing duplicates the testing already covered by the material specifications and the weld procedure qualification. Moreover, 30 years of experience have shown that the testing called for by the material specifications is sufficient for the materials ordinarily used for pressure vessels. With this in mind, it would be reasonable to think that the rules in PW-53 are no longer warranted and that the paragraph should be deleted. This was suggested in 2001, but a number of manufacturers provided convincing arguments for retaining the rules. These arguments centered on the growing use of non-North American manufacturers, particularly those in developing countries. One manufacturer recalled testing weld filler material to be used to make a production weld. The material failed well below the required tensile strength. Such material would not have been detected if the test plate requirements of PW-53 were removed. The action to delete PW-53 was not pursued by BPV I. Last revised in the 2003 Addenda, PW-53 now provides rules for using small size all-weld-metal tension specimen for tests.

INTERPRETATIONS ON WELDING

PW-28 makes it clear that welding of pressure parts to each other, and the welding of load-carrying non-pressure parts to pressure parts, requires the use of qualified welders using qualified procedures. However, when the welding process is automatic, welding procedure and performance qualification is not required for attachments such as fins that have essentially no load-carrying function. A number of questions about the welding of fins have been considered by BPV I.

One fin question was considered under Interpretation I-81-18. The question was whether and under what conditions a boiler manufacturer could buy tubes with machine resistance welded fins from an outside organization (presumably one without a Code symbol stamp) and use the tubes for Section I construction. This inquiry was answered in 1981 as follows:

Reply: Tubing with machine resistance welded fins falls in the category of miscellaneous parts and the rules of PG-11 apply, including requirements for marking and inspection.

Such fins are usually considered to “have essentially no load-carrying function” (see PW-28.1.2). In 1981 PW-28 permitted such fins to be joined to pressure parts by any machine welding process performed in accordance with a welding procedure specification, without requiring procedure and performance qualification testing. The rules were changed around 1990 so that procedure and performance qualification testing is required for all types of welding except automatic welding (in which the equipment performs the welding without adjustment of the controls by the welding operator). However, under either the old rules or the later rules, finned tubes could be furnished as standard welded pressure parts under the provisions of PG-11.3, which call for the parts manufacturer to do any welding in accordance with virtually all the requirements of Sections I and IX. As explained in Chapter 11 under Standard Pressure Parts, the parts manufacturer need not have a Code symbol stamp to provide welded parts.

The calibration of welding equipment is not mentioned in the Code. In 1983, an inquiry on this subject was received that applied to Sections I, IV, and VIII. It was answered in Interpretation I-83-45:

Question: Is it a requirement of Section I, IV, VIII, Divisions 1 and 2, that manual, semiautomatic, and automatic welding equipment be calibrated, and if so, that the devices used for calibration be calibrated?

Reply: No.

In considering the calibration question, the various committees apparently agreed that the industry has developed welding methods and equipment that provide satisfactory welds when the procedures and welders are qualified in accordance with Code rules. The Code also mandates NDE for the welds (visual, radiographic, or ultrasonic examination), which is intended to detect significant imperfections, whatever their cause.

PW-31 deals with the assembly of parts to be welded. It mentions tack welding as a means of holding the edges of parts to be welded in alignment. Tack welds must be made using a fillet weld or butt weld procedure qualified in accordance with Section IX. Once they have served their purpose, tack welds may either be removed completely or then starting and stopping ends have to be prepared by grinding so that they can be satisfactorily incorporated into the final weld. Tack welds to remain in place must be made by qualified welders and examined visually for defects and, if found defective, must be removed.

Often, a manufacturer authorized to use a Code stamp subcontracts the rolling of a shell to an outside organization, one without an ASME Certificate of Authorization to use a Code stamp. The question then arises as to whether and under what circumstances the subcontractor may use tack welding. This question was answered in 1983 for Sections I, IV and VIII, Division 1, by Interpretation I-83-46, as follows:

Question: A manufacturer, holder of a valid U S, H, or M Certificate of Authorization, subcontracts an outside organization to roll a shell, which is to be part of a stamped boiler or vessel, and to perform tack welding to secure the longitudinal seam alignment. The outside organization is not part of the Certificate holder's organization. Under what conditions may this work be performed?

Reply: In accordance with paragraphs PW-31 of Section I, HW-810 of Section IV, and UW-31 of Section VIII, Division 1, tack welds, whether removed or left in place, shall be made using a fillet weld or butt weld procedure qualified to Section IX. Tack welds to be left in place shall be made by welders qualified to Section IX and shall be examined visually for defects, and if found to be defective, shall be removed. It is not necessary that a subcontractor performing such tack welds for the boiler or vessel manufacturer be a holder of an ASME Certificate of Authorization. The final boiler or vessel manufacturer shall maintain the controls to assure that the necessary welding procedure and performance qualifications are met in order to satisfy Code requirements.

Questions sometimes arise as to what extent pipe and tube made by electric resistance welding (ERW) must meet any of the Section I rules for welding and welded products. ERW pipe and tube are made by an automatic welding process under what are supposed to be carefully controlled factory conditions. Included in the manufacturing process are various nondestructive examination methods, whose purpose is to assure the soundness of the welds. These NDE methods may include eddy-current testing, ultrasonic testing, and hydrostatic testing. When ERW products were introduced years ago, there were occasional problems with faulty welds that escaped detection, and the Code committees imposed an arbitrary 15% penalty on the allowable stress for such products. More recently, following years of generally satisfactory experience, the penalty has been dropped for some tubular products when extra NDE is provided for the full length of the ERW seam. Nevertheless, some committee members lack full confidence in ERW tubing because of the possibility that NDE may not always be effective in weeding out bad welds, for one reason or other. There have been several interpretations on the subject, which have established that the weld in ERW products does not require PWHT or radiography by the boiler manufacturer and that ERW pipe may be used for the shell of an electric boiler built to the rules of Part PEB without inspection and Manufacturer's Partial Data Reports. These 1986 Interpretations are I-86-40, I-86-55, and I-86-56, as follows:

Question: When ERW pipe or tube which complies with a material specification is used as a nozzle, does PW-11 require that the longitudinal seam be radiographed?

Reply: No.

Question: When ERW pipe or tube which complies with a material specification is used as a nozzle does Table PW-39 require that the longitudinal seam be subjected to postweld heat treatment?

Reply: No. (Note: Remainder of reply omitted because it was on another subject.)

Question: May SA-178 Grade A ERW tubing produced by a supplier who is not a Code Certificate Holder be used as the shell of a boiler constructed to the rules of Part PEB?

Reply: Yes.

Note that in asking this last question, the inquirer was laboring under a misapprehension. The tube manufacturer is never required to have a Certificate of Authorization to use a Code symbol stamp, since the manufacturer is not engaging in Code construction when it manufactures tubing, even though that tubing is used in Code construction. The underlying question is simply whether ERW tubing may be used for the shell of an electric boiler; the answer is that it can be so used. This interpretation clarifies the application of footnote 6 to PG-11 on standard pressure parts. At that time the footnote said that fusion-welded pipe for use as the shell of a vessel is subject to the same requirements as a shell fabricated from plate, including inspection and Manufacturer's Partial Data Reports. However, ERW pipe is welded without the addition of filler metal, by a fully automatic process, and the welding and other aspects of pipe quality assurance are considered adequately controlled by the governing ASME material specification. Consequently, it was reasoned that the inspection referred to in footnote 6 (which would have consisted of assuring proper long seam welding, PWHT, and radiography) is not needed, and the piece of pipe can be treated as a standard pressure part that does not require inspection and a Manufacturer's Partial Data Report. In 1992, BPV I issued Interpretation I-92-82, essentially covering the same ground as I-86-56 (above), advising that ERW pipe material listed in PG-9.1 may be used as the shell of an electric boiler, subject to the PEB-5.2 minimum shell thickness

requirement of $\frac{3}{16}$ of an inch (5 mm). Footnote 6 to PG-11 was revised in the 2000 Addenda to clarify that fusion-welded pipe “with filler metal added” was subject to the same requirements as a shell fabricated from plate. (Of course, the rest of the boiler, including head-to-shell welds and nozzle-to-shell welds, require the full application of Section I rules; it is only the ERW seam that is exempt.)

PW-40 covers the repair of weld defects. It stipulates that imperfections detected visually, by leak tests or by the volumetric examinations mandated by PW-11 (RT or UT), must be removed. The weld joint must then be rewelded and reexamined. An interpretation, I-86-66, issued in 1988 relaxed the otherwise rather strict rules concerning who can make weld repairs on Section I components, as follows:

Question: May a non-Certificate Holder’s welders be used in his shop, provided that they are under the control and supervision of a Certificate Holder under the conditions and requirements of PW-1.2 and PG-105.3, to make repairs either on pressure parts in a new vessel or on new vessel parts which are to be stamped with the ASME Section I symbol?

Reply: Yes.

Another interpretation, I-95-29, was issued in 1996 that covered more than repairs. It reiterated, with further clarification in question and reply 1, Interpretation I-86-66 cited above.

Question 1: May a holder of an ASME Certificate of Authorization using their own qualified welding procedures, supervise the Code welding performed by welders qualified by a different organization, and assume Code responsibility, including stamping and certification, for that welding?

Reply 1: No.

Question 2: Provided all requirements of PW-1.2 are met, may a holder of an ASME Certificate of Authorization use services of individual welders employed by an organization not holding an ASME Certificate of Authorization?

Reply 2: Yes.

On hindsight, it can be argued that Code rules existing at the time did not support either of the interpretations and that they are examples of “Code rules by interpretation.” This appears to have been recognized by BPV I because in the 2000 Addenda, PW-1.2 was revised to permit a certificate holder to use the services of individual welders who are not in his employ provided certain conditions are met. These include using the certificate holder’s WPS and qualification of the welders by the certificate holder. Also, the certificate holder’s quality control system must include requirements for complete administrative and technical supervision by the certificate holder, authority to assign and remove welders, assignment of welder identification symbols, and acceptance of the system by the certificate holder’s Authorized Inspection Agency.

One design feature that was not, until the 1999 Addenda, explicitly covered by the rules of Section I is the attachment of nozzles by single fillet welds. There had been several interpretations on the subject: I-79-18, I-86-82, and I-92-86. The reply in all these cases was that Section I does not permit the attachment of small-diameter nozzles, or internally threaded fittings, or tubes to headers, by single fillet welds only. Where Section I did permit single fillet welds, additional mechanical support had to be provided by some other means, such as by expanding. In such situations, the weld was considered a seal weld, and the strength of the joint was attributed to the expansion of the tube. Several such combined attachment methods for tubes are described in PWT-11.1 and PFT-12.2.

In the early 1990s, BPV I attempted to include in PW-15 a specific prohibition against the attachment of nozzles and other connections by single fillet welds, but the action was blocked by some Committee members who considered properly designed fillet welds a satisfactory means of attachment and by others who noted that Section VIII permits the use of at least some single fillet welded connections. However, the members of BPV I continued to have a number of concerns about using such connections, among which are these: Section I is a system Code, covering the boiler and attached piping. Due to its thermal expansion, the piping often imposes mechanical loading on the boiler connections. In a single fillet welded connection, the fillet

welds would have to resist these external forces and moments in addition to their function of attaching the connection and transferring pressure loads. Moreover, it is not always possible to ensure full fusion at the root of a fillet weld and that root can be a weak point with respect to stress concentration and susceptibility to corrosion. Also, when Section VIII permits the use of single fillet attachment welds [see Fig. UW-16.1, UW-16.2, and UW-16(e) and (f)], several restrictions are imposed. Fittings attached to the outside of a vessel by single fillet welds are limited to a maximum size of NPS 3 (DN 80). Also, when a nozzle neck or tube is attached from the inside only, and there are external loads on the nozzle, the clearance permitted between the outside of the nozzle and the vessel wall is restricted [see Fig. UW-16.1 (v) and (w)]. Thus, the vessel wall could help resist any significant bending moment on the nozzle, thereby limiting the loads transmitted to the single fillet weld.

The design rules of Section VIII seemed reasonable, and those supporting the adoption of similar rules by Section I continued their efforts toward that end. Rules allowing attachment of necks and tubes with a single fillet weld were issued in the 1999 Addenda. The rules restrict the fillet to the inside of the vessel. The rules found in PW-16.6 now allow necks and tubes not exceeding NPS 6 (DN 150) to be attached with partial penetration or fillet welds from one side only on either the outside or inside of the vessel or shell. If attached from the inside only, the fillet throat must be at least equal to $1\frac{1}{4}$ times the smaller of $\frac{3}{4}$ in. (19 mm) or the thickness of either of the weld parts joined. There are also radial clearance restrictions similar to the Section VIII rules.

VOLUMETRIC EXAMINATION OF WELDS

Until Code Case 2235 was issued in 2005, ultrasonic examination (UT) methods were not often used for Section I construction. Code Case 2235 provided rules for the use of UT in lieu of radiography (RT) for Sections I, VIII Divisions 1 and 2, and XII. Until then, PW-11 limited the use of UT to electroslag welds in ferritic materials and to situations where the geometric unsharpness criteria in PW-11 were exceeded. The Case allowed the use of UT for welds $\frac{1}{2}$ in. (13 mm) thick or greater.

While still not used as much as RT, the use of UT is gaining in popularity. One of the reasons that UT is not more widely used is the extensive training and experience required for nondestructive examination (NDE) personnel to become proficient in the method and various techniques. This has been mitigated somewhat by the development of automated equipment used for weld examination. While still requiring highly skilled and experienced NDE personnel to operate, the newer equipment has made replicating an examination and obtaining the same results by different NDE personnel much easier. Another problem that has been resolved is the documenting or reporting of the examination results such that an independent third party can review the results without having to witness the examination in progress. Again, the latest equipment provides for recording the UT results while preventing any manipulation of the data by the NDE personnel performing the examination. These controls and other positive aspects regarding the use of UT prompted BPV I to incorporate the rules for UT into Section I.

The rules governing the use of UT were included in the 2010 Edition of Section I. Prior to that, PW-11 was titled Radiographic and Ultrasonic Examination of Welded Butt Joints. PW-11 is now titled Volumetric Examination of Welded Butt Joints.

As a general rule, Section I requires a volumetric examination of all longitudinal and circumferential butt welded joints. However, when the NDE method was restricted to RT, it was established that volumetric examination is not required for those types of weld joints for which it is not possible to do a meaningful RT examination. Examples of those types of weld joints include fillet welds, partial penetration welds, corner joints such as those illustrated in Fig. PW-9.2, and most of the nozzle attachment welds illustrated in Fig. PW-16.1. In order to obtain useful results from radiography, the thickness at the weld joint must not vary abruptly because potential flaws, such as lack of penetration, are recognizable by variations in a relatively uniform pattern of radiographic density. The joints just enumerated cannot, by their very nature, yield radiographs of uniform density. It could be argued that UT, or the use of the “digital radiography” technique, can

now provide a meaningful volumetric examination of such welds, but with decades of successful experience with these welds without volumetric examination, it is unlikely that BPV I will require volumetric examination of these welds in the future.

The paragraph that calls out the requirements for volumetric examination, PW-11, also grants a number of exceptions. Some of the most important exceptions are for circumferential butt welds in components that do not exceed certain sizes and wall thicknesses, depending on whether the contained fluid is water or steam and whether the welds are in contact with furnace gases or radiation from the furnace. Under these exemption rules, which are found in Table PW-11, most circumferential tube welds used in boiler and superheater tubes need not be examined volumetrically.

The same is true for circumferential joints in waterwall tubes of the furnace. In large boilers, the latter are usually fabricated into waterwall panels, which are joined end to end. Aligning these tubes when panel sections are welded together is somewhat difficult because the individual tubes in a given panel are not perfectly spaced, due to small variations in the welding process joining the fins to the tubes. The fins (also called membrane) between the tubes hold them rigidly together and prevent any adjustment for weld fit-up, so a short length of fin is left off at each end of the tubes until the panels are welded together. It is then possible to make slight adjustments to improve the fit of the tube ends. After completion of the butt welds, the omitted length of fin is installed. However, even after all this care is taken, the alignment of the tube ends is sometimes not perfect. It happens that Section I exempts most of these circumferential welds, which are in relatively small tubes, from volumetric examination. (The basis of this exemption is explained below.) Occasionally, a boiler owner decides to have the welds examined anyway, as a check on the quality of the welding. Any misalignment shows up as an indication of a potential flaw on the radiograph, and a dispute can then arise between the manufacturer and the owner as to whether the welds comply with Section I.

In 1983, such a situation led BPV I to issue Interpretation I-83-28, entitled Acceptance Standards When Radiography Is Not Required:

Question: When radiography is not required by Section I, but is used by the fabricator, must the acceptance criteria meet the requirements of PW-51?

Reply: No, it is the intent of Section I that radiographic standards for which Section I does not require radiography are outside the scope of the Code.

That same year BPV I provided further guidance about acceptance standards for butt welded joints that do not require radiography, in Interpretation I-83-79. The second question of that interpretation was as follows:

Question: What are the acceptance requirements for butt welded joints that are not radiographed, particularly in regard to the full penetration requirement?

Reply: PW-35 and PW-41.2.2 contain rules applicable to acceptance of butt welded joints that are not radiographed.

The paragraphs referred to, PW-35 and PW-41.2.2, call for full penetration at the root of the weld, noting that such penetration shall be demonstrated by the qualification of the welding procedure.

After several such disputes were brought to BPV I in the early 1990s, the committee revised the introduction to PW-11 to make it clear that this problem is not a Code question. It is, rather, a contractual matter between the manufacturer and the user. PW-11 now gives the following advice:

Welded butt joints requiring volumetric examination are specified in Table PW-11. Experience has demonstrated that welded butt joints not requiring volumetric examination by these rules have given safe and reliable service even if they contain imperfections that may be disclosed upon further examination. Any examination and acceptance standards beyond the requirements of this Section are beyond the scope of this Code and shall be a matter of agreement between the Manufacturer and the user.

Basis of Exemption from Volumetric Examination for Circumferential Welds

Section I exempts these circumferential welds from volumetric examination because the longitudinal stress in the tube crossing the welds is usually quite low. The tube is essentially a long cylinder, and in the absence of any local bending loads or axial loads other than pressure (which is usually the case), the axial pressure stress in a long cylinder is something less than half of the hoop membrane stress. Since the tube is designed for the hoop stress, the axial stress is less than half of the allowable stress. Thus, even if half the metal were missing at the weld (due, e.g., to lack of fusion or lack of penetration), there would still be enough metal remaining to carry the pressure stress in the axial direction without exceeding the allowable design stress. The tube on either side of the weld is capable of making up for some weakness in the weld with a slight increase in hoop stress. This is the equivalent of the ability of a cylinder to carry stress around a nozzle opening with a modest increase in local stress, as permitted by Section I's philosophy of designing for average hoop membrane stress.

There are occasions, however, when the axial stress due to superimposed mechanical loads can be significantly higher than the modest pressure stress mentioned above. Sometimes tubes are used as vertical supports, called stringer tubes, to support other, horizontal tubes, when the span of those tubes would otherwise be too long. Stringer tubes might typically be used in the heat recovery area of a boiler. The stringer tube is, in effect, a steam-cooled support out in the gas stream, where it is too hot to provide any other type of support. In that case, the designer must choose the weight to be carried so that the combined axial stress due to pressure and mechanical load does not exceed the allowable stress. The designer also has the option of using a thicker tube if needed to carry heavy loads.

Another instance of an axial stress adding to the stress caused by internal pressure can occur in waterwall tubes due to internal pressure in the furnace or external pressure on the outside of the furnace depending on whether the boiler is a forced draft or an induced draft unit. Some large utility boilers are designed with bag house filters as part of the flue gas cleanup system, and these filters can add a large pressure drop to the flow path through the boiler. As a result, the furnace walls could be subject to a pressure of as much as 36 in. of water. Even without bag house filters, a significant differential pressure can develop between the inside and outside of the furnace. Horizontal structural members, called buckstays, are provided on the outside of the boiler to carry this load. The tubes act as continuous vertical beams in carrying this differential pressure on the furnace wall to the buckstays. The tubes thus develop axial bending stresses that the designer must add to the axial pressure stress in the tube. Here, again, it is the designer's job to consider the differential pressure and the buckstay spacing and to select a spacing that will not overstress the tube.

Acceptance Standards for Volumetric Examination

Acceptance standards for volumetric examination are given in PW-51 (RT) and PW-52 (UT). Paragraph PW-51 invokes the radiographic examination procedures of Article 2 of Section V, and PW-52 invokes Article 4, Mandatory Appendix VII. Acceptance criteria for any imperfections disclosed by the examinations are provided in PW-51 and PW-52, respectively. There are four types of indications that are considered rejectable imperfections and must be removed after which the joint must be rewelded and reexamined. These four are:

1. Any indication characterized as a crack or zone of incomplete fusion or penetration.
2. Any other elongated indication on the radiograph greater than a certain length, which is a function of the thickness, t , of the weld.
3. For radiography, any group of aligned indications that have an aggregate length greater than t in a length of $12t$, except when the distance between the successive imperfections exceeds $6L$, where L is the length of the longest imperfection in the group.
4. Rounded indications larger than those shown in Appendix A-250.

Appendix A-250 provides detailed acceptance criteria for welds with rounded indications determined by radiography. The indications may be from any imperfection in the weld, such as porosity, slag, or tungsten.

The terminology paragraph of the appendix defines a **rounded indication** as one whose length does not exceed three times its width. Such an indication may be circular, elliptical, conical, or irregular in shape and may have a tail, in which case the tail must be included in the size evaluation. An indication with a greater length to width ratio than 3 is considered to be an **elongated indication**, whose acceptance is governed by the rules in PW-51.3.2. **Aligned indications** are defined in Appendix A-250 as a sequence of four or more rounded indications that touch a line parallel to the length of the weld drawn through the center of the two outer, rounded indications. Indications are further categorized as relevant and nonrelevant indications. A **nonrelevant indication** is one smaller than certain sizes given in A-250.3.2, which varies depending on the thickness, t . In this case, t is defined as the thickness of the weld, of the pressure retaining material, or of the thinner of the two sections being joined, whichever is least. Table A-250.3.2 of A-250 lists examples of the maximum size of nonrelevant indications and also the maximum size of acceptable rounded indications, both as a function of thickness, t . A **relevant indication** is one larger than the limit for a nonrelevant indication. There are also **isolated indications**, which are separated from adjacent indications by an inch or more, **random rounded indications**, and **clustered indications**, which show up to four times as many indications in a local area as are shown in the illustrations of random rounded indications.

Appendix A-250 contains a series of charts representing full-scale, 6-in. radiographs. These charts illustrate isolated, random, and clustered indications for different weld thicknesses. The charts represent the maximum acceptable concentration limits for rounded indications. Detailed acceptance criteria for the various types of indications are covered in the text of A-250. Although it is apparent that these rules are somewhat arbitrary, experience has shown that indications deemed acceptable do not harm the boiler.

NONDESTRUCTIVE EXAMINATION AND HYDROSTATIC TESTING

NONDESTRUCTIVE EXAMINATION

There are several related terms applied to Code construction that are somewhat imprecisely used. These are examination, inspection, and testing. Within the context of Section I, examination usually describes activities of the manufacturer; inspection refers to what the Authorized Inspector does; and testing refers to a variety of activities, usually of the manufacturer. Some confusion arises from the fact that nondestructive examination (NDE) includes activities defined as examinations, but which are often called tests. NDE is an indispensable means of assuring sound construction, since when properly used, these examinations are capable of discovering hidden flaws in material or welds.

The examinations referenced by Section I in the NDE category are radiographic examination, ultrasonic examination, magnetic particle examination, and liquid penetrant examination (also called dye penetrant examination). Although not explicitly mentioned in Section I, the use of visual inspection is certainly implied and is called out in B31.1 for application to the boiler external piping. These examinations are often referred to in the industry by the shorthand terms RT (radiographic test), UT (ultrasonic test), MT (magnetic particle test), PT (penetrant test), and VT (visual inspection).

Section I generally follows the Code practice of referring to Section V, Nondestructive Examination, for the rules on how to conduct the various examinations, but provides its own acceptance standards. For example, PW-11 calls for certain welds to be examined in accordance with Article 2 of Section V, to the acceptance standard of PW-51. Similarly, PG-25, Quality Factors for Steel Castings, calls for magnetic particle or dye penetrant examination of all surfaces of castings in accordance with Section V, but provides acceptance criteria right there in PG-25.

QUALIFICATION AND CERTIFICATION OF NDE PERSONNEL

Personnel performing and evaluating radiographic, ultrasonic, and other nondestructive examinations are required to be qualified and certified as examiners in those disciplines in accordance with a written practice of their employer (PW-50). This written practice must be based on either SNT-TC-1A, *Recommended Practice for Nondestructive Testing Personnel Qualification and Certification*, or CP-189, *Standard for Qualification and Certification of Nondestructive Testing Personnel*, both published by the American Society for

Nondestructive Testing. (Note the use of the word testing rather than examination in this title, showing again that the industry tends to use these terms interchangeably.) Both SNT-TC-1A and CP-189 are revised periodically. The latest approved editions are found in Table A-360. The documents establish three categories of examiners, depending on experience and training, designating them as Level I, II, or III, with Level III being the highest qualification. The lowest ranking examiner, Level I, is qualified to perform NDE following written procedures developed by Level II or Level III personnel. A Level I individual can also interpret and accept the results of nondestructive examinations in accordance with written criteria (except for RT and UT examinations). A Level II individual has sufficient additional training and experience so that under the direction of a Level III person, he or she can teach others how to conduct, interpret, and accept the results of nondestructive examinations. A Level III examiner is the most qualified and can develop and write procedures, as well as establish a written practice for his or her employer. A Level III examiner can also administer examinations to qualify Level I, II, and III examiners.

In the earlier editions of SNT-TC-1A, it was possible for examiners experienced in performing tests, and in developing and writing NDE procedures, to be qualified as Level III examiners on the basis of that experience, and many individuals were so qualified, without having to pass an examination. In 1992, the requirements were tightened, and the practice of grandfathering based on experience was no longer permitted. To become a Level III examiner, it was necessary to pass an appropriate examination. This caused a problem when a Level III examiner who has never had to take an examination is subject to periodic review (every 5 yr) for renewal of certification and, in some cases, is told that he or she must now take an examination.

One approach taken by BPV I to resolve this problem was to issue Interpretation I-98-06 in response to an inquiry regarding testing Level III NDE personnel. It read:

Question: Under the incorporation of the 1992 edition of SNT-TC-1A by Section I of the Boiler and Pressure Vessel Code, is it necessary to examine currently certified Level III individuals to comply with this edition?

Reply: No.

This issue was later reconsidered by BPV I citing concerns that the interpretation was an example of “Code rules by interpretation.” In the 2004 Addenda, PW-50 was revised to read “Qualification of NDE Level III personnel certified prior to the 2004 Edition of Section I may be based on demonstrated ability, achievement education and experience. Such qualifications shall be specifically addressed in the written practice.” This made it clear that the qualification of new Level III personnel during or after the 2004 Edition of Section I required an examination.

PW-51 requires a complete set of radiographs for each job to be retained and kept on file by the manufacturer for at least 5 yr. This requirement is based on the reasonable idea that the radiographs might be of assistance in determining responsibility (or lack of responsibility) for any defects, alleged or actual, subsequently discovered, or other problems that might occur in service. Similarly, PW-52 requires a manufacturer who uses ultrasonic examination to retain a report of that examination for a minimum of 5 yr. Again, these records might prove useful should problems occur in service.

HYDROSTATIC TESTING

The hydrostatic test is one of the last steps in the construction of the boiler. Hydrostatic test requirements are given in PG-99, PW-54, PMB-21 and PEB-17. These tests may be made either in the manufacturer’s shop, or in the field, using water. Unlike Section VIII, Section I does not permit the use of other fluids or pneumatic testing.

The hydrostatic test serves a number of purposes. Many members of the Code committees believe that its major purpose is to establish that the boiler (or pressure vessel) has been properly constructed and that it has

a significant design margin, or safety margin, above and beyond its nominal maximum allowable working pressure. (The hydrostatic test pressure is normally 1.5 times MAWP.) In this sense, the hydrostatic test is seen to demonstrate the validity of the design as a pressure container. They also believe another important aspect of the hydrostatic test is that it serves as a leak test. Any leaks revealed by the test must be repaired, and the boiler must be retested (see PW-54). Others believe a more important benefit resulting from the hydrostatic test is a redistribution of stresses at locations of stress concentrations formed during fabrication of the boiler. As explained by Mr. George Galanes in his article *Pressure Testing: Fact and Fiction* found in the fall 2004 National Board Bulletin, "During the . . . hydrostatic test, the bulk of new material is subject to stress levels below the yield point of the material and most service stresses. However, at local areas of stress concentration from openings and appurtenances, the new material under pressure during a hydrostatic test can experience loads that exceed the yield strength, resulting in a redistribution of the stresses" which "locally strengthens the material prior to being placed into service." There are others that disagree that the benefit of such residual compressive strength has any lasting benefit for boilers because of the high operating temperatures. In any case, the requirement for performing a hydrostatic test is unlikely to be removed at anytime in the foreseeable future.

The first Edition of Section I in 1915 called for a hydrostatic test at 1.5 times the maximum allowable working pressure, a basic rule essentially unchanged to this day. We may surmise that the choice of this pressure followed the practice of the time and was seen to provide evidence that the boiler had been constructed with a significant design margin. It is worth noting a bit of hydrostatic testing history provided in correspondence from the Chair of BPV I, Mr. David L. Berger. He explained that in 1931, when Section I first permitted the use of load-bearing welded construction, the hydrostatic testing requirements included pressure testing at 1.5 times the MAWP while the inspector struck the vessel sharply with a hammer at 6-in. (150-mm) intervals adjacent to the weld for the full length of the weld. After that, the boiler was to be pressurized to 2 times the MAWP and held at that pressure while being examined for leaks. As Mr. Berger opined, it appears that the engineering community of that era did not have a good understanding of the brittle fracture phenomenon.

Prevention of Brittle Fracture

PG-99 requires the hydrostatic test to be conducted using water "at not less than ambient temperature, but in no case less than 70°F (20°C)." This stipulation about the water temperature is intended to minimize the possibility of catastrophic brittle fracture of heavy-walled pressure parts during the test. (The exception to this rule found in PMB-21 is described in the next section of this chapter, Miniature Boilers.) Brittle fracture is a type of behavior that can occur when metal is under tensile stress when its temperature is at or below its so-called **nil ductility transition temperature** (NDTT). Above this temperature, the metal behaves in a ductile manner; below this temperature its behavior is brittle. Contrasting examples of these two types of behavior are the bending of a wire hanger compared with the bending of a glass rod. The wire, which is ductile, bends easily when its yield strength is exceeded and can be restored to its original shape. The glass rod can carry a certain amount of bending load, but then suddenly fractures in a brittle manner when its yield strength is reached.

Any flaw, notch, or other discontinuity can raise stress at some local area to the yield point. If the material is ductile, it can yield locally, with little harm done. If the material is below its NDTT, it behaves in a brittle manner; when stress reaches the yield point, the material may tear or form a crack, which can then grow suddenly through the thickness causing a catastrophic failure. The ability of a material to resist tearing or cracking is a measure of its fracture toughness.

Brittle fracture is generally not a concern for relatively thin materials. The manufacturers of steels used in boilers have developed melting practices that usually result in nil ductility transition temperatures well below 70°F (20°C), assuring adequate fracture toughness during hydrostatic tests. The component of greatest

concern in a large utility boiler (so far as brittle fracture is concerned) is the drum, since it has very thick walls. (It happens that thick vessels and headers are more susceptible to brittle fracture than thinner components.) After a number of brittle failure accidents in the 1970s, the manufacturers of large boilers took steps to lower the NDTT of heavy-walled parts such as drums by slightly modifying specifications for material ordered to achieve a finer grained material with greater fracture toughness. Also, in some instances, the manufacturers of large boilers recommended to their customers that any future hydrostatic tests of existing boilers be conducted using warm or even hot water, to assure ductile behavior at the time of the test. This became potentially hazardous for the Authorized Inspector, and BPV I placed a 120°F (50°C) limit on metal temperature during the hydrostatic test at the request of the National Board. Also around this time, some boiler manufacturers switched from the use of SA-515 to SA-516 plate for heavy-walled boiler drums because the latter has greater fracture toughness. Even so, heavy SA-516 plate is often examined metallurgically by boiler manufacturers to determine its NDTT, and if that temperature is not well below 70°F (20°C), a hydrostatic test using water warmer than 70°F (20°C) is recommended.

The concerns described above can be illustrated by considering the design of a thick-walled drum for a large high-pressure boiler made of SA-516 grade 70 plate. The allowable stress used for designing the drum is about 19 ksi (127 MPa). Accordingly, during the hydrostatic test, the actual average membrane stress in the drum wall is approximately 1.5 times 19 ksi (127 MPa), or 28.5 ksi (190 MPa). At first glance, this seems to be a reasonable margin below the cold yield strength of this material, which is about 38 ksi. Unfortunately, this is not the case because in a real vessel, there are always irregularities of various kinds present that act as stress raisers. Examples include welds with undercuts, grooves, or ridges. Ligaments between openings can also act as stress raisers, as can changes in vessel geometry at transitions between materials of different thickness and at nozzle-to-shell junctions. These stress-raising irregularities, sometimes loosely called notches, may cause a stress concentration of two or more. Thus, in a drum undergoing hydrostatic testing, it is very likely that local surface stress at some of these notches may approach or exceed the yield stress. At such a time, it is important that the boiler plate material be warm enough for its behavior to be ductile, so that local yielding can occur without significant danger of initiating a brittle failure. When the boiler is in normal service, it is, of course, at a temperature that ensures ductile behavior. It is also at a pressure much lower than that during the hydrostatic test, so that the stress, even at notches, is likely to be well below the yield stress.

Test Pressure for Drum-Type Boilers

For most boilers, the hydrostatic test is conducted by slowly raising the pressure to 1.5 times the MAWP. Close visual inspection is not required during this stage, in the interest of safety of the Inspector. The pressure is then reduced to the MAWP, and the boiler is carefully examined for leaks or other signs of distress.

In the 1999 Addenda of the ASME Code, the design factor based on material strength was reduced from about 4 to about 3.5. This resulted in the increase of allowable design stresses below the creep range for many materials used in Section I construction. BPV I assigned a task group to investigate the ramifications of what would be a modest increase in some design stresses. The hydrostatic test pressure was one of the issues considered. On completion of the investigation, BPV I concluded that a reduction in hydrostatic test pressure was unnecessary, but it was agreed that the wording in PG-99 should be modified to address the potential of exceeding the yield strength of certain materials during the hydrostatic test. PG-99 now requires that at no time during the test shall any part of the boiler be subjected to a primary membrane stress greater than 90% of its yield strength. The paragraph also advises the designer to take into account the primary membrane stress to which each component will be subjected when designing the boiler. These rules, first seen in the 1999 Addenda, were chosen to make clear that the goal is to limit average membrane stress through the wall of the components, and not the bending stress or peak stress at the surface.

Hydrostatic Tests for Miniature Boilers

Miniature boilers are classified as boilers that do not exceed the limitations described in PMB-2:

- 16 in. (400 mm) inside shell diameter
- 20 ft² (1.9 m²) heating surface
- 5 ft³ (0.14 m³) gross volume
- 100 psig (700 kPa) MAWP

For these boilers and electric boilers meeting the above restrictions (see PEB-17), the typical hydrostatic testing requirements have been modified to a great extent. Each miniature boiler pressure vessel must be inspected while being hydrostatically tested at three times the MAWP. When the shell thickness of the boiler is 3/8 in. (10 mm) or less, and when P-No. 8 or certain P-No. 1 materials are used for the pressure vessel, permission is given to perform the hydrostatic test with a minimum metal temperature of 60°F (15°C). Note that a minimum *metal* temperature is stipulated, not a water temperature.

Forced-Flow Steam Generators with No Fixed Steam and Waterline

The usual hydrostatic testing procedure is modified for forced-flow steam generators with no fixed steam and waterline. These boilers are designed for different pressure levels along the path of water-steam flow, with a significant difference between economizer inlet and superheater outlet. In one such boiler, for example, those design pressures were 4350 psi (30 MPa) and 3740 psi (26 MPa), respectively. The design pressure or MAWP at the superheater outlet is the design pressure stamped on this type of boiler and is called the master stamping pressure. In the first stage of the hydrostatic test, a pressure equal to 1.5 times the **master stamping pressure** (but no less than 1.25 times the MAWP of any other part) must be applied. In the example given, the 1.5 factor controls, at 5610 psi (39 MPa). For the second or close examination stage, the pressure may be reduced to the MAWP at the superheater outlet.

The somewhat different treatment for hydrostatic tests of forced-flow steam generators with no fixed steam and waterline comes about from several factors peculiar to this type of boiler as compared to the natural circulation type. If the former type were tested at 1.5 times the MAWP of its component with the highest design pressure, the result would be excessive and might cause yielding of some other components. In the example cited, the test pressure would have been 1.5 times 4350 psi (30 MPa), or 6525 psi (50 MPa) rather than 5610 psi (39 MPa). The committee compromised by requiring a test at 1.5 times the master stamping pressure, with the proviso that no part should be tested at less than 1.25 times its MAWP. This provides a leak test and demonstrates an adequate design margin for this type of boiler, which has no drum, and whose pressure is controlled by a pump, not by firing rate.

Heat Recovery Steam Generators

In recent years, gas turbines with heat recovery steam generators (HRSG) have assumed increasing importance in energy conservation programs. As a consequence, HRSG with new configurations and design arrangements have evolved. Some of these boilers have multiple circuits with different design pressures, with low, intermediate, and high pressure. These circuits are often equipped with valves allowing them to be isolated for servicing or during certain operating conditions. For such boilers, each independent design pressure circuit is given a separate hydrostatic test at 1.5 times its design pressure (MAWP). There are, however, other types of HRSG in which the various components along the flow path from economizer inlet to superheater outlet are designed for different pressures even though there are no intervening valves between the different pressure zones. In 1990, BPV I received an inquiry asking whether the rules for hydrostatically testing a forced flow steam generator could be applied to a natural circulating heat recovery steam generator (i.e., 1.5 times the MAWP but not less than 1.25 times the MAWP of any part of the boiler). The inquirer reasoned

(incorrectly) that because the boiler had no fixed steam and water line and had pressure parts designed for different pressure levels along the water-steam flow path, the rules should apply. BPV I requested additional information from the inquirer and subsequently learned that the boiler in question had a drum, therefore a fixed water line. The pressure dropped at each stage along the water-steam path with the lowest pressure being at the final stage steam outlet. The inquirer was under the misconception that the boiler had to be tested at 1.5 times the highest MAWP of any part of the boiler. Ultimately, it was decided that what the inquirer really wanted to know was how to establish the MAWP for this natural circulation boiler. The committee advised in Interpretation I-89-68 that the MAWP to be stamped was the lowest of the several design pressures used, and the hydrostatic test pressure was to be 1.5 times that pressure. It is quite clear that with no intervening valves, there is no way to conduct tests at different pressure levels, and the lowest design pressure zone establishes and limits the hydrostatic test pressure to be applied.

WELDING AFTER HYDROSTATIC TEST

Formerly, the hydrostatic test completed the construction of the boiler, and no further work (i.e. welding) was permitted. However, around 1980, the Committee added provisions to PW-54 permitting nonpressure parts to be welded to the pressure parts after the hydrostatic test, if certain conditions were met. At that time, welding was limited to P-No. 1 materials; attachment was to be done by stud welds or small fillet welds; a 200°F (95°C) preheat was to be applied when the thickness of the pressure part exceeds 3/4 of an inch (19 mm); and the completed weld was to be inspected by the Authorized Inspector before he or she signed the Manufacturer's Data Report Form for the completed boiler. Those rules still apply, but in the 2002 Addenda, they were expanded to allow certain seal welding of pressure retaining parts such as hand-hole caps and inspection plugs or fittings secured by physical means. In the 2003 Addenda, the rules were further clarified to include carbon steel nonpressure attachment material with a carbon content of 0.2% or less and all P-No. 1 material. These provisions granted relief from delays that arose when miscellaneous welding to the pressure parts was not completed for various reasons when the pressure parts were ready for the hydrostatic test.

INTERPRETATIONS ON HYDROSTATIC TESTING

Over the years, there have been quite a few other inquiries about various aspects of **hydrostatic testing** not explicitly covered by PG-99. BPV I's replies to these inquiries now form a useful body of information. Some of the more important of these are reviewed below.

Same Hydrostatic Test Pressure Used for All Parts of the Boiler

Occasionally, someone raises a concern as to whether the usual hydrostatic test pressure of 1.5 times MAWP is appropriate for the feedwater, blowoff, and main steam piping, since that piping does not have the same design pressure as the boiler. As explained in Chapter 5, the feedwater and blowoff piping design pressure is as much as 225 psi (1.6 MPa) higher than the MAWP of the boiler, and the main steam piping may be designed for a pressure lower than the MAWP of the boiler. Thus, the normal hydrostatic test is less than 1.5 times design pressure for the feedwater and blowoff piping and may be more than 1.5 times design pressure for the main steam piping.

A little thought shows this concern is groundless. Remember first that the feedwater and blowoff piping have been deliberately made stronger than the rest of the boiler to account for their so-called shock service, by arbitrarily increasing their design pressure. Then consider that the 1.5 times MAWP hydrostatic test pressure is also an arbitrary value, which has been in the Code since 1915, when today's nondestructive examina-

tions and quality control systems were not available. From the preceding discussion of hydrostatic test rules for forced-flow steam generators with no fixed steam and waterline (which date from the mid-1960s), it is clear that BPV I accepts a hydrostatic test of 1.25 times MAWP in certain circumstances. There is also a precedent for tests at lower pressure, in Section VIII, which permits pneumatic testing at 1.25 times MAWP as an alternative to a hydrostatic test at 1.5 MAWP.

Consider now the main steam piping, for which the standard hydrostatic test might exceed 1.5 times the piping design pressure. Is this a real concern? Would the stresses during the test be too high? A little thought shows they would not because the main steam piping is usually designed for high-temperature service, using allowable stresses that are typically only about half of those permitted at hydrostatic test temperature. Thus, during the hydrostatic test, the stress in the main steam piping would probably not even reach the cold allowable stress.

Note also that PG-99 makes no mention of different hydrostatic test pressures for different parts of the boiler. It simply instructs that a single test pressure is to be applied to the completed boiler (which of course includes the boiler external piping). Thus, in 1981, when an inquirer asked if it were permissible to test a main steam line in just such a situation, i.e., the boiler MAWP was higher than the design pressure of the main steam piping, BPV I replied yes, the main steam line may be hydrostatically tested with the boiler as outlined in PG-99. (See I-82-11, Maximum Hydrotest Pressure for Drum-Type Boilers in Interpretations No. 11.) PG-99.1 offers guidance on conducting the hydrostatic test. It specifies that the pressure should be raised gradually to 1.5 times the MAWP and that no part of the boiler be subjected to a general membrane stress greater than 90% of its yield strength. As a safety precaution, it also notes that close visual inspection is not required when the boiler is at full test pressure.

Exceeding the Hydrostatic Test Pressure

During a typical hydrostatic test, the boiler is first filled with water using a pump capable of providing a large volume of water at relatively low pressure. Various vents are left open to permit all the air to escape, and when the boiler is full of water, all valves are closed and a different kind of pump is used, one that can achieve the high pressure required. Often the pump used for the hydrostatic test is a piston-type pump that slowly builds pressure as any remaining air pockets are filled with water. When the water-holding volume of the boiler reaches the stage where it is essentially solid water, each piston stroke raises the pressure substantially, due to the essentially incompressible nature of water. Until the 1999 Addenda, the rule regarding hydrostatic test pressure stated that the test pressure must not be exceeded by more than 6% [i.e., not more than $(1.06)(1.50)(\text{MAWP}) = (1.59)(\text{MAWP})$]. Under those rules, it was difficult to achieve the desired test pressure without overshooting the mark; therefore, PG-99.1 permitted the test pressure to be exceeded by 6%. Test personnel had to be extremely attentive at this time to avoid exceeding this 6% test pressure tolerance.

As might be expected, the maximum permitted hydrostatic test pressure was occasionally exceeded, and in a few cases, the Authorized Inspector had refused to accept the boiler because PG-99.1 said that the desired test pressure was *never* to be exceeded by more than 6%. What to do? Inquiries came to BPV I, where the sentiment was on the side of common sense, namely, that if the manufacturer could demonstrate to the AI, by some means, perhaps calculations that stresses during the test had not exceeded the yield strength of the parts, and no damage had been done to the boiler, the AI could accept the boiler. In 1981 Interpretation I-81-27, Maximum Hydrostatic Test Pressure, was issued, as follows:

Question: Under what circumstances may the hydrostatic test pressure stated in PG-99 be exceeded?

Reply: The test pressure may be exceeded when the manufacturer demonstrates to the satisfaction of the Authorized Inspector that no component has been overstressed.

That interpretation remained valid until the changes to PG-99 were made in the 1999 Addenda.

As explained earlier in this chapter in Test Pressure for Drum-Type boilers, changes to rules regarding maximum test pressure were made in response to reducing the design factor based on material tensile strength from 4 to 3.5. The rules still require a minimum test pressure of 1.5 times the MAWP but no longer set a maximum test pressure. Instead, the rules now require that no part of the boiler shall be subjected to a general membrane stress greater than 90% of its yield strength. The manufacturer is cautioned that the primary membrane stress must be taken into account when designing the components. Test personnel are still wise to be extremely attentive when pressurizing the boiler to assure the test pressure of 1.5 times the MAWP is not exceeded by a substantial amount. The 6% overpressure margin remains a good rule of thumb to go by.

Hold Time for Hydrostatic Test

In 1980, an inquirer asked how long the hydrostatic test pressure should be held at 1.5 times the MAWP. BPV I responded in Interpretation I-80-15 that the pressure was to be maintained an amount of time satisfactory to the Authorized Inspector and then reduced to the MAWP at the Inspector's discretion for close examination of the boiler.

Pressure Drop During Hydrostatic Test

In the same Interpretation (I-80-15), the inquirer asked whether a pressure drop was permitted during the hydrostatic test. BPV I replied that the pressure was to be maintained at the MAWP, while the boiler is examined. In effect, the committee was advising that a slight pressure drop was permissible so long as the pressure did not fall below the MAWP. The pressure drop presumably would be caused by some slight leakage in the water supply system, not through any welds or pressure part material, which would represent failure of the test. This point was explained further in the following Interpretation.

Slight Leakage Through Valve Seats During Hydrostatic Test

In 1992, an inquirer asked whether slight leakage through the seat of a closed valve was permissible during the hydrostatic test. BPV I responded in Interpretation I-92-56 that such leakage was permissible. This was a typical case of the committee's practical approach based on the field experience of its members, who were satisfied that such leakage was not uncommon and did not invalidate the test. The inquirer had a logical follow-up question, as explained next.

Use of Pump to Maintain Hydrostatic Test Pressure

The inquirer of Interpretation I-92-56 asked also whether a pump may be used to maintain pressure during the hydrostatic test (during which some slight leakage through valve seats was taking place), so long as the test pressure was maintained within the limits prescribed by PG-99. Again, on the basis of its practical experience, BPV I saw nothing wrong with such a practice.

Minor Leakage from Mechanical Joints During Hydrostatic Test

In September 1997, BPV I answered an interesting inquiry about the purpose of the hydrostatic test and whether some minor leakage through mechanical joints (such as a rolled tube joint) could be permitted. Interpretation I-98-07 was issued as follows:

Question: *Is the purpose of the hydrostatic test required by PG-99 of Section I to demonstrate the strength and integrity of the boiler and to detect leakage?*

Reply: *Yes.*

Question: *Is it acceptable to have minor leakage from mechanical joints during the hydrostatic test?*

Reply: *Yes, if acceptable to the Authorized Inspector.*

After careful consideration and discussion, the committee was persuaded that the answer to the second question was in accord with industry practice and would provide guidance to the Authorized Inspector in exercising his or her judgment, while still leaving the Inspector ultimate responsibility for acceptance of the test.

Location and Type of Test Gages

There have been a number of interpretations clarifying the application of test gages used during the hydrostatic test.

Interpretation I-78-27 explained that the test gage does not have to be mounted directly on the pressure parts. This interpretation also permits the use of a single test gage installed in the system near the pump to be used for the hydrostatic test of a number of components connected in series.

In a similar situation, Interpretation I-89-58 explains that the required test gage may be mounted anywhere on the line between the pump and the pressure parts or on a manifold connecting several pressure parts undergoing hydrostatic testing. The same inquirer also asked whether it was necessary for the test gage to be mounted at the highest point on the pressure parts being tested. The committee responded that this was not necessary, but cautioned that the hydrostatic head on the gage must be taken into account when conducting the test. In the 2003 Addenda, PG-99.4.1 was revised to clarify that the hydrostatic head on the gage had to be considered *such that the required pressure be achieved at the top of the boiler*.

Reflecting the steady improvements in modern technology, an inquiry was submitted to the committee in 1992 asking if it was permissible to use a pressure transmitter with a remote readout in lieu of a digital pressure gage, provided the readings gave the same or greater degree of accuracy as obtained with a dial pressure gage. BPV I replied in Interpretation I-92-52 that the use of such devices was permissible, provided the remote pressure readout was visible to the operator controlling the applied pressure. Implicit in this interpretation is the acceptance of a digital gage whose accuracy is equal to that of a conventional dial gage.

An inquiry on test pressure gages in 1993 asked whether PG-99.4.2 restricted the range of the gage to double the intended maximum test pressure. Since the paragraph in question uses nonmandatory language, the committee could only reply in the same vein, that the maximum range of the gage should preferably be about double the maximum test pressure.

Subsequent Hydrostatic Tests

A 1980 inquiry asked whether any subsequent hydrostatic tests were required after the initial hydrostatic test performed by the boiler manufacturer. BPV I in Interpretation I-80-15 replied with this advice:

Subsequent inservice inspection hydrostatic test pressures are not addressed in Section I, which is for new construction only. Such subsequent tests must follow the requirements of the jurisdiction in which the boiler is operating.

Another interpretation on the subject of subsequent hydrostatic testing deals with a boiler that was completely assembled and hydrostatically tested in the shop. The Authorized Inspector then signed the Master Data Report. The boiler external piping was subsequently disassembled for shipment. The question was whether Section I required a further hydrostatic test after reassembly of the same components. BPV I replied

in Interpretation I-89-51 with a fundamental tenet of the Code: After the Authorized Inspector has signed the Master Data Report for a complete boiler, the boiler is no longer under the jurisdiction of the Code. Accordingly, no further testing is required.

Hydrostatic Testing of Boiler External Piping

An inquiry on hydrostatic testing of boiler external piping asked whether the rules for such testing, including test temperatures, were those found in PG-99 of Section I. In Interpretation I-83-64, the committee replied in the affirmative. As explained in Chapter 1, the boiler external piping is part of the complete boiler unit and is hydrostatically tested with the complete boiler, even though most design and construction rules for this piping are found in the B31.1, Power Piping Code. However, B31.1, paragraph 137.3 on pressure testing simply refers to PG-99 and notes that the testing must be conducted in the presence of the Authorized Inspector. This reminder was included because B31.1 normally does not require third-party inspection of the piping it covers. Further discussion of potential problems associated with hydrostatic testing of boiler external piping and valves can be found in the Special Considerations section of Chapter 5.

Temperature Ratio Applied to Hydrostatic Test Pressure

An unusual inquiry was received in 1984, asking whether the temperature ratio of Appendix A-22.8 had to be applied to the hydrostatic test pressure. It should be explained that this temperature ratio approach is used by Section VIII for establishing hydrostatic test pressure. Section VIII required the basic 1.5 times MAWP (currently 1.25 MAWP) test pressure to be further increased (multiplied) by the lowest ratio (for the vessel materials) of the allowable stress value S at test temperature to the allowable stress value at design temperature. This can be a significant multiplier if the vessel is designed for high-temperature service. However, BPV I has never considered that such a multiplier was necessary for Section I construction. (The authors concur with this view, which has been borne out by many years of satisfactory experience.) Section I requires the use of the temperature ratio only for the determination of maximum allowable working pressure by proof test under the proof testing provisions of Appendix A-22. That was the substance of the reply published in 1984 as Interpretation I-83-92.

Applying Insulation Before Hydrostatic Test

There have been several interpretations dealing with the question of applying insulation to the boiler before the hydrostatic test. The concern in this situation was the possibility that the insulation or refractory might cover a leak that the Inspector otherwise might find during the test. The first of these inquiries came in 1985 and asked if it was permissible to test sections of a boiler in the shop at MAWP (as a leak test), then to apply insulation and ship the insulated sections to the field, where they would be assembled and given a hydrostatic test in accordance with PG-99. In Interpretation I-86-01 (later reversed by I-89-21), the committee said this was not permissible because all surfaces must be available for inspection during the hydrostatic test. Four years later, BPV I received a closely related and somewhat more narrowly stated inquiry that was answered in Interpretation I-89-21:

Question: May portions of welded power boilers that do not contain longitudinal welded joints made with the addition of filler metal be covered with insulation or refractory prior to the hydrostatic test required by PG-99?

Reply: Yes; however, the Authorized Inspector may require the hydrostatic test pressure to be maintained at the maximum allowable working pressure for an extended period of time, sufficient to assure there is no indication of leakage. The Authorized Inspector may also require removal of insulation for cause.

The committee discussion that finally led to an agreement on this reply covered a number of issues. Several members of the committee who had disagreed with the assertion in Interpretation I-86-01 that all surfaces must be available for inspection during the hydrostatic test pointed out that in large utility boilers, it is not only unnecessary but well nigh impossible for the Inspector to see all surfaces during the hydrostatic test. It was the opinion of some that a leak will soon make itself known, whether it is behind refractory and insulation, or at a stub-to-header weld, or wherever it might be. It was argued that such a leak is hardly a major safety hazard, it is simply a minor problem requiring repair, and it is the boiler manufacturer's responsibility to see to it that any leaks are repaired. Thus, the manufacturer who installs insulation and refractory before the hydrostatic test does so for its own convenience and at its own risk. The committee was finally able to agree on the above reply, once language was included in it to caution that the Inspector could call for the pressure to be maintained for an extended time to assure there was no indication of leakage and could also require the removal of insulation if there was such an indication.

Thus, Interpretation I-89-21 effectively reverses the assertion in Interpretation I-86-01 that all surfaces must be available for inspection during the hydrostatic test.

Painting Before Hydrostatic Test

In a somewhat related inquiry about painting before the hydrostatic test, the committee had no trouble in agreeing that this was permissible and said so, in Interpretation I-86-69 in January 1988. The members knew that painting pressure parts before testing was a routine practice and that no significant leak could be prevented or hidden by painting.

Hydrostatic Test Procedures

There have been a few inquiries about procedures to be used during the hydrostatic test. In 1986, an inquirer asked whether Section I prohibited a pneumatic pressurization of the boiler system before performing the required hydrostatic test. The committee replied in Interpretation I-86-42 that such a test was not prohibited, but added a caution that pneumatic tests may be hazardous and recommended that special precautions be taken.

Another procedural question was whether it was permissible to conduct a hydrostatic test of a boiler by filling it completely with water, connecting it to a vessel that is partially filled with water, and then pressurizing that vessel with air or another gas. The committee replied in Interpretation I-89-19 that the means by which hydrostatic pressure is applied are beyond the scope of Section I. In other words, Section I does not prohibit such a procedure.

Hydrostatic Test of Mechanically Assembled Boiler External Piping

For quite some time, BPV I struggled with a number of issues having to do with boiler external piping assembled by mechanical means, i.e., without welding. Two issues pertinent to the deliberations were whether this type of piping requires the usual hydrostatic test as part of the complete boiler unit and whether it is necessary to have an Authorized Inspector witness and sign for a hydrostatic test of such piping. The committee was somewhat ambivalent in its replies because of a tradition that the installation of threaded piping could be safely left to a plumber or others not authorized to engage in Section I construction. Support for that tradition can be found in Note 2 of PG-104.1, which apparently exempts organizations that install boiler external piping by mechanical means (as opposed to welding) from the requirement to provide Code certification and stamping for it. However, the committee has issued a number of interpretations since about 1990 saying that an Authorized Inspector has to witness the hydrostatic test of the completed boiler even if the boiler external piping is assembled by mechanical means. In late 1997, after long and difficult deliberations, a series of

changes to PG-99, PG-104.1, PG-112.2.2.5, and A-357, a new PG-109.4, and a new alternative form P-4B were approved. The new rules explained that mechanically assembled piping need not be assembled by a Code symbol holder, but that responsibility for documentation and hydrostatic testing of such piping must be assumed by the holder of an S, A, or PP stamp. This would include a hydrostatic test, witnessed by an Authorized Inspector. The new provisions and the new form P-4B appeared in the 1998 Addenda included in the 1998 Edition of Section I.

THIRD PARTY INSPECTION

What is third party inspection and why is it mandatory for Section I construction? In the simplest terms, third party inspection refers to the system evolved by the Code committee to assure that code rules are actually followed. That is a basic truth, but it does not fully answer the question regarding why it is mandatory. It is not mandatory for other code constructions such as that governed by ASME B31.1, so why is it so for Section I construction? The answer is twofold; (1) to assure consistent, uniform application of code rules thus assuring a certain degree of safe equipment as well as easing interstate and international trade and (2) to protect the use of the ASME marks (e.g., Code symbol stamps).

In the early days of the ASME boiler code, it was not uncommon for each state or jurisdiction to have its own boiler inspection requirements. Because there were no uniform requirements between the states for stamping of boilers, or uniform system for qualifying inspectors and applying Code rules, a boiler manufacturer in one state often had to have its boiler inspected and accepted by the inspector from the state in which the boiler was to be installed. This was a big burden to commerce in general and the boiler manufacturers in particular. It could be argued that this also impacted safety of the equipment due to the differing degrees of expertise of the inspectors regarding understanding and application of Code rules. These conditions led to the formation of the National Board of Boiler and Pressure Vessel Inspectors (National Board) which, with the support of the American Boiler Manufacturers Association (ABMA) and the Uniform Boiler and Pressure Vessels Laws Society, brought about a system for uniform examination of inspectors, consistent application of Code rules and uniform rules for stamping of boilers (i.e., the use of the ASME Code symbol, or mark). This greatly eased the manufacturers' burden of obtaining multiple inspections and stampings and thus making interstate commerce much more efficient. It also added to the general welfare by assuring the public of the uniform application of Code rules.

The ASME Boiler and Pressure Vessel Code symbols (e.g., S, U, PP, V, etc.) are, by ASME policy, referred to as ASME "marks." In 1992, the ASME added a new Codes and Standards Policy (CSP) called CSP-53, Policy on Protection of ASME Marks. In brief, this policy states:

1. All ASME programs that specify the use of an ASME mark (e.g., Code symbol) shall provide for designated oversight (i.e., third party inspection) of those activities affecting the proper use of the marks.
2. Third part inspection shall comply with ASME-developed criteria which shall establish reasonable assurance that use of the marks is in accordance with the appropriate code or standard.
3. Third party inspection shall be by one or more of the authorized types:
 - a. An ASME accredited authorized inspection agency (AIA) via use of authorized inspectors (AI);

- b. An ASME qualified inspection organization (QIO) via the use of qualified inspectors (QI); or,
 - c. A certified individual (CI) employed, qualified and certified by an organization authorized by ASME to use its marks (e.g., Code Symbol stamp holder).
- 4. The use of the marks is to be documented with data reports or certificates of compliance, signed by the stamp holder and the third party inspector.
 - 5. The data reports and certificates of compliance are to be retained for a period of time established by the appropriate code or standard.

At this writing, Section I provides for third party inspection via a Certified Individual (CI) or an Authorized Inspector (AI). A CI is permitted to be used by valve manufacturers authorized to use the “V” Code symbol (refer to Section I, PG-73.7) and electric boiler manufacturers authorized to use the “E” Code symbol (refer to Section I, PEB-18.5). This type of inspector was authorized by ASME because, until the adoption of CSP-53, the valve and electric boiler manufacturers were not required to have a third party inspector witness the final testing of each piece of equipment to which the Code symbol was applied. The expense of contracting with an AIA and utilizing an AI was considered an undue burden on these organizations. It was considered sufficient for the protection of the mark that the CI merely be an employee of and qualified and certified by these organizations. The duties of the CI are to assure that each use of the Code symbol (i.e., “V” or “E”) is in accordance with the requirements of Section I, the use of the symbol is documented and the document signed by the CI, and to verify that equipment to which a Code symbol is applied meets the requirements of Section I.

The third party inspector most familiar to those organizations authorized to use a Section I Code symbol is probably the Authorized Inspector. It is the function of the AI to assure and verify that the manufacturer complies with the Code. An Authorized Inspector is defined by Section I in PG-91 as an inspector employed by an ASME-accredited Authorized Inspection Agency (AIA). The AIA may be the inspection organization of a state or municipality of the United States, a Canadian province, or an insurance company authorized to write boiler and pressure vessel insurance. In the United States, it has been traditional that the Authorized Inspection Agencies providing authorized inspection for ASME Code symbol stamp holders are private insurance companies, but there is nothing preventing a state or municipality from providing authorized inspection as long as they are an ASME accredited AIA. At this writing, there are five states and 10 insurance companies accredited as AIA, which can provide authorized inspection in the United States. In Canada, there are eight provinces and one insurance company accredited as AIA. Until 1996, the provincial governments had provided all authorized inspection services through offices such as the department of labor. However, in an effort to cut the cost of government, two provinces (Alberta and Ontario) have privatized their authorized inspection activities by spinning them off into self-sustaining private companies. The Alberta organization is called the Alberta Boilers Safety Association (ABSA), and the Ontario organization is called the Technical Standards and Safety Authority (TSSA). The Canadian government passed a bill allowing the delegation of authority over this public safety program, formerly vested in the provincial governments, to not-for-profit non-governmental organizations. The new organizations are Crown Corporations, the administrators of which are dual employees of the jurisdiction and the newly privatized corporations. The National Board of Boiler and Pressure Vessel Inspectors has accepted the new corporations as representing the jurisdictions, and the chief inspectors of the new corporations are National Board members, as they were before the change. Other provinces may follow the example set by Alberta and Ontario. As Code construction becomes increasingly an international activity, the National Board intends to recognize and accept other foreign jurisdictions and their inspection agencies, as suitable arrangements (i.e., ASME accreditation) are devised.

The Authorized Inspector must be qualified by written examination under the rules of any state of the United States or province of Canada that has adopted the Code. When an Inspector is so qualified, he or she may obtain a commission, or certificate of competency, from the jurisdiction where the exam was given. The National Board of Boiler and Pressure Vessel Inspectors (the National Board) also grants commissions to those who meet certain qualifications and pass a National Board examination.

As a condition of obtaining from ASME a Certificate of Authorization to use an ASME Code symbol stamp, each Section I manufacturer or assembler must have in force a contract with an Authorized Inspection Agency spelling out the mutual responsibilities of the manufacturer or assembler and the Authorized Inspector. The manufacturer or assembler is required to arrange for the Authorized Inspector to perform the inspections called for by Section I. Paraphrasing the words of A-300 (the Quality Control System): the manufacturer shall provide the Authorized Inspector access to all drawings, calculations, specifications, process sheets, repair procedures, records, test results, and any other documents necessary for the Inspector to perform his or her duties in accordance with Section I. Section I lists many duties of the Authorized Inspector, all of which are intended to assure Code compliance. In 1997, BPV I approved the expansion of PG-90 on Inspection and Tests to include a comprehensive list of the AI's duties and references to the paragraphs where those duties are further described. The revised PG-90 appeared in the 1998 Addenda. However, even when Section I does not specifically describe the duties of an AI with respect to some provision of the Code, it is understood that the AI has very broad latitude in carrying out the mandate to verify compliance by the Code symbol stamp holder with all applicable Code rules.

It may be recalled from the discussion of the Preamble that "the Code does not contain rules to cover all details of design and construction," and that when complete details are not given, the manufacturer must provide details of design and construction as safe as those the Code does provide in its rules, subject to the acceptance of the Authorized Inspector. An AI may have sufficient experience to make a decision in such a situation, in which case, approval may be a simple matter. At other times, because of new or unusual construction, the AI may seek guidance from higher authority within his or her organization (many Authorized Inspection Agencies maintain an engineering staff), or via an inquiry to the Code committee to determine whether the proposed construction is acceptable.

If a symbol stamp holder violates the Code, the AI has several powerful remedies. The Authorized Inspector can require rework, additional NDE, or simply refuse to accept the boiler (or other component). Without the AI's signature on the Data Report Form, the boiler is not complete and cannot be sold or used where the Code is enforced. For repeated violations, the AI might also recommend that the contract for Authorized Inspection not be renewed. Finally, if the violations were flagrant, the matter could be brought to the attention of the Board on Hearings and Appeals. That Board would then conduct a hearing that could lead to the revocation of the offender's Certificate of Authorization to use a Code symbol stamp. Since the manufacturer needs its stamp to stay in business, third-party inspection provides a very effective means of assuring Code compliance.

The system devised by the ASME for establishing authority, assigning duties and assuring uniform examination of the third party inspectors has provided confidence that organizations authorized to use Code symbols have been consistent in application of Code rules. This confidence has proven essential to efficient commerce between jurisdictions as well as providing for the general welfare.

CERTIFICATION BY DATA REPORTS AND STAMPING

CERTIFICATION AND ITS SIGNIFICANCE

In order for the Code to be effective, there must be some means of assuring that it has been followed. Each phase of the work of designing, manufacturing, and assembling the boiler or component to which the ASME Code symbol is applied must be done in accordance with the Code (see Chapter 8, Third Party Inspection, regarding CSP-53, Protection of The ASME Mark). Assurance that a boiler is constructed to the Code is provided, in part, by a process called Code certification. In the simplest case of a complete boiler unit made by a single manufacturer, the manufacturer must certify on a form called a Manufacturer's Data Report Form that all work done by the manufacturer or others responsible to the manufacturer complies with all requirements of the Code. When some portion is performed by others not responsible to the manufacturer, the manufacturer must obtain the other organization's Code certification. In addition, the manufacturer must stamp the boiler with a Code symbol, which signifies that it has been constructed in accordance with the Code. Certification thus is an integral part of a quality assurance program which establishes that:

1. The organization that did the work held an appropriate ASME Certificate of Authorization to use a Code symbol;
2. The organization has certified compliance with the Code rules by signing and furnishing the appropriate Manufacturer's Data Report Form;
3. The organization has applied the Code symbol stamp to identify the work covered by its Data Report Form;
4. An Authorized Inspector or Certified Individual has confirmed by signing the Data Report Form that, to the best of his or her knowledge, the work complied with the applicable Code rules.

In the case of a complete boiler unit that is not manufactured and assembled by a single manufacturer, the same principles are followed. There is always one manufacturer who must take the overall responsibility for assuring through proper Code certification that all the work complies with the requirements of the Code. If, for example, the manufacturer of a boiler buys the drum (or any other part) of the boiler from another manufacturer, that other manufacturer must follow similar certification and stamping procedures. The part manufacturer must have a Certificate of Authorization to use the appropriate Code symbol, must certify compliance with all the Code rules on a Manufacturer's Data Report Form, must stamp the part, and an Authorized Inspector must sign the form as confirmation that the work complied with the applicable Code rules.

That form becomes part of the complete documentation assembled by the manufacturer of record. In general, the manufacturer of record has the duty of obtaining from all organizations that have done any Code work on the boiler their proper Code certification.

The same approach is used to certify that portion of the work called field assembly, for those boilers that are too large to be completely assembled in the shop. The Manufacturer's Data Report form typically has a certification box for use by the assembler of a boiler.

MANUFACTURER'S DATA REPORT AND CERTIFICATE OF CONFORMANCE FORMS

Section I has 11 different Manufacturer's Data Report Forms [MDR] and two Certificates of Conformance that have evolved over the years to cover various types of boilers and related components. These forms serve several purposes. First, they provide a documented summary of certain important information about the boiler or component: its manufacturer, purchaser, location, capacity, set pressure, and identification numbers. Most forms also provide a concise summary of the construction details used: a list of the various components (drum, heads, headers, tubes, nozzles, openings), their material, size, thickness, type, etc., and other information such as the design and hydrostatic test pressures and maximum designed steaming capacity.

The MDR and their use are described in PG-112 and PG-113, and in Appendix A-350, which contains examples of all the forms and a guide for completing each one. Also in the Appendix is a Guide to Data Report Forms Distribution (A-357). This guide explains which forms should be used in ten different circumstances involving several types of boilers that may be designed, manufactured, and assembled by different stamp holders. The Certificates of Conformance and their use are described in PG-73.7 and in Mandatory Appendix III, Criteria for Reapplication of An ASME Code Symbol Stamp. There are so many forms and combinations of forms that can be used that the subject can often be quite confusing. What is important to remember is the purpose of the forms: to provide a summary of essential information about the parts comprising the boiler and to provide for certification as appropriate by all those involved (the various manufacturers and inspectors) that all components of the boiler were constructed to the rules of Section I. At the same time, it is also important to understand that the MDR were never intended to be an all-inclusive catalog or parts list for the boiler or component, nor a substitute for the manufacturer's drawings. If more information is needed than is found on the forms, it can be found on those drawings.

Certain of the forms are sometimes called Master Data Report Forms. A Master Data Report Form, as the name implies, is the lead document when several different forms are used in combination to document the boiler. The P-2, P-2A, P-3, and P-3A forms can be used as Master Data Report Forms. The other forms (the P-2B, P-4, P-4A, P-4B, P-5, P-6, P-7, and P-8) usually supplement the information on the Master Data Report Forms and are attached to them.

Before explaining how the forms are completed, it is helpful to list and describe them.

THE SECTION I MANUFACTURER'S DATA REPORT AND CERTIFICATE OF CONFORMANCE FORMS

1. Form P-2, Manufacturer's Data Report Form for All Types of Boilers Except Watertube and Electric

This form was designed primarily for firetube boilers.

2. Form P-2A, Manufacturer's Data Report Form for All Types of Electric Boilers

This form was specifically designed for electric boilers, when Part PEB, dealing with such boilers, was added to Section I in 1976.

3. Form P-2B, Manufacturer's Data Report for Electric Superheaters and Reheaters

Added in the 2004 Addenda, this form was designed specifically for electric superheaters and reheaters installed external to the boiler setting.

4. Form P-3, Manufacturer's Data Report Form for Watertube Boilers, Superheaters, Waterwalls, and Economizers

This form can be used to document a complete boiler or major subcomponents. Both the P-3 and P-4 forms contain a table identified as line 12, which has a column for listing heating surface of various components. Some advice is given next to the table, noting that total boiler and waterwall heating surface is to be stamped on the drum heads and that any other heating surface is not to be used for determining minimum pressure relief valve relieving capacity. The details of this heating surface calculation are explained in PG-101. That paragraph is a vestige of former rules for calculating the required pressure relief valve relieving capacity for certain types of boilers from the type and area of heating surface in the boiler. However, since a significant revision to the pressure relief valve requirements appeared in the 1993 Addenda, heating surface is seldom used to determine minimum required pressure relief valve capacity. See further discussion under safety valves.

5. Form P-3A, Engineering-Contractor Data Report Form for a Complete Boiler Unit

This form differs significantly from those listed above. It is used when an engineering-contractor organization assumes the Code responsibility for the boiler normally taken by a boiler manufacturer. Since the engineering-contractor has no manufacturing facilities, all parts comprising the boiler are purchased from other Code symbol stamp holders, who are manufacturers. They furnish the necessary documentation for those parts, using other MDR such as the P-4 or P-4A, which the engineering-contractor attaches to the P-3A. The P-3A form requires the engineering-contractor to provide a design specification for the boiler, that is, a list of components giving the design pressure and temperature of each.

6. Form P-4, Manufacturer's Partial Data Report Form

This form gets its name from the fact that it covers only an individual component part of the boiler such as a drum or header. In general, this is not a stand-alone form; it merely provides supplementary data for the information shown on another form, the so-called Master Data Report Form, to which it is attached. However, it is a stand-alone form when used to document replacement parts for an existing boiler, as explained in PG-112.2.4.

One of the weaknesses of the P-4 form used to be that it never made clear who was taking design responsibility for the parts being documented. The resolution of this issue was not as simple as it might first appear because sometimes a parts manufacturer may design the part, while at other times, the manufacturer may just fabricate the part in accordance with a drawing he was given (a common practice called "build to print"). After considerable discussion and study by the committee, the problem of design responsibility for parts was addressed by the addition of a new paragraph, PG-112.2.4(c), in the 1996 Addenda. That paragraph calls for the parts manufacturer to indicate on the "remarks" line of the form the extent to which it has performed the design function.

7. Form P-4A, Manufacturer's Data Report for Fabricated Piping

PG-112.2.5 explains that this form is used to record all shop or field-welded piping that is within the scope of Section 1 but that is not furnished by the boiler manufacturer. (When the boiler manufacturer furnishes such piping, it can be included on the manufacturer's own Data Report Form without the P-4A.) Note that PG-109.2 relaxes the stamping and marking requirements for welded piping that is NPS 2 (DN 50) and smaller. It need not be stamped, nor listed on the data report. However, it must be traceable to the data report.

Like the P-4 form just described, the P-4A form is also not definitive regarding who has design responsibility for the piping, mostly because of the nature of the "PP" stamp holder's business, which often involves fabrication of piping specified or designed by someone else (build to print). The P-4A form has three entries that concern design on its line 5. The entries are:

1. Design conditions (pressure and temperature);
2. The name of the organization that specified the design conditions; and
3. The name of the organization that did what is described as Code Design.

There is no certification box or any other place on the form where any organization actually assumes Code design responsibility by explicitly certifying that the design of the piping meets the rules of Section I. Unless the organization whose name appears in the space marked “Code Design by” has an appropriate Code symbol stamp (“S” or “PP”), it seems the responsibility would fall by default on the “PP” stamp holder who fabricates the piping.

8. Form P-4B, Manufacturer’s Data Report for Field Installed Mechanically Assembled Piping

As explained at the end of Chapter 7 under Hydrostatic Test of Mechanically Assembled Piping, the 1998 Addenda to Section I established new rules for this type of piping in PG-99, PG-104.1, PG-109.4, and PG-112.2.5. The new rules provide that mechanically assembled piping need not be assembled by a Code symbol holder, but that responsibility for its documentation and hydrostatic testing must be assumed by the holder of an “S”, “A”, or “PP” stamp. This would include a hydrostatic test witnessed by an Authorized Inspector. Documentation of the piping requires the use of a new form, the P-4B form. This form resembles the P-4A form, but differs from the latter in the certification required. The stamp holder must certify only that the field assembly of the described piping conforms to the requirements of Section I. There is no certification of shop or field fabrication compliance.

9. Form P-5, Summary Data Report for Process Steam Generators

This form was devised to cover process steam generators of the waste heat or heat recovery type. These are usually field-assembled arrangements of one or more drums, arrays of heat exchange surface, and associated piping.

All components must be certified by their manufacturers on individual Data Report Forms. The organization having Code responsibility for the complete system (the manufacturer or engineering-contractor of record) must collect all Data Report Forms for components comprising the boiler. The manufacturer or engineering-contractor is permitted to use the P-5 form to list all the Data Report Forms associated with the completed boiler, thus “summarizing” the required certification documents.

10. Form P-6, Manufacturer’s Data Report Supplementary Sheet

This form is used to record additional data when space is insufficient on any other Data Report Form. Many boilers, large utility boilers especially, cannot be documented on a single page; some take 50 pages or more. It is common to use supplementary sheets with whatever format or arrangement best suits the circumstances.

11. Form P-7, Manufacturer’s Data Report for Pressure Relief Valves

This form was added to Section I by the 1996 Addenda in response to concerns that changes to pressure relief valve set pressure on existing boilers might subject piping to pressure for which it was not designed. Although this is a postconstruction issue usually considered beyond Section I’s concerns, the committee felt that a summary listing of all pressure relief valves, their location, set pressure, and relieving capacity would be useful to the Authorized Inspector during construction of the boiler and, perhaps, subsequently. It provides the Authorized Inspector a summary of the valve-relieving capacities, which the Inspector can use to help verify that the required relieving capacity has been supplied.

12. Form P-8, Manufacturer’s or Assembler’s Certificate of Conformance for Pressure Relief Valves

This form was added to Section I in the 2003 Addenda as part of an action to implement CSP-53, Policy on Protection of ASME Marks (see Chapter 8 for a brief summary of the policy). The form provides a means of documenting certain data relating to Section I pressure relief valves such as identification number, type, size, capacity, etc. It also provides a means to satisfy the requirement that use of the ASME mark (i.e., the “V” symbol) is documented and the document signed by a third party inspector, in this case a Certified Individual.

13. Form III-1A, Certificate of Conformance for Replacement of the ASME Code Symbol Stamp

Added in the 2009 Addenda, the use of the form is described in Mandatory Appendix III, Criteria For Re-application of An ASME Code Symbol Stamp. While reapplication of a Code symbol stamp is not common, it does occur when the stamping becomes indistinct, or the nameplate is illegible or lost. The appendix and the form provide rules for reapplication of the Code symbol and a means to document the reapplication. Like Form P-8, above, the appendix and form were included in the Code to help assure protection of an ASME mark as required by CSP-53.

COMPLETING THE MANUFACTURER'S DATA REPORT FORMS

These forms typically provide a place for the manufacturer to certify that the design, material, construction and workmanship conform to Section I. In so certifying, the manufacturer must also identify which Code symbol it is using, and the number and expiration date of its Certificate of Authorization to use it.

Also provided on these forms are other certification boxes, or certificates of compliance, covering shop inspection, field assembly, and field assembly inspection. Some of these boxes, such as field assembly, may not be applicable and would be left blank.

Except as provided in PEB-18.5, which allows third party inspection by a Certified Individual, the certificate of shop inspection is completed and signed by the Authorized Inspector who has inspected the shop fabrication of the boiler or other components. The AI provides information about the AI's employer, commission held, parts of the boiler inspected, and documentation examined for parts not inspected. The AI then, by his or her signature, certifies that, to the best of his or her knowledge and belief, the manufacturer of the boiler has constructed it in accordance with Section I.

Many boilers are not completed in the shop because of their size or for other reasons. In such cases, the various components are assembled in the field. The field assembly is, in most cases, a Code activity performed by a single organization holding an appropriate Code symbol (either an "A" or an "S"). This organization must complete a box certifying that the field assembly of the boiler conforms to the requirements of Section I and provide particulars about its Certificate of Authorization. In response to a situation in which one organization started the field assembly of the boiler, but was replaced by another that completed the assembly, BPV I developed rules to provide for assembly of a boiler by more than one organization. These rules are found in PG-107.2 and were included in the 2004 Edition of Section I. The rules described the process for handling the description and Code certification of work performed by each organization.

The field assembly of the boiler is subject to inspection by the assembler's AI, who also completes a certification box giving information about his or her employer, the commission the AI holds, and which parts of the boiler the AI has inspected. The AI must also have witnessed the hydrostatic test of the boiler. The Inspector then signs and dates the form, stating that to the best of his or her knowledge and belief, the manufacturer and/or the assembler has constructed and assembled the boiler in accordance with Section I.

DISTRIBUTION OF THE DATA REPORT FORMS

When the Manufacturer's Data Report Forms are complete, Section I requires copies to be furnished to the purchaser, the inspection agency, and the municipal, state, or provincial authority at the place of installation. In addition, many jurisdictions require registration of the boiler with the National Board, which would then be sent copies of the Manufacturer's Data Report. Many boiler manufacturers routinely register all their boilers with the National Board. Thus, the concerned organizations have available a valuable summary of the design data and the technical details of the boiler. This can be very helpful many years later for investigations, repairs, or alterations, when original plans may have disappeared or are not readily available. Surprisingly, this is often the case. Having such information as the applicable Code Edition and the details of original components can facilitate any subsequent work on the boiler. The designer then knows the design pressure,

the size, thickness, material, allowable stress, and design formulas originally used and can make appropriate choices for repair, replacement, or alteration. Copies of Data Report Forms on file with the National Board can be readily obtained from that organization, and this is a major benefit of National Board registration (a service available for both boilers and pressure vessels).

INTERPRETATIONS ON USE OF MANUFACTURER'S DATA REPORT FORMS

Although the use of computer-generated data report forms is becoming more and more common, there was a time when only the official forms obtained from the ASME or the National Board were deemed acceptable. However, in 1989, Interpretation I-89-27, Use of Computer-Generated Manufacturer's Data Report Forms, established that other forms were acceptable:

Question: Does Section I allow creation of Manufacturer's Data Report Forms by a Code symbol stamp holder using any printed or computer-generated forms, provided the size, arrangement, and content are identical, without addition or deletion, to the Data Report Forms in the latest Edition and Addenda of Section I?

Reply: Yes.

As mentioned earlier, there are so many data report forms, and so many different situations in which they might be applied, that occasionally disputes arise as to how the parts are to be documented. BPV I has shown some flexibility in the use of two different forms for pipe and pipe-like components. Either the P-4 Partial Data Report Form (intended for parts) or the P-4A (intended for piping) may be used. This was affirmed in Interpretation I-92-30, Manufacturer's Data Reports for Boiler Proper Piping and Boiler External Piping:

Question: May fabricated boiler proper piping constructed only by welding as covered by PW-41 and fabricated by a manufacturer or a contractor in possession of the pressure piping symbol stamp be reported on a Manufacturer's Data Report Form P-4A as called for in PG-112.2.5?

Reply: Yes; alternatively, a Form P-4 may be used. See PG-109.3.

A similar Interpretation, I-92-46, Stamping of Boiler Proper Piping, affirmed that certain components can be stamped either as parts or as piping. This interpretation may be found at the end of the following section on Code Symbol Stamps.

Other inquiries have dealt with the question of which piping must be documented on the data report forms because Section I is not explicit on the subject. One of these was Interpretation I-80-18, External Piping:

Question: Do the rules of Section I, PG-104, require that boiler external piping within the scope of Section I and supplied by the boiler manufacturer, be specifically documented on the P-3 Data Report?

Reply: No. The ASME P-3 Data Report Form contains (in item 11) spaces to record the number, size, and type of nozzle outlet for four categories of connection to the boiler. These are:

- (1) steam*
- (2) safety valve*
- (3) blowoff*
- (4) feed*

Guidelines No. 21, 22, and 23 in A-352 amplify this to explain what information is to be recorded. The explanation includes a statement that small openings for water columns, controls, vents, drains, and instrumentation, or openings for connections within the boiler proper, such as risers and downcomers, are not intended to be included in this listing.

The P-3 Form does not contain any spaces or requirements for recording any other information, such as piping arrangements, length, thickness, or material specifications for boiler

external piping in any category. The manufacturer who supplies the boiler external piping has the responsibility to comply with applicable rules (including both ASME Section I for certification and ANSI B31.1 for technical requirements). The Authorized Inspector has the duty to verify the manufacturer's compliance. Neither the manufacturer nor the Authorized Inspector has an obligation to use the P-3 Form as a record of Code compliance of their respective work on boiler external piping.

What the above interpretation affirms is that when the manufacturer of the boiler also furnishes the boiler external piping, the manufacturer need not document it in detail on the P-3 form. The reason is believed to be that in such cases the boiler manufacturer has the full responsibility for every part of the boiler, and that manufacturer's drawings will provide for all piping. However, when another manufacturer furnishes the external piping, it is necessary to have that piping documented in greater detail, on the P-4A form.

Another Interpretation advising about what piping had to be listed on a data report form was I-83-16, Form P-2A, Listing of Miscellaneous Piping:

Question: Is it a requirement of Section I that piping items other than steam, feedwater, and blowoff listed on Form P-2A, Item 16, be included when completing Forms P-2A or P-6?

Reply: No.

The section of this chapter describing the P-4 Form describes how the parts manufacturer is to document the extent to which it performed the design function (i.e., indicate the extent in the "remarks" section per PG-112.2.4(c)). As shown by the following interpretation, I-04-30, issued in August 2005, there remain questions regarding certification of design by the part manufacturers.

Question (1): For parts manufactured and certified under the provisions of PG-112.2.4(b) on Form P-4, does PG-112.2.4(c) prohibit the part Manufacturer from stating "no design functions performed" in the "Remarks" section of Form P-4?

Reply (1): No.

Question (2): If the reply to Question (1) is "No", is the part Manufacturer required to list a MAWP for parts certified on Form P-4?

Reply (2): No.

Question (3): If the reply to Questions (1) and (2) is "no", is the part Manufacturer required to identify the boiler in which the part is intended to be installed?

Reply (3): No.

CODE SYMBOL STAMPS AND HOW THEY ARE OBTAINED

The ASME committee that formulated the first Edition of the Code in 1915 recognized a need to identify in a unique way any boiler constructed to meet the Code. They decided to do this by having the manufacturer stamp the boiler with a Code symbol. Paragraph 332 of that original Edition stipulates, in part, "Each boiler shall conform in every detail to these Rules, and shall be distinctly stamped with the symbol shown in Fig. 19, denoting that the boiler was constructed in accordance therewith. Each boiler shall also be stamped by the builder with a serial number and with the builder's name either in full or abbreviated . . ." The official symbol for such a boiler was then, and is now, an S enclosed in a clover leaf. That symbol is evidence that the boiler complies with the Code and represents an assurance of safe design and construction. A great many provisions of Section I are directed to making sure that this will be so.

Over the years, Section I has added other symbol stamps, and there are now a total of six covering different aspects of boiler construction. These symbol stamps are:

"S"	power boiler	"A"	boiler assembly
"E"	electric boiler	"PP"	pressure piping
"M"	miniature boiler	"V"	pressure relief valve

Until the late 1970s, there was also an “L” stamp, used for locomotive boilers, but by that time there were only two manufacturers who were still authorized to use the “L” stamp. The committee decided to abolish what had become an obsolete stamp, and those last two manufacturers were given S stamps instead.

Except under certain carefully controlled circumstances, no organization may do Code work (e.g., fabricate or assemble any Section I boiler components) without having first received from the ASME a Certificate of Authorization to use one of the Code symbol stamps. Before an organization can obtain such a certificate, it must meet certain qualifications, among which are the following.

The organization (manufacturer, assembler, or engineering-contractor) wishing to obtain an “S”, “M”, “E”, “A” or “PP” Code symbol stamp must have in force at all times an agreement with an Authorized Inspection Agency (AIA — see Chapter 8). This agreement covers the terms and conditions of the authorized Code inspection to be provided and stipulates the mutual responsibilities of the manufacturer or assembler and an inspector provided by the inspection agency. These inspectors, called Authorized Inspectors, must be qualified by written examination under the rules of any state of the United States or province of Canada whose boiler laws have adopted Section I. Authorized Inspectors provide the inspection required by Section I during construction or assembly and, after completion, of any Section I component.

A further requirement for obtaining a Certificate of Authorization to use one of the ASME Code symbol stamps, including the “V” symbol stamp, is that the manufacturer or assembler must have, and demonstrate, a quality control system to establish that all Code requirements will be met. These pertain to material, design, fabrication, examination by the manufacturer or assembler, and inspection by the Authorized Inspector. An outline of the features required in the quality control system is provided in Appendix A-300 and is discussed in Chapter 10.

Finally, before the ASME issues (or renews) a Certificate of Authorization to use the “S”, “M”, “E”, “A”, or “PP” symbol, the manufacturer’s or assembler’s facilities and organization are reviewed by a team consisting of a representative of the inspection agency (AIA) and an individual certified as an ASME Designee who is selected by the legal jurisdiction involved. Before issuance or renewal of a Certificate of Authorization to use the “V” stamp, the manufacturer’s facilities must be reviewed by an ASME designee. The manufacturer or assembler must make available to the review team a written description of the quality control system that explains what documents and procedures will be used to produce or assemble a Code item. On recommendation of the review team, the ASME issues (or renews) a Certificate of Authorization to use a particular Code symbol stamp, normally for a period of 3 years.

Applicants for Certificates of Authorization may not have a clear understanding of just what capabilities they must have to obtain any particular stamp, since nowhere does Section I provide a complete and specific list of such capabilities. The prospective certificate holder is ordinarily guided in this regard by their Authorized Inspection Agency. Table 9.1 presents a simplified summary of the capabilities usually necessary to obtain the various stamps. Note that the Code has traditionally allowed certificate holders to subcontract almost every aspect of construction (such as nondestructive examination, postweld heat treatment, and even design) so long as the certificate holder retains and accepts responsibility for Code compliance of work done on their behalf. Further, the certificate holder’s quality control system would have to describe this option and the monitoring and controls used to assure compliance with Section I.

WHAT THE CODE SYMBOL STAMPS COVER

The “S” Stamp

The “S” stamp covers the design, manufacture, and assembly of power boilers. This stamp is applied to the completed boiler unit. It may also be applied to parts of a boiler, such as a drum, superheater, waterwall,

TABLE 9.1
CAPABILITIES NEEDED TO OBTAIN SECTION I CODE SYMBOL STAMPS
 (It is permissible to subcontract for certain of these capabilities. See text.)

CODE SYMBOL STAMP	DESIGN CAPABILITY	QUALIFIED WELDERS, BRAZERS AND PROCEDURES Note 1	NDE AVAILABLE Note 1	HEAT TREATMENT FACILITY AVAILABLE Note 1	Q.C. SYSTEM
"S" POWER BOILER	R	R	R	R	R
"A" BOILER ASSEMBLY	NR	R	R	R	R
"PP" POWER PIPING	R	R	R	R	R
"M" MINIATURE BOILER	R	R	NR	NR	R
"E" ELECTRIC BOILER	R	R	R	R	R
"V" PRESSURE RELIEF VALVE	R	R Note 2	R	R Note 2	R

LEGEND: R = REQUIRED

NR = NOT REQUIRED

Note 1: It is possible to manufacture certain small boilers without welded or brazed joints. In such cases, qualified welders and brazers, weld and brazing procedures, heat treatment facilities, and nondestructive examination would not be required.

Note 2: Not required for valves whose manufacture does not involve welding.

economizer, header, or boiler external piping. When some parts of a boiler are furnished by a certificate holder other than the manufacturer of the completed boiler, the manufacturer of such parts may use its own "S" symbol stamp plus the word "part" to identify them. Other parts of a boiler such as valves, fittings, and circulating pumps do not require inspection, stamping, and certification when furnished as standard pressure parts under the provisions of PG-11, as explained in Chapter 11.

A manufacturer may assume Code responsibility for a miniature or electric boiler using the "S" stamp as a substitute for the "M" or "E" stamps. (Stated another way, an "S" stamp may be used for miniature or electric boilers.)

The "S" stamp may also be used to cover field assembly of a boiler and/or boiler external piping. However, if the boiler or piping was furnished by others and the "S" stamp holder was merely acting as an assembler of the boiler and piping, the assembly work would be more likely to be done under the authority of an "A" certificate (see the "A" stamp, below), so as to avoid confusion as to which organization was the manufacturer of record and which was the assembler.

The "S" stamp can also be issued to entities called engineering-contractor organizations, mentioned in PG-104, Note 1. These are organizations that may not have manufacturing facilities but do have boiler design capability and sometimes field-assembly capability. The work this type of organization may do is discussed below with interpretations on Code symbol stamping, at Interpretation I-92-12.

BPV I has always considered the "S" stamp the senior stamp among all the rest, which in theory at least allows the holder to engage in any type of Section I construction: design, manufacture, or assembly, so long as the holder's quality control system covers that activity.

The “M” Stamp

The “M” stamp is applied only to miniature boilers: that is, to boilers that do not exceed the limits specified in PMB-2 of Section I. Should the boiler exceed any of those limitations, the manufacturer must apply either the “E” or “S” symbol as appropriate.

The “E” Stamp

The “E” stamp is applied to certain electric boilers of the electrode or immersion resistance element type. In most cases, that manufacturer mechanically connects the necessary trim, fixtures, and fittings to a boiler pressure vessel furnished and Code stamped by others with the “S”, “M”, or “U” stamp (in the latter case, subject to the vessel requirements of PEB-3). For some manufacturers, the heating element is attached using a brazed joint connection. The manufacturer then applies the “E” stamp to the completed assembly and becomes the manufacturer responsible for the completed boiler.

The “A” Stamp

The “A” stamp covers the field assembly of a boiler when done by someone other than the manufacturer of the boiler. In such a case, the assembler shares Code responsibility for the completed boiler jointly with the boiler manufacturer, and the assembler’s “A” stamp must supplement the manufacturer’s stamp. (See PG-107.2 and PG-108.2.) The “A” stamp may also be applied for the assembly of boiler external piping.

Note that the “A” stamp does not cover manufacture of a boiler or parts of a boiler; it covers only assembly of Code-stamped parts or Code material provided by others. The “A” stamp holder is not authorized to take Code design responsibility.

The “PP” Stamp

The primary application of the “PP” stamp is to the fabrication of boiler external piping and to its installation by welding when the piping is not furnished by the boiler manufacturer. In the 2005 Addenda, the Code was revised to allow the “PP” symbol to also be applied to fabrication of boiler parts such as superheater, waterwall, or economizer headers, provided the complete design requirements are provided by others (see discussion under Interpretations on Code Symbol Stamping, below).

The question has yet to be raised formally, but Section I does not provide any guidance as to what, if any, authorization or qualification the designer of the component must have under this circumstance.

The “V” Stamp

The “V” stamp may be applied by manufacturers or assemblers of pressure relief valves for power boilers to show that the parts and assembly of the valves comply with Section I requirements, including capacity certification. For further discussion, see Chapter 12, Pressure Relief Valve Requirements.

REAPPLICATION OF AN ASME CODE SYMBOL STAMP

The policy regarding protection of the ASME marks (CSP-53, See Chapter 8) has been mentioned a number of times. Mandatory Appendix III, Criteria for Reapplication of An ASME Code Symbol stamp, was developed in response to that policy and included in the 2009 Addenda of Section I. On occasion, the Code

symbol stamping or nameplate on a boiler become illegible or lost, and the owner, at times at the request of the governing jurisdiction, wishes to reapply the Code symbol. Until Appendix III was issued, re-stamping of a boiler or pressure vessel was done in accordance with rules established by the National Board. The ASME decided that it was inappropriate for another organization to control the use of its marks and, thus, the issuance of the appendix. As the title implies, Appendix III provides rules governing the process of reapplying a Code symbol, including documentation. Reapplication of the Code symbol may only be done to provide evidence of the original compliance to Section I requirements and may not be used to certify the current condition of a boiler.

INTERPRETATIONS ON CODE SYMBOL STAMPING

There have been many Interpretations on the use of Code symbol stamps that clarify what the rules permit and prohibit. Since the stamping rules cover so many situations, it is helpful to review some of the important interpretations on the subject. One of these, I-01-17, Fabrication of Parts by a “PP” Stamp holder, was issued in March 2002 and led to the 2005 revision of PG-109.3 (see The “PP” Stamp, above). As explained during consideration of the proposed revision by BPV I, the historical role of the “PP” stamp holder has been fabrication of boiler external piping and of parts involving circumferential joints in pipe, tubes and headers. Interpretation I-01-17 highlighted that PG-109.3 does not limit the “PP” stamp holder’s scope of design activities. It read:

Question: Does PG-109.3 prohibit a “PP” stamp holder from fabricating parts of boilers such as superheater, waterwall, or economizer headers that include flat covers in accordance with PG-31?

Reply: No.

Concerns were expressed that permitting a “PP” stamp holder to design parts of a boiler may go beyond the expertise typically required for piping. As a result, PG-109.3 was revised to clarify that while the component may be fabricated by a “PP” stamp holder, complete design of the component must be by others.

Another, I-78-24, Stamping of Boiler External Piping for Boiler Installations, explains some basic principles and applications of the stamping and certification process:

Question: What is the definition of boiler unit as used in PG-104?

Reply: Boiler unit refers to everything within the scope of the jurisdiction of Section I; this comprises the boiler proper plus the boiler external piping (Preamble, third paragraph).

Question: Does the boiler manufacturer use his S symbol stamp to “cover” the entire boiler unit?

Reply: Yes, but only in the sense explained in PG-104. If some portions are supplied by, or Code work is done by, others not responsible to the boiler manufacturer, these other organizations must hold proper Certificates of Authorization and furnish their certification and stamping to supplement the boiler manufacturer’s certification.

For example, if some or all of the boiler external piping is supplied by a fabricator other than the boiler manufacturer, such piping should be “covered” by that fabricator’s S or PP stamp and documented with the P-4A Form. (See PG-109.)

If the field assembly is by other than the boiler manufacturer, provisions of PG-107.1 require use of the assembler’s A symbol to supplement the manufacturer’s S symbol, and the assembler is identified on the field assembly block of the data form.

Question: Does the stamping referred to in ANSI B31.1 for boiler external piping differ from that of ASME Section I?

Reply: No, B31.1 refers to Section I for all certification (data reports, inspection, and stamping) to cover boiler external piping.

Question: *In the context of the Preamble of Section I, is boiler external piping considered a “pressure part”?*

Reply: *The fourth paragraph of the Section I Preamble begins, “Superheaters, economizers, and other pressure parts connected directly to the boiler without intervening valves shall be considered part of the boiler proper . . .” Boiler external piping is not an “other pressure part” as used in that phrase, even though any piping is considered a pressure part in Code usage. Figures PG-58.3.1 and PG-58.3.2 attempt to illustrate the commonly encountered division points between “boiler proper” and “boiler external piping.”*

Another lengthy Interpretation that illustrates which stamps may be used by different organizations involved in manufacture and assembly of boiler components and also affirms the “S” stamp as the senior stamp is I-81-22, Clarification of Limits of Certificates of Authorization:

Question: *In PG-109.1, installation of boiler external piping fabricated by anyone other than the boiler manufacturer is allowed by a manufacturer or contractor in possession of a Certificate of Authorization for an S stamp, A stamp, or PP stamp.*

(a) *Under what conditions does PG-109.1 permit the use of the A stamp?*

(b) *When the boiler external piping is to be installed, but not fabricated by the contractor, may the S stamp still be used or must the contractor have a PP stamp?*

(c) *May a contractor who did not design the boiler unit use his S stamp for assembly? Can he also use his S stamp for assembly of boiler external piping?*

Reply for (a): *PG-109.1 permits a manufacturer in possession of a Certificate of Authorization for use of the A stamp to install boiler external piping, by welding, in accordance with the applicable rules of ANSI/ASME B31.1, Power Piping.*

Reply for (b): *The holder of an S stamp may use that stamp to install boiler external piping by welding.*

Reply for (c): *Yes to both questions.*

Question: *Are the terms “manufacturer and fabricator” as used in PG-104 and PG-109.1 synonymous with respect to the S stamp?*

Reply: *The term “fabricator” is not used in PG-104 and PG-109.1. Note I of PG-104 mentions “fabricating facilities,” and “fabricated by anyone other than the manufacturer of the boiler.”*

(Note: This answer dodged the question. For practical purposes, the two terms are synonymous in this context.)

Question: *May a holder of an S stamp, who is not the manufacturer (PG-104) of the boiler, use that S stamp to cover assembly work during construction of a complete boiler unit?*

Reply: *Yes.*

Question: *Does Note 2 of PG-104.1 pertain only to shop-assembled boilers as indicated in PG-107?*

Reply: *No. Note 2 of PG-104.1 applies to all boiler external piping within the scope of Section I, whether the boiler is field assembled or shop assembled, when the boiler manufacturer does not furnish that piping.*

Question: *What is the definition of a shop-assembled boiler?*

Reply: *A shop-assembled boiler is one for which the manufacture of the boiler, with or without the boiler external piping, is completed in the boiler manufacturer’s shop.*

Question: *Is it a mandatory requirement that any contractor who may have occasion to work on a Code boiler be required to have a stamp in order to perform the necessary work even though the welders are qualified to Section IX? If this is not a Code requirement, would it be a jurisdiction or National Board requirement?*

Reply: *If the inquiry pertains to new construction, any work that falls within the scope of the Code must be performed by an organization holding an appropriate Certificate of Authoriza-*

tion. Rules governing work on boilers after they have been placed in service vary, depending on the requirements, if any, adopted by the administrative authorities of the state, municipality, or province where the boiler is installed.

It happens that the reply to the above question of what is a shop-assembled boiler raises a question of just what completion of the boiler can mean, depending on whether the boiler is field assembled or shop assembled. A field-assembled boiler is considered complete after the boiler external piping is installed, and the boiler has passed the hydrostatic test. However, for various reasons, smaller, shop-assembled boilers, especially those with threaded piping, are often not provided with boiler external piping installed in the shop. This situation sometimes arises because with the piping attached, the boiler would be too large to ship, or because purchasers have traditionally furnished their own piping, or perhaps because the boiler is being built for stock, in anticipation of future sale to a customer whose external piping requirements are not yet known.

When threaded boiler external piping is involved, it is often the custom to subject the boiler proper, either with no external piping attached or perhaps with some minimal piping and valves installed to a hydrostatic test. The data report forms are then completed and signed, and the boiler is considered complete. Any further completion and installation of the boiler external piping is done by others, perhaps a plumber, in the field. This practice has been followed for a long time in many jurisdictions and is supported by the words of PG-104.1, Note 2, which in effect waive Code certification and data report forms covering piping that is not welded. However, at present, Indiana and Iowa insist on a more formal and comprehensive completion of a boiler with threaded piping. They insist on a hydrostatic test in the field in the presence of an Authorized Inspector and certification of the piping. As explained in Chapter 7, under Hydrostatic Test of Mechanically Assembled Boiler External Piping, BPV I in 1997 resolved a number of conflicting issues associated with what is called “piping installed by mechanical means” (threaded or bolted piping) by revising PG-109.4 and providing a new Form P-4B.

The situation differs when the boiler external piping is welded. When welded external piping is furnished by a stamp holder other than the boiler manufacturer, Note 2 stipulates that the organization that furnishes and installs it is responsible for proper Code certification in the form of stamping, and Data Report P-4A. That same organization is also responsible for distributing copies of Form P-4A to the inspection agency and the proper authorities, as noted in PG-113.4

Interpretation I-83-56, Use of “S” Symbol for Fabrication of BEP, affirms that an “S” stamp holder who is not the manufacturer of the boiler may fabricate boiler external piping in his shop and stamp it with the “S” symbol.

It is sometimes difficult to draw a clear distinction between the activities that constitute manufacturing piping and those that constitute assembly of the piping. Both activities could involve cutting, bending, and preparing pipe for welding, and then welding lengths of pipe together. This has led to some confusion as to whether the “A” stamp holder could manufacture, or fabricate, welded piping. The key difference is that an assembler may not take design responsibility, one of the capabilities a fabricator must have if he is to obtain an “S” or “PP” stamp, since the fabricator is often expected to take design responsibility for that piping. The committee addressed this misapprehension twice, in Interpretation I-80-17, Certificates of Authorization, and in I-83-68, Fabrication of Pressure Piping Using an “A” Symbol Stamp. Here are those Interpretations:

Question: May an A stamp holder, whose quality control system covers all Code mandated requirements for shop fabrication of pressure piping, fabricate such piping and provide Code certification of it, using his A stamp authorization?

Reply: No. If an applicant has a quality control system which covers all Code mandated requirements for shop fabrication of pressure piping, and can show implementation of this system, the applicant is eligible for the PP stamp authorization, and should obtain it if he wishes to manufacture such piping components. The same organization may or may not be an A stamp holder.

Question: May an organization in possession of an A Code Symbol Stamp fabricate welded pressure piping described in PG-109.1 or parts of boilers described in PG-109.3?

Reply: No. An A stamp holder may only assemble such piping or parts by welding; an S or a PP stamp is required for their fabrication.

As mentioned above in the discussion of Certificates of Authorization, a stamp holder may subcontract many of the activities for which he is ultimately responsible. These could include such activities as nondestructive examination, postweld heat treatment, bending operations, and cutting and threading of pipe. The key requirements for subcontracting such activities are control by the stamp holder's quality system and the avoidance of welding, which is an activity normally requiring the use of qualified welders using qualified welding procedures under the direct supervision of the stamp holder. One Interpretation dealing with such subcontracting is I-86-38, somewhat misnamed as Definition of Joined by Mechanical Means:

Question: When piping within the scope of Section I is being installed by a Certificate holder, is it permissible for a subcontractor who is not in possession of a Code symbol stamp to perform such functions as cutting and threading of pipe?

Reply: Yes; however, responsibility must be accepted by the Certificate Holder.

Another Interpretation dealing with such subcontracting is I-95-17, Pipe Bending by Organization Not Authorized to Use a Code Symbol Stamp:

Question: May an organization holding an S or a PP stamp subcontract the bending of pipe to an organization without a Code symbol stamp, provided the bending operations involve no welding and the stamp holder's quality control system covers the subcontracted activity?

Reply: Yes.

A similar Interpretation dealt with threading and machining of piping, which may also be done by an organization without a Code symbol stamp. This was Interpretation I-92-04, Code Stamping of Pressure Piping:

Question: Is Code stamping required prior to shipment on piping which has undergone bending, threading, or machining, (but not welding)?

Reply: No.

Another example extends the principle of subcontracting to include even design calculations. This was affirmed by Interpretation I-92-48, Code Responsibility for Design Calculations:

Question: May a manufacturer certify that engineering and design calculations performed by others, not holding a Certificate of Authorization, but under contract to the manufacturer, comply with all the requirements of the Code?

Reply: Yes.

Interpretation I-86-13 stated this principle in another way:

Question: Boiler external piping as defined in PG-58 is fabricated and installed by separate organizations holding appropriate Certificates of Authorization in accordance with paragraphs PG-104, PG-109, and PG-112. Is the organization that prepares the purchase specifications and/or performs the Code design of the piping as identified on line 4 of the Form P-4A required to be the holder of a valid Certificate of Authorization?

Reply: No.

Note that under the circumstances just described, one, or the other, or both the "PP" stamp holders who fabricate the piping would have Code design responsibility for the piping.

In Note 1 of PG-101 it is explained that the term "boiler manufacturer" can also mean an "S" stamp holder that is a so-called engineering-contractor organization, with or without fabricating facilities, that has

the capabilities of designing a boiler and of assembling the fabricated parts of a boiler in the field. Such an organization must provide for the design of the unit, that is, it must provide a design specification that establishes the design pressure and temperature conditions for each component of the boiler. The activities of an engineering-contractor organization were described in Interpretation I-92-12, under the uninformative title Certificate of Authorization:

Question: May an organization which provides the specifications, the design, the calculations, and the drawings for the components of a boiler, but which has no manufacturing facilities, obtain a Certificate of Authorization to use the S symbol stamp?

Reply: Yes.

Question: May the holder of the Certificate of Authorization to use the S symbol stamp subcontract any or all aspects of boiler construction so long as he retains Code responsibility for the completed boiler and his quality control system provides for those portions of the work which may be subcontracted?

Reply: Yes.

Although Note 1 of PG-104 appears to limit the issuance of an “S” stamp to engineering-contractor organizations that have the capability of field assembling parts fabricated by other stamp holders, in practice, this is not necessarily so. This can be seen from the above interpretation, as well as the guide to information appearing on the Certificates of Authorization in Appendix A-370.

Several other Interpretations have dealt with the seemingly endless uncertainties that arise as various stamp holders and their subcontractors collaborate in the construction of a boiler. One of these has to do with the furnishing of nameplates. There is no doubt that certain large components, such as a drum, are expected to have stampings or nameplates, as required by the various provisions of PG-106. However, what is less clear is what stamping or nameplates are required for smaller components such as headers or individual superheater elements. Interpretation I-86-32, Nameplates for Boiler Parts, gave some guidance:

Question: Does PG-104 of Section I require manufacturers to provide nameplates in addition to P-4 Partial Data Reports for individual boiler parts such as superheater elements, economizer platens, or waterwall panels?

Reply: No; however, parts must be stamped by the manufacturer in accordance with PG-106.8. Additional guidance is provided in Interpretations I-83-101 and I-83-113.

Interpretation I-83-101 is entitled Marking of Duplicate Boiler Parts:

Question: Where it is impossible to meet the stamping requirements of PG-111, is it permissible to use a nameplate and attach it to the part?

Reply: It is intended that the manufacturer, subject to the approval of the Authorized Inspector, shall provide a stamping which will perform the function otherwise intended by the rules of the Code. A nameplate with the required stamping, securely attached by welding to the part, may be one acceptable solution.

Question: What stamping is required when multiple duplicate parts are supplied for a field assembled boiler by a manufacturer not taking responsibility for the completed boiler unit?

Reply: At least one part shall bear the full Code stamping and duplicate parts shall be identified by comparison of markings on the parts and the description of the part required to complete Form P-4.

Question: What stamping is required when multiple duplicate parts are supplied for a field assembled boiler by a manufacturer not taking responsibility for the completed boiler unit, where it is impossible to meet the stamping requirements of PG-111?

Reply: It is intended that the manufacturer, subject to the approval of the Authorized Inspector, shall provide a stamping which will perform the function otherwise intended by the rules of the

Code. A nameplate with the required stamping, securely attached by welding to at least one part with its location listed on Form P-4, may be one acceptable solution.

Note that a nameplate or stamping on a part such as a superheater tube in a high-temperature zone will not last long. What is usually sufficient is some marking by which the manufacturer and Inspector can assure that the right parts have been installed in the right place. This was addressed in the Code when PG-106.8.2 was revised in the 2001 Edition. The rules now allow for marking in lieu of stamping for parts up to 5 in. (125 mm) O.D. provided the marking remains visible until the part is installed.

Interpretation I-83-11 dealt with the Stamping of Piping Subassemblies:

Question: Is it a requirement of Section I that piping subassemblies of boiler external piping (as defined in PG-58), which are shop fabricated by an organization in possession of a PP symbol stamp, be certified by that organization by completing the front of the P-4A Data Report and applying their PP symbol to each piping subassembly, if the piping is to be installed by welding by another organization?

Reply: Yes, provided that the subassemblies are larger than NPS 2. Where the subassemblies are NPS 2 or smaller, they shall be marked with an identification acceptable to the Inspector and traceable to the required Data Report (see PG-109).

Question: For the piping subassemblies defined in the preceding question, does Section I require the word "part" to be stamped below the PP symbol?

Reply: No.

There is some flexibility in how certain piping components may be supplied and stamped either as parts or as piping. This was addressed in Interpretation I-92-46, Stamping of Boiler Proper Piping:

Question: May fabricated boiler proper piping constructed only by welding as covered by PW-41, and fabricated by a manufacturer or contractor in possession of the pressure piping symbol stamp, be stamped in accordance with either PG-106.8 or PG-109.3?

Reply: Yes.

The second question in this Interpretation dealt with some practical details of how multiple duplicate parts can be covered by stamping one part and providing identifying marks on the others (see precedent in PG-111.10).

Question: A manufacturer or contractor who is not the manufacturer of the boiler fabricates a run of boiler proper piping consisting of multiple spool pieces constructed only by welding as covered by PW-41. May only one spool piece be stamped, the remaining spool pieces be identification stamped, and all spool pieces for this run of piping be reported on one P-4A Data Report Form?

Reply: Yes.

A last Interpretation applies to an increasingly common situation in which purchasers of boilers to be installed outside of the United States of America and Canada want the boilers to be designed and manufactured to Section I of the ASME Code, but not field assembled by an ASME Code stamp holder under the supervision of an Authorized Inspector. Purchasers do this to lower costs, since it is often difficult and, therefore, more costly, to contract with a local assembler possessing the appropriate Certificate of Authorization to perform the work. The boiler that results may be a perfectly satisfactory boiler, but it may not be stamped with a Code symbol or called a boiler that meets the ASME Code. This subject was addressed in Interpretation I-83-106, Use of ASME Marking:

Question: May a power boiler which was designed in accordance with the rules of ASME Section I but which was not subject to authorized inspection or Code symbol stamping be marked on the nameplate with such information as "Design Code: ASME Section I"?

Reply: *No. Such use of the term “ASME” on the nameplate is not in conformance with the “Statement of Policy on the Use of ASME Marking to Identify Manufactured Items,” which appears in the front of Section I That policy includes this sentence: “Markings such as ‘ASME,’ ‘ASME Standard,’ or any other marking including ‘ASME’ or the various Code symbols shall not be used on any item which is not constructed in accordance with all of the applicable requirements of the Code.”*

QUALITY CONTROL SYSTEM

The 1960s was a time of rapid growth for the nuclear power industry. In 1963, a new ASME Code section, Section III, was published to cover construction of nuclear power plant components. One of the features of construction under Section III was a requirement that the manufacturer implement a quality assurance system, a formal system of oversight and record keeping assuring that construction takes place as intended, that the right material, parts, drawings, and procedures are used. The benefits of such a system soon became apparent. In 1973, the ASME Boiler and Pressure Vessel Committee (now the BPV Standards Committees) adopted similar but less comprehensive and detailed rules for what is called a quality control (QC) system for the boiler and pressure vessel sections of the Code, Sections I, IV, and VIII (and now Sections X and XII). In Section I, these rules are found in PG-105.4 and Appendix A-300, both entitled Quality Control System. Each manufacturer is required to have a documented quality control system that is fully implemented into its manufacturing operations. It may be of interest to note that the B31.1 Power Piping Code has no provisions for a quality control system that applies to other than boiler external piping, although the governing committee has been considering the idea for many years.

The QC system is intended to control the entire manufacturing process from design to final testing and certification. The scope of such systems may vary significantly among manufacturers, since the complexity of the work determines the program required; however, the essential features of the QC system are the same for everyone. Each manufacturer is free to determine the length and complexity of its Quality Control Manual, making it as general or detailed as desired. It is not advisable to include detailed practices in the manual that are not actually followed in the shop. Also, when shop practices are revised, the manual must be updated to reflect the revisions. Otherwise, the Authorized Inspector is likely to find nonconformities, which will cause considerable extra work before full compliance with the Code can be demonstrated. Implicit in the Code QC requirements is recognition that each manufacturer has its own established practices, and these are acceptable if a documented system can be developed showing control of the operation in conformance with Code requirements. It is also recognized that some of the information included in a written description of a quality control system is proprietary, and no distribution is required other than to the Authorized Inspector.

An outline of features to be incorporated into a Section I quality control system is found in the Appendix A-302 paragraphs. These paragraphs are a list of requirements that have proven relatively easy to understand and have worked well. To begin, the authority and responsibility of those performing quality control functions must be established. That is, the manufacturer must assign an individual with the authority and organizational freedom to identify quality problems and to recommend and implement corrective actions should they be needed. In addition, the written system must include:

- The manufacturer's organization chart, showing the relationship between management, engineering, and all other groups involved in the production of Code components, and what the primary responsibility is of each group. The Code does not specify how to set up the

organization, nor does it prevent the manufacturer from making changes, so long as the resultant organization is appropriate for doing Code work.

- Procedures to control drawings, calculations, and specifications. That is, the manufacturer must have a system to assure that current drawings, design calculations, specifications, and instructions are used for the manufacture of Code components.
- A system for controlling material used in Code fabrication to assure that only properly identified and documented material is used.
- An examination and inspection program that provides references to nondestructive examination procedures, and personnel qualifications and records needed to comply with the Code. Also required is a system agreed upon with the Authorized Inspector for correcting nonconformities. A nonconformity is any condition that does not comply with the rules of the Code, whether in material, manufacture, or the provision of all required appurtenances and arrangements. Nonconformities must be corrected before the component can be considered to comply with the Code.
- A program to assure that only welding procedures, welding operators, and welders that meet Code requirements are used to produce Code components. This is normally one of the most detailed and important sections of the QC manual, which describes how qualified welding procedures are maintained and used and who within the organization is responsible for them. It also includes details on how welder qualifications are established and maintained.
- A system to control postweld heat treatment of welded parts and any other heat treatment, such as might be required following tube bending or swaging. This system must also provide means by which the Authorized Inspector can verify that the heat treatment was applied.
- A system for calibration of examination, measurement, and test equipment used in Code construction to assure accuracy of such equipment. The Code does not require such calibrations to be traceable to a national standard such as those maintained at the National Institute of Science and Technology (NIST). It merely states that the equipment must be calibrated.
- A system of record retention for such items as radiographs, nondestructive examination (NDE) reports, and Manufacturer's Data Reports.
- Procedures covering certain other activities of the manufacturer, such as hydrostatic testing.
- If a manufacturer intends to subcontract any aspect of Code construction, such as design, radiography, or heat treatment, the procedures and controls for the subcontracting must also be included in the manufacturer's quality control system.

Appendix A-300 concludes with the admonition that the quality control system shall provide for the Authorized Inspector at the manufacturer's plant to have access to all drawings, calculations, records, procedures, test results, and any other documents necessary for him or her to perform the inspections mandated by Section I. The objective is to assure the quality of the construction and compliance with the Code. Note also that the quality control system may not be changed without obtaining the concurrence of the Authorized Inspector.

As explained in Chapter 9, under Code Symbol Stamps, one of the conditions for the issuance or renewal of a Certificate of Authorization to use one of the ASME Code symbol stamps is that the manufacturer or assembler must have, and demonstrate to a review team, a quality control system intended to assure that all Code requirements will be met. The issuance by ASME of a new Certificate of Authorization or the required triennial renewal of an existing Certificate of Authorization is based on a favorable recommendation after a joint review of the written quality control system by the ASME review team.

STANDARD PRESSURE PARTS, VALVES, AND VALVE RATINGS

STANDARD PRESSURE PARTS

The rules dealing with standard pressure parts and how they may be provided are found in PG-11, Miscellaneous Pressure Parts. Ordinarily, Section I requires all pressure parts to meet applicable requirements for material, design, fabrication, welding, inspection, testing, and certification by stamping and data reports. These comprehensive Code construction requirements are considered necessary to ensure safe construction. Considerable relief from this burden is granted in the case of what are called standard pressure parts, provided these parts are designed and manufactured in such a way as to provide an equivalent assurance of quality and safety. Under these circumstances, mill test reports, inspection by an Authorized Inspector, and Partial Data Reports are not required.

Among the parts included in the category of standard pressure parts are such components as: pipe fittings, valves, flanges, welding necks, welding caps, manhole frames and covers, and the casings of certain pumps. Most of these parts are readily available as stock items in a variety of sizes. They do not have to be designed for each specific application because the manufacturer has already established pressure and temperature ratings for them.

Section I establishes several categories of these parts. One category covers pressure parts which are cast, forged, rolled, or die-formed (i.e., not welded). Within this category, Section I designates two types: parts that comply with an ASME (formerly ANSI and later ASME/ANSI) Standard accepted by reference in PG-42 and parts that comply with a parts manufacturer's standard. There are some differences between the two in material and design requirements. Parts complying with a parts manufacturer's standard must be made of material explicitly permitted by Section I, but parts complying with an ASME standard may, in addition, be made of materials listed in that standard, provided Section I does not prohibit or otherwise limit the use of such materials. The ASME standard also establishes the basis for their pressure and temperature rating and specifies the marking on them; these ratings and markings are accepted by Section I. Some difficulties have arisen in recent years if the standard pressure part is not made of a material explicitly approved for Section I construction in Section II, Part D. This situation is explained in Chapter 3, Materials.

In the case of a parts manufacturer's standard, the manufacturer must establish the pressure and temperature rating of the part and the appropriate marking on it. Section I gives no further guidance on how this is to be done, and the manufacturers presumably use generally accepted engineering principles in developing their ratings. Perhaps because of this lack of specific guidance, Section I cautions in footnote 4 to PG-11: "The manufacturer of the completed vessel shall satisfy himself that the part is suitable for the design conditions of the completed vessel."

Another category of standard pressure parts established by Section I is designated by the somewhat awkward title "welded standard pressure parts for use other than the shell of a vessel." This category includes the same kind of parts just described, except that welding is now involved. Since welding is a process involving many variables that when not properly controlled can result in unsatisfactory welds, Section I mandates that the welding must comply with the requirements of PW-26 through PW-39. The substance of these requirements is that the welders, welding operators, and welding procedures must be qualified under the provisions of Section IX of the Code. If a standard welded pressure part were used for the shell of a vessel, full Code requirements would be invoked, including inspection and data reports, since the pressure-containing function of a vessel shell is considered of prime importance to safety, and at least the longitudinal seam in the shell has to be radiographed. This was clarified in the 2000 Addenda when Note 6 of PG-11 was revised to explain that fusion-welded pipe, "with added filler metal," is subject to the same requirements of a shell made from plate.

PG-11 permits any required radiographic examination or heat treatment of welded standard pressure parts to be performed either in the plant of the parts manufacturer or in the plant of the manufacturer of the completed vessel: If radiography is done at the parts manufacturer's plant, the radiographs and inspection report must be sent to the vessel manufacturer and made available to its Authorized Inspector. If the parts manufacturer performs any required heat treatment, it must so certify and that certification must also be made available to the AI. As in the case of manufacturer's standard pressure parts, Section I again cautions that the manufacturer of the completed vessel must be satisfied that a welded standard pressure part is suitable for the design conditions specified for the completed vessel.

In addition to standard pressure parts, PG-11 permits the use of cast, forged, rolled, or die-formed non-standard pressure parts (again note that welded parts are excluded) for components such as shells, heads, and cover plates. These parts are supplied and treated as though they were materials and must have appropriate mill test reports and marking. Once again, the vessel manufacturer is charged to satisfy himself of the suitability of the parts for the intended design conditions.

In general, the marking required by PG-11 on the various kinds of pressure parts it covers serves to identify the parts manufacturer and the pressure and temperature rating of the part. It is also construed as the parts manufacturer's certification that the part complies with an appropriate material specification and is suitable for the rating indicated.

Note that these parts manufacturers need not be holders of certificates of authorization to use Code symbol stamps. Thus, there is no Authorized Inspector monitoring the part manufacturer's operations. However, these standard parts are made under controlled shop conditions by manufacturers who know they are responsible for the satisfactory performance of their products, and the system has worked well without Code inspection and certification.

VALVES AND VALVE RATINGS

This discussion pertains to the pressure-containing, as opposed to the fluid-flow, aspects of valve selection, the latter being beyond the scope of Section I. Many valves are used on a boiler and its associated piping. The valves often establish the boundary of the boiler, that is, the jurisdictional limits of Section I, since boiler external piping is defined as that piping that begins where the boiler proper terminates and "extends up to and including the valve or valves required by this Code". Thus, most valves are associated with boiler external piping. A concise illustration of some of the valves typically required on a boiler is given in Figs. PG-58.3.1 (a to c), PG-58.3.2 and PG-58.3.3. Rules covering valves and valve ratings are found in PG-11, PG-42,

PG-58, PG-59, PG-60, and PW-42. Specific valve application requirements are given in PG-58, PG-59, and PG-60. These requirements are stated in somewhat greater detail in paragraph 122.1 of ASME B31.1, Power Piping, which since 1972 has had jurisdiction over boiler external piping for all aspects of construction except Authorized Inspection and Code Certification.

Usually only one valve is required on piping connected to the boiler. There are several exceptions to this rule, all safety related. A blowoff usually requires two valves, one slow opening, to provide for close control when water is blown out when the boiler is under pressure. Two main steam stop valves with an ample free-blow drain between them are required if boilers with manways are connected to a common steam header. When such boilers are out of service, an inspector or other worker could be working inside, and the object is to provide two layers of protection against inadvertent opening or leakage of the valves on the pipe leading to the common header. The Committee voted to approve the extension of this double-barrier requirement to any steam line that could supply steam to a boiler with a manway. This new provision appeared in the 1997 Addenda to Section I.

Often there is confusion about valves used on a boiler. They are mistakenly described as “Section I valves.” They should rather be described as valves that meet Section I (or B31.1) requirements. The exception is pressure relief valves, which do require stamping as Section I valves. The other valves do not; they are supplied under the category of standard pressure parts (PG-11), either under an ASME product standard or a manufacturer’s standard. The Power Piping Code, B31.1, accepts and rates valves on virtually the same basis as Section I (per B31.1, paragraph 107).

Most boiler valves comply with the product standard for valves, ASME B16.34, Valves — Flanged, Threaded, and Welding End. This standard provides a series of tables, for various material groups, giving pressure-temperature ratings according to what are called pressure classes. The classes typically vary from the 150 class (the weakest) to the 4500 class (welded only — not flanged or threaded). For each class, the allowable pressure is tabulated as a function of temperature. The allowable pressure at any temperature is the pressure rating of the valve at that temperature. Temperatures range from the lowest zone, -20°F (-30°C), to 850°F (455°C) and higher depending on the material group. The allowable pressure for the valve falls with increasing temperature, since it is based on the allowable stress for the material.

Flanged valves are only available as standard class valves and only in ratings up to 2500 class. The 4500 class rating only applies to welding end valves. The pressure class ratings for welding end valves and threaded valves are further identified as standard class, special class, and limited class. Special class valves are the same as standard class valves but are subjected to more rigorous rules for nondestructive examination, defect removal, and repair, and in consequence are permitted higher pressure ratings. Limited class, which is limited to NPS $2\frac{1}{2}$ (DN 65) and smaller, are permitted at higher pressure ratings based on additional wall thickness in designated areas of the valve.

For Section I service, the designer must select a valve whose pressure rating at design temperature is adequate for the maximum allowable pressure (MAWP) of the boiler. However, this choice is complicated somewhat by the fact that both feedwater and blowoff piping must be designed for a higher pressure than the MAWP of the boiler, in recognition that this service is potentially more severe. (See Shock Service in Chapter 5.) This higher pressure, sometimes called the adjusted maximum allowable working pressure, is defined in 122.1.3 of ASME B31.1, Power Piping, as the lower of $\text{MAWP} + 225 \text{ psi}$ ($\text{MAWP} + 1550 \text{ kPa}$) or 1.25 times MAWP.

Because of this complication, Section I had, until the 2007 Edition, provided Appendix Table A-361, which gave the maximum allowable working pressure of the boiler for which various classes of valves and fittings were considered adequate. This table was provided as a convenience to the users, especially Authorized Inspectors, who could then quickly determine whether valves of a given class were adequate for their intended service; however, this table only addressed a single material group. Many years ago, the underlying ASME valve and flange ratings were expanded to cover more materials, and the usefulness of Table A-361 became outdated. The table was deleted in the 2007 Edition. As explained during BPV I deliberations regarding the proposal, the table had been used to illustrate application of some pressure design criteria for feedwater and blowoff piping, but over time, the table came to provide a very limited listing of pressure and temperature ratings already provided in ASME Standards B16.5 and B16.34.

Prior to deletion of the table, BPV I had received a number of inquiries on how the pressures in the table were determined. One such inquiry was responded to in Interpretation I-83-91. While this interpretation is now obsolete with many references to Section I paragraphs and standards outdated, it is included here because it still provides a useful explanation of the multistep procedure for determining the maximum boiler pressure for which certain ASME standard components may be used (see fourth question and reply) as well as the application of valves in Section I service.

Question: *Does PG-42 apply to butt welding end valves?*

Reply: *Yes.*

Question: *Does PG-42 permit the use of both Standard and Special Class valves?*

Reply: *PG-42 permits the use of valves meeting ANSI B16.34, Steel Valves, Flanged and Butt Welding End. As explained in paragraph 2 of that standard, flanged valves are designated as Standard Class only. However, butt welding end valves may be designated either Standard Class or Special Class, and may also be assigned Intermediate Ratings. Note that a valve may not be designated Special Class unless it meets all requirements for that class given in paragraph 8 of ANSI B16.34.*

Question: *Please explain the deflection limits and factor of safety mentioned in PG-41.4.5 (Summer 1983 Addenda).*

Reply: *For butt welding end valves, paragraph 6.1.4 of ANSI B16.34 provides a method for establishing the required wall thickness for valves with intermediate pressure ratings. When this method is used, the factor of safety will be maintained as required. However, it remains the responsibility of the designer to assure that valve deflection under load will not affect its proper operation.*

Question: *How are the pressures shown in Table PG-42 (now Table A-361) determined?*

Reply: *Section I rules (PG-11) permit the use of standard pressure parts such as valves and flanged fittings which comply with an ANSI product standard listed in PG-42. The ANSI standards (ANSI B16.34, Steel Valves, Flanged and Butt Welding End; and ANSI B16.5, Steel Pipe Flanges and Flanged Fittings) provide pressure-temperature ratings for these components. The actual choice of fitting is complicated somewhat by the fact that Section I and ANSI B31.1 mandate certain overpressure design requirements for boiler feed and blowoff line service (see ANSI 1131.1, 122.1), and also because the rating of a fitting is a function of the material as well as of the pressure class. The user must therefore follow a multistep procedure which varies depending on whether saturated steam service or boiler feed and blowoff service is involved:*

- (1) *Establish boiler maximum allowable working pressure P .*
- (2) *Establish feedwater and blowoff line pressures P_F or P_B as lesser of $P_F = (P + 225 \text{ psi})$ or $P_F = 1.25P$.*
- (3) *Select fitting material.*
- (4) *Use either the ANSI B16.34 or ANSI B16.5 pressure-temperature ratings for that material group. Check successively higher pressure classes until one is found whose pressure rating, at the saturation temperature corresponding to P , equals or exceeds the required pressure rating (P_F or P_B for feedwater or blowoff lines, P for saturated steam lines). That is the pressure rating, or class, required for the fitting.*

Table PG-42 (now Table A-361) is provided merely as a convenience to the user, but as explained in the table, the pressures listed are applicable only to Standard Class components of Material Group 1.1. For other materials and classes, the maximum allowable pressures must be determined using the procedure given above.

A design exercise involving the selection of a feedwater stop valve following the above-described procedure is provided in Appendix IV.

PRESSURE-RELIEF VALVE REQUIREMENTS

INTRODUCTION

The ASME Boiler and Pressure Vessel Code was developed between 1911 and 1914 as a set of safety rules to address the serious problem of boiler explosions in the United States, which at that time were almost a daily occurrence. Average steam pressure in boilers in those days had reached about 300 psi (2 MPa), and the explosions took a heavy toll of lives and property. The principal design basis for boilers and pressure vessels is the safe containment of design pressure. Protection against overpressure was therefore a very important aspect of pressure vessel design. Accordingly, that first edition of what is now Rules for Construction of Power Boilers, Section I of the Code, included rules for the overpressure protection of boilers, based on the best industry practice at the time. The principles of today's Code rules for overpressure protection are little changed from those of the first Code.

That first ASME Code of 1914 has now grown into 12 book sections, covering a wide variety of subjects. Six of these book sections deal specifically with the design of pressure vessels and include requirements for overpressure protection. The various pressure-relief devices used for overpressure protection may be categorized as pressure-relief valves (commonly called safety valves), and nonreclosing devices, such as rupture disks.

The function of a pressure-relief device is to open at a specified pressure and pass a sufficient amount of fluid to prevent pressure in the vessel or system being protected from exceeding an **allowable overpressure** above the design pressure. In some book sections such as Sections I and VIII, the design pressure is referred to as the **maximum allowable working pressure (MAWP)**. Each book section provides rules for determining the required relieving capacity of pressure-relief devices, for establishing allowable overpressure, for determining the maximum set pressure of the pressure-relief devices, and for ensuring that pressure-relief devices will function as required should an overpressure condition occur. Although fundamentally similar, the rules vary somewhat in detail and complexity, reflecting the nature of the application and the somewhat different design philosophies of the committees governing the various book sections. It happens that the Code offers only limited explanation of its rules on overpressure protection, and aside from certain functional requirements, very few rules to guide the designers of pressure-relieving devices. The objective of this chapter is to summarize the Section I rules and to provide some explanation and discussion of them and how they are applied. Since similar rules apply to all the non-nuclear book sections, a brief explanation of those other rules is included, to point out some differences. Thus, the discussion which follows covers all the non-nuclear book sections, with the major emphasis on the rules in Section I.

ASME has a policy that rules on a given subject that appear in more than one book section should be similar and consistent, insofar as possible. However, due to the diversity of application, there is some variation

among the pressure-relief device rules that have evolved in six book sections of the Code. A governing standards committee of the Board of Pressure Technology Codes and Standards has the fundamental responsibility for writing, revising, adding to, and interpreting the rules of each book section of the Code. Assisting the book section standards committees with technical advice relating to pressure-relief valves is the Subcommittee on Safety Valve Requirements (SC-SVR). The purviews of the book and of the service committee overlap somewhat, and the demarcation of their respective responsibilities is sometimes unclear. Traditionally, matters of application and installation, such as which devices are permitted and where, fall within the domain of the book section committees. Technical matters dealing with design, testing, and capacity certification are covered by the SC-SVR. When inquiries dealing with these devices are received by the ASME, they are sent to the concerned book section committees. Only if those committees think it necessary or advisable is the inquiry forwarded to SC-SVR for a recommended reply or rule change. But even in such cases, the book section committee is free to accept, modify, or reject that recommendation. Thus, despite ASME policy on consistency of rules, the independence of all the committees involved has resulted in some slight gradual divergence among the book sections with respect to their rules for overpressure protection.

To provide overpressure protection, the designer must first determine potential sources of overpressure, calculate the rate at which fluid must be removed under emergency conditions to maintain pressure within maximum allowable limits, and select appropriate relieving devices to provide this required capacity. The Code provides a variety of rules for the design, manufacture, capacity certification, selection, and application of pressure-relief devices used to protect a broad variety of fired and unfired vessels. Early applications of the Code dealt with steam boilers, where the source of pressure is the application of heat to water in an enclosed vessel, producing steam. If the quantity of steam allowed to leave the vessel is less than that being generated, the pressure in the vessel rises. The same principle applies to other fluids heated in closed vessels. Providing sufficient overpressure protection is not always straightforward, however, and the Code rules differ depending on the type of vessel to be protected, as described next.

OVERPRESSURE PROTECTION

Relieving Capacity Required

The first task in selecting appropriate pressure-relief devices for a vessel or system is to determine the required relieving capacity (the rate at which fluid must be removed from the system during an emergency condition to maintain a safe level of pressure). This requires that all sources of fluid flow or energy into the system be considered and evaluated. Sources of energy might be heat, fire, chemical reaction, or mechanical work. Sources of fluid flow could include compressors, pumps, pressure-reducing valves stuck in the open position, malfunctioning control valves, inadvertent opening or closure of a valve connected to the vessel, failure of an internal tube in a heat exchanger, or some combination of these events. Each possible source of excess energy or fluid flow into the system must be taken into account to determine the worst case overpressure condition. The required relieving capacity is determined from this worst case; this determination can often require careful engineering study. The various book sections of the Code in some cases provide directly applicable rules and, in other cases, only limited guidance for determining the worst case overpressure condition. The following is a brief summary of those rules.

Summary of Rules for Determining Required Relieving Capacity, by Book Section

Section I still uses the basic rule from the first ASME Code in 1914 which, in brief, requires pressure-relief valve capacity sufficient to relieve all the steam a drum-type boiler can generate without allowing the pressure to rise more than 6% above the set pressure of the highest set valve, and in no case more than 6% above the MAWP. This rule is now supplemented by others, for certain types of boilers and for various other components covered by Section I. For example, the required relieving capacity in lb/hr (kg/hr) for an iso-

lable economizer (one with valves on either side, which could be left closed) is equal to the maximum heat absorbed in Btu/hr (W) divided by 1000 (646) — see PG-67. This rule was based on the assumption that it takes 1000 Btu (293 W) to boil a pound of water. This is a fair assumption at low pressures, but somewhat unconservative at higher pressures. For high-temperature water boilers, this rule is reversed: the designer is told to provide relieving capacity equal to the boiler output in Btu/hr (W) divided by 1000 (646). If a superheater can be valved off (isolable) from a boiler, or is a nonintegral separately fired superheater, it must also be equipped with one or more pressure-relief valves having a discharge capacity based on the heating surface of the superheater. The rules also permit the relieving capacity of the superheater pressure-relief valves to be calculated by the boiler manufacturer based on the maximum expected heat absorption (as determined by the manufacturer) in Btu/hr (W) divided by 1000 (646) — see PG-68.3. These superheaters must also be stamped with either the heating surface or the minimum pressure-relief valve discharge capacity (see PG-106.4.2.e).

Until 1994, when its rules were revised, Section I had provided a table (Table PG-70) for certain types of boilers. Table PG-70 stipulated the minimum pressure-relief valve relieving capacity required per square foot of heating surface, with the admonition that this was only a minimum and that more might be required. This minimum capacity varied with boiler type, firing method, fuel, and type of heating surface. The table was originally intended as a guide for Inspectors, who could then verify the boiler manufacturer's choice of pressure-relief valve capacity. The capacities listed in Table PG-70 were found to be inappropriate for certain types of boilers, e.g., fluidized bed boilers and stoker fired boilers firing refuse. To correct this problem, and also to eliminate some confusion between the maximum designed steaming capacity mentioned in PG-67 and the minimum required pressure-relief valve relieving capacity specified in PG-70, these two paragraphs were revised in the 1993 Addenda to Section I. The new wording clearly placed on the boiler manufacturer the full responsibility for determining the maximum designed steaming capacity of the boiler and for providing at least that much pressure-relief valve relieving capacity. At the same time, a new rule was added requiring the boiler manufacturer to stamp the maximum designed steaming capacity on the boiler nameplate. With these changes, the old Table PG-70 was no longer needed. However, to keep it available to Inspectors accustomed to using it, it was moved to a nonmandatory appendix, Appendix A-44, where it is now called Table A-44.

The term “all the steam the boiler can generate” has traditionally been interpreted to mean the maximum continuous rating (MCR) of the boiler at specified design conditions. This was clarified by Section I in the 2004 Addenda when PG-67.2.1 was revised to say “the minimum design steaming capacity *at the MAWP of the boiler*” (Italics added). Section I assigns the responsibility for the determination of this steaming rate to the boiler manufacturer, who calculates it based on experience, taking into account the various boiler systems: pumps, fans, and fuel. It is necessary in all such systems to provide some design margin to assure achieving design steam-generating capacity (MCR) and to permit the overfiring necessary when increasing load. Consequently, if all systems were pushed to their limits, it is possible to exceed the nominal design steam-generating capacity. However, the customary practice is to use the nominal steaming capacity at MAWP as the minimum pressure-relief valve relieving capacity required. This can be justified by the safety margins implicit in the certified capacities, in the design of the pressure parts, and in the overpressure limits of Section I.

In 1965, Section I incorporated design rules for a then new type of boiler called a “forced-flow steam generator with no fixed steam and waterline, equipped with automatic controls and protective interlocks responsive to steam pressure.” Such boilers have no steam drums; the fluid passes through the boiler only once, entering as water and leaving as steam. Unlike drum-type boilers, which are designed for a single design pressure and which achieve their pressure by firing, forced-flow steam generators with no fixed steam and waterline achieve their pressure from the boiler feed pump. These boilers are designed for different pressure levels along the path of water-steam flow, with a significant difference in pressure between the economizer inlet and superheater outlet, for example, 4350 psi (30 MPa) versus 3740 psi (25.8 MPa), respectively.

Recognizing the special nature of these boilers, Section I provided alternative rules for their overpressure protection, in PG-67.4, which are quite different from the usual Section I rules. For drum-type boilers, Section I permits credit for use of spring-loaded pressure-relief valves only. However, for these once-through

boilers, Section I permits a combination of spring-loaded pressure-relief valves and power-actuated pressure-relieving valves, the latter to provide a minimum of 10%, but to be credited with no more than 30%, of the required relieving capacity. Moreover, PG-67.4.1 permits the installation of an isolating stop valve between the power-actuated pressure-relieving valve and the boiler to permit repairs, provided certain conditions are met. In another departure from usual practice, any or all of the spring-loaded pressure-relief valves may be set above the MAWP of the part to which they are connected provided the MAWP of any part of the boiler is not exceeded by 20% when all the pressure-relief valves on the boiler are in operation. Further, the power-actuated relieving valves must receive a signal to open when the MAWP at the superheater outlet is exceeded. When still further special conditions are met, Section I permits certain forced-flow steam generators to be furnished with as few as two pressure-relief valves whose total relieving capacity is not less than 10% of the maximum design steaming capacity. These special conditions include the use of automatic controls and direct acting trip mechanisms for the fuel and feedwater supplies, actuated by the lifting of the valve stem of at least two pressure-relief valves. Further, the fuel and feedwater control circuitry must be fail-safe.

Section IV, Heating Boilers, covers three types of relatively low pressure equipment: steam heating boilers, hot water heating or supply boilers, and potable water heaters. The pressure-relieving capacity, in pounds of steam per hour (kg/hr), for both steam and water boilers may be determined in one of two ways: the maximum Btu output at the boiler nozzle divided by 1000 (again, the rule of thumb that 1000 Btu will boil a pound of water) or by use of a table of minimum steam-relieving capacity per hour per square foot (square meter) of heating surface, similar to the method formerly used in Section I. The relieving capacity of pressure-relief valves on potable water heaters is specified in Btu/hr and, in general, must equal the maximum input to the heater. HG-402.7 advises that the relieving capacity in terms of Btu may be determined by multiplying the capacity in pounds of steam per hour W by 1000.

Of all the book sections, **Section VIII, Pressure Vessels**, covers the largest variety of vessels. These vessels are also potentially subject to overpressure conditions from many possible sources. When designers of Section I and Section IV equipment determine required relieving capacity, they often start with guidelines from the Code and knowledge of a boiler's maximum steam-generating capacity or heat input. By contrast, Section VIII designers are simply charged by UG-125 with preventing the pressure from rising more than a certain amount above the MAWP of the vessel, with few additional guidelines. Accordingly, the designer must often use the engineering principles outlined in the section on Required Relieving Capacity above and have a thorough knowledge of the system being protected to determine the appropriate relieving capacity. Section VIII comprises 3 volumes, Divisions 1, 2, and 3. Division 2 has alternative rules for the construction of pressure vessels, based on the design-by-analysis methods of Section III. However, the overpressure protection requirements of Divisions 1 and 2 are virtually identical. Division 3, *Alternative Rules for Construction of High Pressure Vessels*, was published in 1997. It contains special rules for overpressure protection.

Section X, Fiber-Reinforced Plastic Vessels, adopts the same basic overpressure rules as Section VIII, Division 1. When a Section X vessel is used for Section IV potable water service, the vessel is restricted to internal pressure only; therefore, a vacuum relief valve is required. Generally, the pressure-relief devices required by Section X must meet the applicable Section IV or Section VIII requirements. As with Section VIII, the task of determining required relieving capacity is left to the designer, but in contrast to Section VIII, it is the manufacturer's responsibility to assure that adequate pressure-relieving devices are selected and installed.

Section XII, Transport Tanks, (described as cargo, rail, portable cryogenic, and ton tanks), provides diverse requirements for pressure-relief systems. The rules not only provide for pressure relief, but also, under certain circumstances, vacuum relief. Generally, transport tanks must be provided with one or more spring-loaded, reclosing pressure-relief valves. For certain types of transport tanks, secondary pressure-relieving devices (i.e., rupture discs) may be used. Under certain circumstances, these secondary relief devices are mandatory. As an alternative to certification and stamping in accordance with Section XII, pressure-relief devices stamped with the Section VIII "UV" or "UD" symbol may be used provided the device meets the applicable requirements of Section XII. Similar to Section VIII, Div. 1, it is the transport tank user's responsibility to assure that the required pressure-relieving devices are installed. The manufacturer of the tank need

PRESSURE-RELIEF DEVICES ALLOWED BY THE ASME CODE	BOOK SECTION				
	I	IV	VIII	X	XII
Direct Spring-Loaded Pressure-Relief Valve	•	•	•	•	•
Pilot-Operated Pressure-Relief Valve	•		•	•	
Power-Activated Pressure-Relief Valve	•				
Rupture Disk Device	◊		•	•	+
Pin Devices			•		+
Pin Devices in Combination with Pressure-Relief Valves			•		•
Spring-Loaded Nonreclosing Pressure-Relief Device			•		
Open Flow Paths or Vents			•		
Fusible Plugs — Direct to Atmosphere					▲

• Permitted

◊ In combination with pressure-relief valve on organic fluid vaporizer only

+ In combination with pressure-relief valve. May be sole overpressure protection device when permitted by governing jurisdiction (Competent Authority)

▲ For Ton tanks only

TABLE 12.1
PRESSURE-RELIEF DEVICES ALLOWED BY THE ASME CODE

not supply the pressure-relieving devices. Owing to the mobile nature of these tanks, it is not surprising that Section XII cautions that regulatory authorities governing use of transport tanks may specify different operating characteristics for the pressure-relieving devices.

Allowable Overpressure

Most pressure-relief devices, particularly pressure-relief valves, require a further increase in pressure above set pressure to reach a full open condition. Vessels with multiple valves may require an even greater increase over MAWP for all the relieving valves to open fully because some are allowed to be set above MAWP. Accordingly, each book section provides its own rules as to how much the pressure is allowed to increase above MAWP or design pressure during an overpressure event.

Section I provides for overpressure within very narrow limits. With some exceptions (see discussion of forced-flow steam generators, above), pressure may not rise more than 6% above the set pressure of any pressure-relief valve, and in no case more than 6% above the MAWP.

Section IV overpressure limits vary somewhat, depending on the type of equipment and its design pressure. For steam boilers, the design pressure is a minimum of 30 psi (200 kPa), but the operating limit set by Section IV is 15 psi (100 kPa), so the pressure-relief valves must be set at 15 psi (100 kPa), with an overpressure of 5 psi (35 kPa) allowed. For hot water boilers with only a single pressure-relief valve, an overpressure that is 10% above MAWP is allowed. Where multiple valves are provided, the allowable overpressure is 10% above the set pressure of the highest set valve.

Section VIII limits on overpressure depend on the type of installation. In general, Section VIII mandates that pressure not be allowed to rise more than 10% or 3 psi (20 kPa), whichever is greater, above MAWP. When multiple devices are used, or additional devices are provided to protect against exposure to fire, overpressures of 16% or 21%, respectively, are allowed. For valves that protect liquefied compressed gas storage vessels against exposure to fire, 20% overpressure is allowed.

Section X has essentially the same overpressure requirements as Section VIII, except that special rules for protection of liquified compressed gas storage vessels exposed to fire are not considered.

Section XII provides for varying overpressure limits based on the type of transport tank and contents. For Class 1 Cargo tanks, the pressure-relief valve(s) may not be set greater than 110% of MAWP. For insulated

Class 1 Cargo tanks, the internal pressure is not to exceed the tank test pressure, generally 130% of MAWP. For Cryogenic portable tanks, the internal pressure is not to exceed 120% of MAWP. The internal pressure of Ton tanks is not to be allowed to exceed 82.5% of the tank test pressure which varies depending on the tank category. At this writing, Section XII has not addressed overpressure limits for Rail tank cars.

Set Pressure of Pressure-Relief Devices

Once the required relieving capacity and allowable overpressure have been established, the next step is to determine the set pressure of the pressure-relief devices. The general rule for setting pressure-relief devices is that at least one device must be set to open at or below maximum allowable working pressure (the design pressure) of the system or vessel being protected. On many small boilers or pressure vessels, only one relief device is required, and this device is typically set at MAWP. When more than one device is used, the additional devices may be set at slightly higher pressures. This allowable increase in set pressure over MAWP varies considerably throughout the Code (in general, from 3% to 10% above MAWP), depending on the application and the circumstances, as shown in Table 12.2.

Section I requires that at least one pressure-relief valve be set at or below MAWP. Additional valves may be set up to 3% above MAWP. In no case, however, may the complete range of settings of all the saturated steam pressure-relief valves on a drum-type boiler exceed 10% of the highest pressure at which any such valve is set. These rules apply primarily to pressure-relief valves on the drum. Section I does not advise a specific setting for pressure-relief valves on superheaters. Industry practice is to set these valves sufficiently below MAWP, so that they will lift before the valves on the drum, thus helping to maintain a cooling flow of steam through the superheater.

Section IV steam boilers have an operating limit of 15 psi (100 kPa), so the pressure-relief valves must be set at 15 psi (100 kPa). Hot water heating boilers and hot water supply boilers are designed for pressures between 30 psi (200 kPa) and 160 psi (1100 kPa) and/or temperatures not exceeding 250°F (120°C). (Above these limits, the boiler would, by definition, be a power boiler falling within the scope of Section I.) When one pressure-relief valve is used on hot water heating boilers, it must be set at or below the MAWP. When more than one pressure-relief valve is used on a hot water heating or supply boiler, the additional valve(s) may be set at up to 10% above MAWP up to 60 psi (400 kPa) and up to 5% above MAWP that exceeds 60 psi (400 kPa).

Potable water heaters are designed for pressures up to 160 psi (1100 kPa) [with a minimum of 100 psi (700 kPa)] and for temperatures not exceeding 210°F (99°C). Although Section IV calls for each such heater to have at least one pressure-relief valve or pressure-temperature relief valve, they are routinely furnished with the latter type, which is activated either by pressure or temperature. The purpose of the 210°F (99°C) limit is to prevent any water discharged from relief valves from flashing to steam. The pressure setting of a single pressure-relief valve, or the low set valve when multiple valves are used, must be less than or equal to the MAWP of the heater, but is further limited to the lowest pressure for which any other component of the hot water system is designed. When used, additional pressure-relief valves may be set no higher than 10% over the set pressure of the lowest set valve.

Sections VIII and X require one valve to be set at or below MAWP. If additional valves are utilized, they may be set up to 5% above MAWP. Section VIII further allows a supplemental valve added to a vessel to protect against hazard due to fire to be set up to 10% above MAWP.

As mentioned earlier, **Section XII** may have the most diverse overpressure protection rules of any book section. Class 3 Cargo tanks require at least one pressure-relief valve set at no less than 120% of MAWP and not more than 132% of MAWP. Additional valves, if used, shall be set at no less than 120% of MAWP. Class 1 vacuum insulated Cargo tanks require two pressure-relief systems. The primary pressure-relief valve on such tanks may not be set for more than 110% of the MAWP. Section XII does not provide specific pressure-relief set pressures for other Class 1 Cargo tanks (e.g., anhydrous ammonia, chlorine, sulfur dioxide, etc.), but requires the tanks to be equipped with pressure-relief valves for the value of the MAWP, which

varies depending on the content. For Cryogenic portable tanks, a minimum of two pressure-relief valves must be set to open at not less than the MAWP and to be fully open at 110% of MAWP. For Ton tanks, fusible plugs must function at a temperature of 175°F (79°C) but not less than 130°F (54°C). Pressure-relief valves, if used, are to be set at various minimum pressures depending on the tank Category.

Set Pressure Tolerance

Each book section provides set pressure tolerances for a variety of applications. These are summarized in Tables 12.2.

PRESSURE-RELIEF DEVICE OPERATING REQUIREMENTS				
APPLICATION	ALLOWABLE VESSEL OVER PRESSURE (ABOVE MAWP OR VESSEL DESIGN PRESSURE)	SPECIFIED PRESSURE SETTINGS	SET PRESSURE TOLERANCE WITH RESPECT TO SET PRESSURE	REQUIRED BLOWDOWN
Boilers	6% (PG-67.2)	One valve $\leq$ MAWP Others up to 3% above MAWP (PG-67.3)	± 2 psi (15 kPa) up to and including 70 psi (0.5 MPa) $\pm 3\%$ for pressure above 70 psi (0.5 MPa) up to and including 300 psi (2.1 MPa) ± 10 psi (70 kPa) for pressures above 300 psi (2.1 MPa) up to and including 1000 psi (7 MPa) $\pm 1\%$ for pressures above 1000 psi (7 MPa) (PG-72.2)	Minimum: 2% of set pressure or 2 psi (15kPa) whichever is greater (PG-72.1) Maximum For Initial Valve Capacity Certification (PG-69.1.4): - 4 psi (15 kPa) for pressure < 100 psi (700 kPa) - 4% of set pressure for pressures of 100 psi (700 kPa) and greater - 10% of set pressure for high temperature hot water boilers and once through forced flow steam generators Maximum For Valve Capacity Recertification (PG-73.4.3): - 4 psi (30 kPa) for pressure < 67 psi (500 kPa) - 6% of set pressure ≥ 67 psi (500 kPa) and < 250 psi (1700 kPa) - 15 psi (100 kPa) for pressure > 250 psi (1700 kPa) and < 375 (2500 kPa) - 4% of set pressure ≥ 375 psi (2500 kPa) - 10% of set pressure for high temperature hot water boilers and once through forced flow steam generators
Forced Flow Steam Generators	20% (PG-67.4.2)	May be set above MAWP but must meet overpressure requirements (PG-67.4.2)	Same as above (PG-72.2)	Same as above.

TABLE 12.2(a) SECTION I

PRESSURE-RELIEF DEVICE OPERATING REQUIREMENTS				
APPLICATION	ALLOWABLE VESSEL OVERPRESSURE (ABOVE MAWP OR VESSEL DESIGN PRESSURE)	SPECIFIED PRESSURE SETTINGS	SET PRESSURE TOLERANCE WITH RESPECT TO SET PRESSURE	REQUIRED BLOWDOWN
Steam Boilers	5 psi (35 kPa) — (HG-400.1e)	≤15 psi (100 kPa) — (HG-400.1a)	±2 psi (15 kPa) — HG-401.1k)	2 psi (15 kPa) to 4 psi (30 kPa) — (HG-401.1e)
Hot Water Boilers	10% for a single valve 10% above highest set valve for multiple valves (HG-400.2g)	One valve at or below MAWP (HG-400.2a & b) Additional valves up to 6 psi (40 kPa) above MAWP for pressures to and including 60 psi (400 kPa) and up to 5% for pressures exceeding 60 psi (400 kPa) — (HG-400.2c)	±3 psi (20 kPa) up to and including 60 psi (400 kPa) ±5% for pressures exceeding 60 psi (400 kPa) — (HG-401.1k)	None specified

TABLE 12.2(b) SECTION IV

PRESSURE-RELIEF DEVICE OPERATING REQUIREMENTS (DIVISION 2 REFERENCES DIVISION 1 REQUIREMENTS FOR OVER PRESSURE PROTECTION AND RELIEF DEVICES – SEE DIV. 2 PART 9)				
APPLICATION	ALLOWABLE VESSEL OVERPRESSURE (ABOVE MAWP OR VESSEL DESIGN PRESSURE)	SPECIFIED PRESSURE SETTINGS	SET PRESSURE TOLERANCE WITH RESPECT TO SET PRESSURE	REQUIRED BLOWDOWN
Divisions 1 and 2				
All vessels with exceptions shown below (UG-125a)	10% or 3 psi (20 kPa) whichever is greater (UG-125c)	≤ MAWP of vessel (UG-134a)	± 2 psi (15 kPa) up to and including 70 psi (500 kPa)	Not specified
Exceptions: When multiple devices are used	16% or 4 psi (30 kPa) — whichever is greater (UG-125c1)	One valve ≤ MAWP, additional valves up to 105% of MAWP (UG-134a)	± 3% over 70 psi (500 kPa) — (UG-134d1)	Note: Pressure-relief valves for compressible fluids having an adjustable blowdown construction must be adjusted prior to initial certification testing so that blowdown does not exceed 5% of set pressure or 3 psi (20 kPa), whichever is greater (UG-131c3a)
Supplemental devices to protect against fire	21% (UG-125c2)	Up to 110% MAWP (UG-134b)		
Devices to protect liquified compressed gas storage vessel in fire (Div. 1 only)	20% (UG-125c3a)	≤ MAWP (UG-125c3b)	-0% +10% (UG-134d2)	
Bursting disks and pin devices	Same as above	Marked burst or set pressure to meet requirements above (UG-127a1 and UG-127b1)	± 2 psi (15 kPa) up to and including 40 psi (300 kPa) ± 5% of marked pressure (UG-127a1 and UG-127b1)	

PRESSURE-RELIEF DEVICE OPERATING REQUIREMENTS				
Spring-loaded non-reclosing device Division 3	Same as above	Same as above (UG-127c1)	$\pm 5\%$ of marked set pressure (UG-127c1)	
All vessels with exception shown below (KR-100)	10% above design pressure (KR-150)	$\leq$ Design pressure (KR-162)	$\pm 3\%$ of valve set pressure (KR-300c), $\pm 5\%$ of marked pressure setting of rupture disk (KR-201)	None specified
Exception: When multiple devices are used	Same as above (KR-162)	One valve $\leq$ MAWP, additional valves up to 105% of design pressure (KR-162)	Same as above for applicable device (KR-123b)	

TABLE 12.2(c)
SECTION VIII DIVISIONS 1, 2 AND 3

Blowdown

A pressure-relief valve will generally not reseal until the inlet pressure is reduced below set pressure. The difference between actual opening pressure and reseating pressure is called blowdown. For Section I, the minimum blowdown is the greater of 2 psi (15 kPa) or 2% of set pressure. Maximum blowdown settings have been established for the initial capacity certification tests (PG-69.1) and the capacity recertification tests (PG-73.4) for each valve design and size. For initial certification, the maximum blowdown for valves set at or below 100 psi (700 kPa) is 4 psi (30 kPa). For valves used on high-temperature hot water boilers and forced flow steam generators, the maximum blowdown is 10%. For all other valves, the maximum is 4% of set pressure. For recertification testing (done at 5-yr intervals), a range of somewhat less stringent maximum blowdown settings is provided. While not explained in Section I, it is likely that the blowdown rules for recertification are less stringent than those for initial certification because it's assumed that if the relieving capacity can be achieved with a more stringent blowdown, it can be achieved with a less stringent (i.e., longer) blowdown as well. It is worth noting that until the 2002 Addenda, each valve sold by the manufacturer or assembler had to be tested to demonstrate the popping and blowdown of the valve. This could be done at a test facility or, if required, on the boiler. In the 2002 Addenda the rules were changed to allow an alternative test that demonstrated only the popping point for valves beyond the testing facility's capability or when the boiler owner preferred not to test the valve on an existing boiler. At this writing, Section I only requires that each valve be tested to demonstrate its popping point. The blowdown control elements must be set to the valve manufacturer's specifications. As a general practice, valve manufacturers and assemblers set the blowdown control elements to avoid getting too close to the minimum blowdown setting of 2%, thus avoiding valve chatter during operation. The setting generally provides for a blowdown in the range of 4% to 7% of set pressure, except for high temperature hot water boilers and once through steam generators which will be about 10% of set pressure. These changes came about because of safety concerns about testing the valves on the boiler as well as concerns about damaging the boiler and other valves when performing the test on an existing boiler. So far, these rules have proven reasonable, providing the relieving capacity required by Section I while apparently meeting the operational requirements of the boiler manufacturers and owners. If, however, the valve purchaser wants a specific blowdown and wants the valve tested to verify the blowdown setting, the testing is generally subject to agreement between the valve supplier and the purchaser.

Section IV requires a controlled blowdown of 2 psi (15 kPa) to 4 psi (30 kPa) for steam boilers. Sections VIII and X have no specified blowdown requirements. Section VIII does, however, require that pressure-relief valves for compressible fluids having an adjustable blowdown construction be adjusted prior to initial certification testing so that blowdown does not exceed 5% of set pressure or 3 psi, whichever is greater,

during the test. This requirement is often misconstrued to be an operating requirement, which it is not. Section XII, unlike Sections I and IV, has established minimum pressure-relief valve closing requirements in terms of percentage of MAWP, not as a minimum pressure in pounds per square inch or percentage of valve set pressure.

Blowdown requirements are summarized in Tables 12.2.

SELECTION OF PRESSURE-RELIEVING DEVICES

When the required relieving capacity has been established and the allowable set pressure and overpressure determined, the pressure-relieving devices can then be selected. The choice of device is limited to those permitted by the particular book section covering the service in question. The first broad category of allowable overpressure protection devices comprises the reclosing pressure-relief devices.

The reclosing pressure-relief device most widely accepted by the various book sections of the Code is the spring-loaded pressure-relief valve. This valve consists of a nozzle attached to an opening in the protected system with a disk held against the open end of the nozzle by a spring. When the system pressure acting against the disk overcomes the spring force, the disk opens and fluid flows from the system. One particular type of spring-loaded valve is the balanced valve, sometimes called a balanced bellows valve, wherein a bellows having an effective area equivalent to the valve seat area is attached to the disk to prevent backpressure in the valve's discharge system from acting on the disk and affecting its opening pressure. Traditionally, spring-loaded valves for boiler or steam application have been called **safety valves**; spring-loaded valves for liquid application have been called **relief valves**; and multipurpose spring-loaded valves that might be used for steam, other compressible fluids, or liquid, have been called **safety relief valves**. None of these terms fully describes the design or function of a **pressure-relief valve**. In many cases, the terms are used interchangeably. The more generic term, pressure-relief valve, has replaced the three definitions in some portions of the Code.

A spring-loaded pressure-relief valve is permitted by all sections of the Code as an overpressure protection device. Operational and construction requirements, however, vary among the book sections. The popularity of this design is due to the reliability of having few moving parts, the repeatability of an opening point controlled by a spring, and the ability of the valve to close when an overpressure condition is reduced to a safe level.

Another type of pressure-relief valve is the **pilot-operated pressure-relief valve**. This is a valve in which the major relieving device or main valve is combined with and controlled by a self-actuated auxiliary pressure-relief valve or pilot. The main valve consists of a nozzle and a disk similar to the spring-loaded valve, except

PRESSURE-RELIEF DEVICE OPERATING REQUIREMENTS				
APPLICATION	ALLOWABLE VESSEL OVERPRESSURE (ABOVE MAWP OR VESSEL DESIGN PRESSURE)	SPECIFIED PRESSURE SETTINGS	SET PRESSURE TOLERANCE WITH RESPECT TO SET PRESSURE	REQUIRED BLOWDOWN
All vessels with exceptions shown below (RR-100a)	10% or 3 psi (20 kPa) whichever is greater (RR-130a)	$\leq$ Design pressure of vessel (RR-120)	Refer to Section VIII Div 1 (RR-112)	Not specified
Exceptions: When multiple devices are used	16% or 4 psi (30 kPa) — whichever is greater (RR-130b)	One valve $\leq$ MAWP, additional valves up to 105% of MAWP (RR-120)		
Additional hazard due to fire	21% (RR-130c)			

TABLE 12.2(d)
SECTION X

PRESSURE-RELIEF DEVICE OPERATING REQUIREMENTS				
APPLICA- TION	ALLOWABLE VESSEL OVERPRESSURE (ABOVE MAWP OR VESSEL DESIGN PRESSURE)	SPECIFIED PRESSURE SETTINGS	SET PRESSURE TOLERANCE WITH RESPECT TO SET PRESSURE	REQUIRED BLOWDOWN
All tanks with exceptions shown below (TR-100)	Not specified	Not specified	For valves: ± 2 psi (14 kPa) up to and including 70 psi (483 kPa) ± 3% over 70 psi (483 kPa) – (TR-200c) For rupture disks: ± 2 psi (14 kPa) up to and including 40 psi (280 kPa) ± 5% of marked pressure above 40 psi (280 kPa) (TR-300a) For pin devices: ± 5 psi (34.5 kPa) for pressures ≥ 30 psi (207 kPa) to pressures ≤ 150 psi (1035 kPa) ± 10 psi (69 kPa) for pres- sures > 150 psi (1035 kPa) to pressures ≤ 275 psi (1890 kPa) ± 15 psi (103.5 kPa) for pressures > 275 psi (1890 kPa) to pressures ≤ 375 psi (2588 kPa) (TR-320b)	Not specified
Category 331 tanks	Not specified	MAWP (1-3.11.1a2)	Same	Not specified
Category 338 tanks	21% of MAWP (1-4.6c1)	≤ 110% of MAWP (1-4.6c1)	Same	Close not lower than MAWP (1-4.6c1)
Category 406, 407, and 412 tanks	Not more than tank test pressure (1-1.8.2h)	≥ 120% of MAWP but not more than 132% of MAWP (1-1.8.2h)	Same	Close at not more than 108% of MAWP (1-1.8.2h)
Special design 406 tanks	Same as 406, 407 and 412 tanks [Vacuum limited to 1 psi (0.07 bar)] (1-2.1d)	The greater of 3.3 psi (0.23 bar) but not more than 138% of MAWP (1.2.1c)	Same	Close at not less than MAWP (1- 2.1c)
Special design 407 and 412 tanks	Same as 406, 407 and 412 tanks (Vacuum limited to 80 & of vacuum design) (1-2.2b and 1-2.3b)	Same as 406, 407, and 412 tanks	Same	Same as 406, 407 and 412 tanks
Cryogenic Portable	20% of MAWP (3-1.7a2)	MAWP (3-1.7a1)	Same	Close at not less than 90% of MAWP (3-1.7a1)
Ton Tanks	Zero. Maximum pressure not to exceed 82.5% of test pressure (4-8)	Fusible plugs function at least at 175°F (79°C) but not less than 130°F (54°C). Other devices set at pressures based on test pressure — 70% to 75% of test pressure (4-8)	Same	Not specified

TABLE 12.2(e)
SECTION XII

that the disk is held in place by system pressure. When system pressure rises above the set pressure of the valve, the pilot senses that pressure and vents the pressure above the disk, allowing the main valve to open. As with spring-loaded valves, the pilot-operated pressure-relief valve is self-operated, using only system fluid as the operating medium. Pilot-operated pressure-relief valves have the advantage that their operation is less influenced by fluid conditions at the valve inlet; they generally can be tested in situ; and a high seating load is maintained up to the opening point of the valve. The valve has more operating parts, however, and because of typically small passages in the pilot, the cleanliness of the fluids on which the pilot-operated pressure-relief valve operates could become a concern. Pilot-operated pressure-relief valves are permitted by Sections I, VIII, and X.

A third type of pressure-relief valve is the **power-actuated pressure-relief valve**. These valves differ from pilot-operated pressure-relief valves in that they require an external energy source provided by electrical, pneumatic, or hydraulic systems and generally operate in response to signals from pressure or temperature-sensing devices. These types of pressure-relief valves offer the benefits of a wide variety of control systems, but have the disadvantage of relying on an external source of power that may fail under emergency conditions. Power-actuated relieving valves are often furnished on drum-type boilers as a convenience to the operators, even though for that type of boiler Section I permits no credit for their relieving capacity. Power-actuated pressure-relief valves are permitted by Section I for use on forced-flow steam generators with no fixed steam and waterline. (See PG-67.4).

The second broad category of allowable overpressure protection devices comprises the nonreclosing devices. The most common nonreclosing device is a **rupture disk** device, which is designed to function by the bursting of a pressure containing disk. The rupture disk is the pressure containing and pressure-sensitive element of the rupture disk device. Rupture disks may be designed in several configurations, such as plain flat, prebulged, or reverse buckling, and can be made of either ductile or brittle material.

A rupture disk is a relatively inexpensive device that, once opened, is not subject to conditions of instability. Also, rupture disks themselves are less likely to leak prior to opening. However, they do not reclose after opening and must be replaced after each overpressure event. In some circumstances, the opening point of some types of disk may be affected by pressure pulsations.

Rupture disks are permitted by Sections I, VIII, X, and XII. Section XII allows rupture disks only when combined with a pressure-relief valve. They may be used as the sole source of pressure relief when permitted by the governing jurisdiction. Section I allows the installation of a rupture disk only under the pressure-relief valve of an organic fluid vaporizer. The rupture disk helps prevent leakage to the environment and protects the valve from the organic fluid, which can polymerize in service and cause valve malfunction. In an unusual departure from normal Section I coverage of new construction only, PVG-12.2 requires yearly removal of pressure-relief valves on organic fluid vaporizers for inspection, repair (if necessary), and testing. When rupture disks are used in combination with pressure-relief valves, an overpressure event causes rupture of the disk followed by opening of the valve. When pressure returns to normal, the pressure-relief valve closes and prevents further loss of system fluid. The space between the rupture disk and the valve must be provided with a pressure gage, a try cock, a free vent, or a telltale indicator, so that pressure cannot build up undetected. A buildup of pressure between the rupture disk and the valve inlet will alter the bursting pressure of the rupture disk.

Other types of nonreclosing devices are permitted for Section VIII Division 1 and 2 use, but not Division 3. These devices are **nonreclosing spring-loaded pressure-relief valves** and **pin devices**. Pin devices include the **breaking pin** and **buckling pin** device, first allowed in the early 1990s for Section VIII, Division 1 use by Code Case 2091. Section XII allows the use of pin devices only in combination with a pressure-relief valve. Pin devices may be the sole pressure-relieving device when permitted by the governing jurisdiction.

The **nonreclosing spring-loaded pressure-relief valve** is designed so that the spring-loaded portion of the device opens at the specified set pressure and remains open until manually reset. Such a device may not be used in combination with any other type of pressure-relief device.

A **breaking pin device** is a nonreclosing pressure-relief device actuated by inlet static pressure. It functions by the failure in tension of a breaking pin that supports a pressure containing or closure member within

the breaking pin device. When set pressure is reached, the breaking pin breaks, allowing the device to open and flow its rated capacity. The pin must be replaced before the device can be reclosed.

A **buckling pin device** is one in which a piston resisting the vessel pressure is held in place by a slender pin in compression. The length and diameter of the pin are closely controlled so that its elastic buckling load in compression can be accurately predicted. When pressure in the vessel reaches set pressure, the pin buckles, allowing the piston to move sufficiently to open a discharge port, thereby relieving the pressure. The pin must be replaced before the device can be returned to service.

The ASME Code normally does not prohibit specific designs. One exception to this rule, however, is the stipulation that a weight-loaded (as opposed to spring-loaded) valve may not be used for pressure relief. A weight-loaded pressure-relief valve is similar to a spring-loaded valve, except that the spring is replaced by a weight. The problem with this type of valve is that any mechanical interference in the valve or tampering with the weight can compromise its pressure-relieving capability. However, such valves are not prohibited internationally and are used for low-pressure vents in the United States and elsewhere. A second prohibited type, in Section IV, is a bottom-guided or wing-guided disk design in which the guidance is provided on the process side of the disk. The concern in this case is possible fouling or sticking of the guide due to the process fluid.

The types of pressure-relieving devices allowed by each book section of the Code are summarized in Table 12.1.

DESIGN OF PRESSURE-RELIEF VALVES

Although the primary emphasis of the ASME Code is on the design of boilers and pressure vessels, pressure-relief devices are recognized as important appurtenances of the vessels. The Code provides guidance for the operational integrity of these devices, but, with the exception of Section III, provides only limited design guidance for them. Most notably (again with the exception of Section III), design rules are not provided for determining wall thickness of pressure-relief valves. Consequently, the manufacturers must look elsewhere for guidance. Manufacturers often use the design bases published in such standards as ASME B16.34, Valves — Flanged, Threaded, and Welding End, and ASME B16.5, Pipe Flanges and Flanged Fittings, or use other methods, from proof testing to design-by-analysis using finite element methods, to establish pressure and temperature ratings.

Design guidance for nonreclosing devices is even more limited in regard to what materials may be used for rupture disk holders and what sampling and testing methods must be used to verify the stamped bursting pressure at coincident temperature.

Mechanical Requirements

The mechanical design rules focus on the operability and reliability of the valve. To ensure the integrity of the spring, for example, the designer must limit the full lift spring compression to no greater than 80% of nominal solid deflection. As an added safeguard, the spring must not exhibit a permanent set of more than 0.5% of free height after being compressed to solid height three times. These rules are intended to ensure that the spring does not relax under load, causing a variation in valve set pressure.

The operating or moving parts of a valve must be free at all times. Thus, drains are generally required below valve seats, to avoid collection of liquids or deposits that might inhibit free operation. Sections I, IV, VIII, and X also require lifting levers that allow a valve to be mechanically operated from time to time to verify that it is free to operate. Except for Section IV valves, the lever must be able to lift the disk when inlet pressure is above 75% of set pressure. Levers on Section IV valves must be able to lift the disk at least 1/16 in. (1.5 mm) with no pressure in the boiler. Levers are required for all Section I and IV valves, and for Section VIII and X valves in steam, air, and hot water [over 140°F (60°C)] service. Many users are concerned about the release of undesirable fluids into the atmosphere, so levers are not generally used for fluids other than

steam, air, and water. The requirement for a lifting device on a pilot-operated pressure-relief valve may be satisfied by providing a connection for applying pressure to the pilot to verify that the critical moving parts are free to move.

Other rules relate to the integrity of external adjustments. After a manufacturer, assembler, or other authorized agent adjusts a pressure-relief valve, the adjustment must be sealed, generally with a lead seal on wire. Except for Section IV valves, the seal must be marked to identify the organization making the adjustment, and the design must be such that the seal has to be broken to change the adjustment.

The structural integrity of most pressure-relief valves is further assured by a Code requirement for the manufacturer to hydrostatically test the primary side of the valves.

Materials

Sections I, IV, VIII, X, and XII of the Code define two categories of materials acceptable for pressure-relief valve construction: one for external pressure containing parts of the device (e.g., the body and bonnet of the valve) and a second for internal parts, such as valve nozzles and disks. In the first category, materials are limited to those normally used for vessel construction, which are listed in the governing book section. The chemical composition, physical properties, allowable stresses, and weldability of these materials are well known. However, the designer of pressure-relief valves must also consider other properties important for proper valve function, such as corrosion resistance of seats, disks, springs, and adjacent sliding surfaces; anti-galling characteristics for sliding surfaces; high strength for valve springs; and erosion resistance for valve seating.

Section I, Division 1 of Section VIII, and Section X also permit the use of some 18 other material specifications for pressure-containing valve parts, under Code Case 1750. This case has evolved as a means of permitting the use of new materials without requiring the valve manufacturer to undertake the extensive and burdensome procedures normally required to qualify material for vessel construction and normally used by the appropriate Code committee to establish allowable design stresses as a function of temperature. Case 1750 thus includes no allowable stresses, leaving the designer to choose his or her own, presumably using book section criteria.

In the second category of materials (for internal parts), the Code permits a much wider latitude, limiting materials to those listed in Section II or in ASTM specifications or those controlled by a specification that provides “control of chemical and physical properties and quality at least equivalent to ASTM standards.” The purpose of this requirement is to help ensure consistent quality of these components.

ESTABLISHING AND CERTIFYING RELIEVING CAPACITIES

Many codes and standards applicable to pressure-relief valves worldwide specify performance requirements similar to those found in the ASME Code, and regulatory bodies may require capacity certification and testing of valves. However, only the ASME Code requires the pressure-relief valve manufacturer to demonstrate performance and relieving capacity of production pressure-relief valves, by a test performed at an ASME-accepted test facility, supervised by an ASME Authorized Observer, and witnessed by a qualified third party designated by the ASME. Performance and capacity testing of pressure-relief valves was first mandated (by Section I of the Code) in 1937, following a program of valve testing sponsored by the National Board of Boiler and Pressure Vessel Inspectors. These tests, conducted in 1935 and 1936, in some cases showed actual discharge capacities significantly less than those claimed by the valve manufacturer.

The procedures used for capacity testing and the formulas used to determine capacity are based on the assumption that compressible flow through the valve is critical (acoustically choked), i.e., it is essentially a function of inlet pressure. For steam flow, the capacity is assumed to follow Napier’s formula, which also states that flow is proportional to inlet pressure. For dry saturated steam above 1500 psi (10 MPa), the Code specifies a correction factor for Napier’s formula. For incompressible flow of nonflashing (subcooled) liq-

uids, the capacity is assumed proportional to the square root of the pressure drop across the valve. Pressure-relief valve capacity certification tests conducted at the relatively low pressures available at test laboratories in the 1930s are still valid today. Extrapolation of valve capacities based on low-pressure tests of small valves to higher pressures and larger sizes continues to be acceptable Code practice.

All ASME pressure-relief valves must be marked by the manufacturer with an ASME Code symbol. Before the ASME Code symbol may be applied to a pressure-relief valve, its relieving capacity must first be certified and then confirmed by tests of randomly selected production valves. This process generally involves an initial or provisional test whereby a number of valves are tested to determine the rated relieving capacity and to demonstrate consistency of valve relieving performance, in accordance with the requirements of the applicable book section. This is followed by periodic testing (initially, and at least every 5 years thereafter) of randomly selected production valves in the presence of a representative of the National Board, which serves as what is known as an ASME-designated organization. (Such an organization meets certain ASME criteria intended to assure appropriate operating and due process procedures.) The ongoing testing verifies that production valves continue to perform as originally certified.

The initial or provisional testing of valves that are to be used on compressible fluids is performed on dry saturated steam, air, or natural gas. For Section VIII use, if the valve is intended for use on steam, at least one of the certification valves must be tested on steam. Valves that are to be used for incompressible fluid service must be tested on water.

Before each test is performed, valve set pressure must be checked for compliance with the applicable book section (i.e., it must meet the opening pressure tolerance). The capacity test is then performed at the allowable overpressure above set pressure specified in that same book section. There is some minor variation in test procedure among the various book sections.

There are three different methods used for certification testing: the **three-valve method**, the **four-valve (slope) method**, and the **coefficient of discharge method**.

The Three-Valve Method. If the intent is to test a single valve design at a single set pressure, three identical valves, all set at the same pressure, are tested to determine capacity. Each of the measured capacities must fall within $\pm 5\%$ of the average of the three capacities. This average capacity is then multiplied by 0.9 to determine the official certified capacity to be stamped on the valve, for this valve design at the particular pressure chosen.

The Four Valve (Slope) Method. This method is used to determine the capacity of a single valve design over a range of set pressures. The four-valve method is also known as the slope method, since there is a straight line relationship between capacity and absolute inlet pressure for compressible fluids and between the log of capacity and the log of pressure drop across the valve for incompressible fluids. In this method, four valves of the same size are set at four different pressures, and the capacity of each valve is determined by test. For compressible fluids, each measured capacity is divided by the absolute flowing pressure to determine a slope, in pounds per hour per psi (kg/hr per MPa). The slope derived from each individual test must fall within $\pm 5\%$ of the average value of slope calculated from the result of all four tests. The rated, or certified, relieving capacity is then determined as 0.9 times the product of the average slope times the (absolute) set pressure plus allowable overpressure. For example, the certified capacity to be stamped on a Section I valve would be $0.9 \times \text{average slope} \times (1.03 \times \text{set pressure} + 14.7)$. For incompressible fluids, the capacities determined from the four tests are plotted on log paper against the differential test pressure (inlet pressure minus discharge pressure), and a straight line is drawn through the four points. Individual points may not depart more than 5% from the straight line. The relieving capacity is then determined from this plotted line. The certified capacity may not exceed 0.9 times the capacity taken from the line. The results of the four-valve method may be extrapolated to cover a larger range of pressures.

The Coefficient of Discharge Method. When a complete line of valves consisting of various inlet sizes, orifice sizes, and set pressures is to be certified, the coefficient of discharge method is used. In this case, three

valves of each of three different sizes (a total of nine valves) are tested, with each valve of a given size set at a different pressure. From each test, a coefficient of discharge is calculated equal to the actual flow measured divided by a theoretical flow determined from formulas appropriate to the fluid being used. Each of the calculated coefficients of discharge must fall within $\pm 5\%$ of an average coefficient of discharge calculated from the results of the nine tests. For sections III and VIII, the average coefficient of discharge is then multiplied by 0.9 to determine the rated coefficient of discharge to be used for calculating the rated relieving capacity of that line of valves. For valves certified per the rules of Section I and IV, the average coefficient is used directly and the 0.9 factor is included in the formula used for calculating the relieving capacity. Over the years, these inconsistent but equivalent methods have been a source of some confusion. In 1997, action was taken to reconcile the two by having all Code sections adopt the version used by Sections III and VIII. Henceforth, the 0.9 factor will be incorporated into the coefficient of discharge.

All provisional tests must be performed at an ASME-accepted test facility that meets the requirements of ASME Performance Test Code PTC 25, Pressure-Relief Devices, and must be supervised by an individual (Authorized Observer) whose qualifications must also meet the requirements of that code. The facilities, procedures, and qualifications of the Authorized Observer must be accepted by ASME on the recommendation of a representative of an ASME-designated organization. (The National Board is the ASME-designated organization when pressure-relief devices are involved). Continued acceptance of the testing facility is subject to review by a representative of an ASME-designated organization within each 5-yr period.

The valves selected for testing must fall within the capacity of the accepted test facility. Valves larger than those actually tested are therefore designed with flow paths geometrically similar to those of the valves actually tested. The results of capacity testing can thus be extrapolated for the stamping of larger valves.

Once the pressure-relief valve capacity has been determined and certified, and before the Code symbol stamp can be applied, two production valves must be selected by a representative of an ASME-designated organization and tested to verify operation and stamped capacity. These tests are performed at an ASME-accepted facility supervised by an Authorized Observer and witnessed by a representative of an ASME-designated organization. Thereafter, two more production valves must be selected and tested within each 5-yr period. Should any valve fail to meet specified performance requirements or the stamped capacity, additional valves must be selected and tested. Two valves are selected and tested for each valve that failed. Continued or unexplained failure may cause the revocation of the manufacturer's or assembler's authorization to use the Code symbol stamp on that particular design of valve.

The valve capacity certification requirements for each of the book sections of the Code are similar. There are other requirements in each of the book sections for pressure-relief devices other than valves (e.g., rupture disks) and for those devices in combination with valves. These requirements are similar to those described for valves.

Test data from the initial or provisional test and the subsequent production test are signed by the manufacturer and Authorized Observer and submitted to the ASME-designated organization for review and acceptance. The rated capacities at various pressures, the rated capacity slope, or coefficient of discharge, as applicable for each valve design are then listed in a book entitled *Pressure-Relief Device Certifications* (NB-18), published annually by the National Board of Boiler and Pressure Vessel Inspectors of Columbus, Ohio. This information is also available on the National Board website and is updated monthly.

Questions are sometimes asked about the so-called derating factor applied to certification test results to determine stamped capacity. There is a perception that a pressure-relief valve could actually pass considerably more fluid than the stamped capacity would indicate. In fact, valves supplied as "non-Code" valves are sometimes stamped with capacities that do not include the derating factor. Nevertheless, there are several reasons to require the use of the 0.9 factor. Individual valves that have been tested as part of the capacity certification program may have demonstrated capacities up to 5% below the average used as the reported test value. This reduces the potential difference between the stamped capacity and the tested capacity of those valves to only 5%. Moreover, it is reasonable to expect that further variation may occur due to normal manufacturing tolerances. Considering the importance of adequate pressure-relieving capacity, the concerned committees chose to apply a conservative derating factor to the reported test value to ensure that actual flow through the device at specified overpressure will always equal or exceed its stamped capacity. However, the designer of

the valve discharge system should recognize the possibility of flow (and resulting discharge forces) larger than those based on rated capacities.

QUALIFICATION OF PRESSURE-RELIEF VALVE MANUFACTURERS

A unique aspect of the ASME Code is a requirement for the manufacturer of pressure-relief valves to demonstrate that its manufacturing, production, and test facilities, and quality control system, will ensure close agreement between the performance of production valves and the performance of the valves submitted for certification. The valve manufacturing control systems must be documented in the manufacturer's quality control manual. That manual is reviewed to ensure compliance with ASME Code requirements. At the present time, the ASME-designated organization whose representatives review the manufacturers' facilities and operations is the National Board of Boiler and Pressure Vessel Inspectors. When the ASME is satisfied with a manufacturer's qualifications, a Certificate of Authorization is issued to the manufacturer, good for 3 yr, allowing the manufacturer to use a Code symbol stamp to mark pressure-relief devices it manufactures as evidence of ASME Code compliance. The review of a manufacturer's manual and system is repeated before its certificate can be renewed. This periodic review of pressure-relief device manufacturers differs from the usual ASME third-party inspection system, in which an Authorized Inspector monitors boiler and pressure vessel manufacturers on an ongoing basis to assure Code compliance. However, the relief device manufacturer's operations are subject to inspections at any time by a representative of an ASME-designated organization, although unannounced inspections are rare in the absence of a specific complaint.

The manufacturer must perform a series of production tests on each pressure-relief valve. Each valve is tested to verify that set pressure and seat tightness meet the requirements specified in the applicable book section. The acceptance standard for seat tightness on steam and water is generally expressed as "no visible leakage." Seat leak tests performed on air must generally meet industry accepted standards.

Production testing of nonreclosing devices in which a component is required to break cannot be used to demonstrate opening of the actual component. Instead, duplicate parts, such as disks for a rupture disk device or pins for a breaking pin device, are manufactured from the same lot of material as the part to be supplied. These duplicates are tested to failure to verify proper operation of the device to be shipped.

Since the mid 1970s, the ASME has also recognized and authorized organizations known as assemblers to assemble and Code stamp pressure-relief valves using only original, unmodified parts obtained from a valve manufacturer. The assembler must assemble, adjust, test, and seal the valves under the same ASME system of oversight and quality control as the original valve manufacturer.

INSTALLATION GUIDELINES

The pressure-relief valve rules of the ASME Code deal primarily with design and functional requirements of pressure-relief devices while providing only limited guidance on their installation. However, a few key installation requirements are specified for pressure-relief devices in each of the book sections. For example:

1. A pressure-relief valve must be installed as close as possible to the vessel or system being protected. This is to minimize inlet pressure drop, which can lead to valve malfunction such as chatter.
2. The opening through all pipe and fittings between a pressure vessel and its pressure-relieving device must have at least the area of the inlet to the pressure-relieving device. This, too, is to minimize inlet pressure drop.
3. A pressure-relief valve must generally be mounted in a vertical position to minimize any potential reseating problems caused by a lateral gravity loading.
4. Discharge lines, and in many cases valve bodies, must be provided with drains to prevent any accumulation of liquid or sediment that could interfere with proper operation.

5. With some few exceptions, no valves may be placed between a pressure-relief device and the vessel it is protecting or on the discharge side, between the device and the atmosphere. Such valves could be inadvertently left in the closed position and thus nullify the overpressure protection.
6. Section I invokes the use of ASME B31.1, Power Piping, for the design of certain boiler piping known as boiler external piping. Power Piping contains Nonmandatory Appendix II, Rules for the Design of Safety Valve Installations. This appendix provides advice on determining loads due to valve discharge and loads on vent stacks, on sizing vents to prevent blowback, and allowable stress criteria for various combinations of loads. It also includes guidance on locating pressure-relief valves away from pipe bends, to avoid flow-induced vibrations in the pressure-relief valve nozzles. Such vibrations have been known to damage the pressure-relief valve internals and cause the valve to malfunction.
7. Section VIII Divisions 1 and 2 contain nonmandatory appendices (M and 9.A, respectively) which provide useful supplementary information and guidance regarding pressure-relief devices. (Section X has a similar appendix.) In some instances, suggested alternatives differ from the mandatory rules of Section VIII; these alternative rules may be used only with permission of the local jurisdictional authorities where the vessel is installed. Among the topics covered are the use of stop valves between a pressure-relieving device and the vessel being protected or on the discharge side of the device, a suggested limit on pressure drop between a vessel and the relief device, design considerations for discharge piping, the use of common discharge headers, advice on differentials between operating and set pressure, the effects of relief valve reaction forces, and guidance on the sizing of pressure-relief devices for fire conditions. A useful list of references is also provided. Section VIII Division 1 contains a mandatory appendix that provides methods for determining the capacity of pressure-relief valves on fluids other than the one on which the valve was officially rated.

PRESSURE-RELIEF VALVES IN SERVICE

Since the ASME Code with few exceptions applies to new construction only, once new pressure-relief devices are installed on a boiler or pressure vessel, adjusted, set, and sealed by the device manufacturer or an assembler, the Code rules no longer directly apply. However, although any subsequent work on these devices is not directly covered by the Code, the local jurisdictional authorities refer to and use the Code rules as guidelines. For example, the National Board under its VR (valve repair) program authorizes organizations of proven capability to service, repair, adjust, set, and seal pressure-relief valves that have been in service. The objective is to restore and maintain the valves so they will continue to function as when new and thus continue to meet the Code rules for newly installed pressure-relief valves on new vessels.

A word of caution is appropriate here. Pressure-relief valves are tested for operation and capacity under optimum conditions: inlet pressure drop and backpressure are minimal and all adjustments on the valve are set and sealed by the manufacturer or an assembler, who is qualified to make these adjustments. When any of these conditions is not as it should be, the relieving capacity and proper operation of the valve can be compromised. That is why the Code requires that all piping and fittings leading to and from pressure-relief valves be adequate to minimize inlet pressure drop and build-up of backpressure. Excessive inlet pressure drop can lead to valve chatter and damage while excessive backpressure may reduce capacity. Tampering with adjustments by unqualified persons can cause failure to open at set pressure, failure to achieve full lift (and certified capacity), failure to reseal properly, and the possibility of damage due to unstable operation. For all these reasons, in the mid-1980s the concerned committees revised the rules to permit valve adjustment only by the manufacturer or assembler of the valve. However, since these rules apply to new construction only, they do not ensure that only qualified individuals will be allowed to adjust these valves in service. It is important that valves in service be maintained so that they will perform as when originally manufactured.

SUMMARY

The overpressure protection rules of the ASME Code are based on an integrated system of accreditation and certification that applies to the different parties involved. These include manufacturers of boilers or pressure vessels, manufacturers of pressure-relief devices, testing laboratories, Authorized Observers who supervise the testing, and a representative of an ASME-designated organization (the National Board) who reviews the facilities, quality control systems, and activities of organizations involved in Code construction. Overpressure protection of boilers and pressure vessels may be provided only by use of devices allowed by the section of the Code applicable to the vessel or system being protected.

FEEDWATER SUPPLY AND WATER LEVEL INDICATION

IMPORTANCE OF FEEDWATER

The designer of a boiler must provide adequate cooling flow of water or steam through the various pressure parts so that they will not exceed their intended design temperatures. Water-cooled furnaces must contain high-temperature combustion gases and cool them sufficiently to pass through closely spaced rows of heating surface without overheating that surface or (for coal-fired boilers) causing slagging problems in the furnace or elsewhere. As discussed in Chapter 3 under Special Concerns, Ferritic alloys (carbon and low alloy steels) are used for water-cooled furnace tubes because of their resistance to chloride-induced stress corrosion cracking. Boiler circulation must be sufficient to cool the furnace walls to temperatures at which ferritic steels have adequate strength and oxidation resistance. Section I has never provided rules for boiler circulation, as the responsibility for functional design has traditionally remained with the boiler manufacturer. However, Section I does have rules that implicitly recognize the serious consequences resulting from the loss of adequate water supply to heat-absorbing circuits critical to the safe operation of the boiler. Firing an inadequately cooled or partially dry boiler can lead to overheating of the pressure parts, with consequent loss of strength and potentially catastrophic failures due to internal pressure. Section I addresses this problem with rules intended to assure the availability of feedwater and the presence of water in the drum.

RULES FOR FEEDWATER SUPPLY

Feedwater supply rules are found in PG-61. For boilers firing solid fuel not in suspension with more than 500 ft² (47 m²) of water heating surface, a redundancy of supply is required, i.e., at least two means of feeding water must be provided. Smaller units are considered to be adequately supplied by a single source. Note that this rule does not apply to boilers firing solid fuel in suspension, such as pulverized coal, or to boilers firing liquid or gaseous fuels if means are provided for shutting off the heat input before the water level reaches the lowest permissible level mentioned in PG-60.1.1. In such cases, the fuel in the furnace is consumed almost immediately after the fuel supply is stopped and the problem of significant overheating is avoided. Another concern addressed in PG-61.1 is that the feedwater system must have adequate supply pressure to maintain flow to the boiler under all conditions. This is accomplished by specifying that each source of feeding be capable of supplying the boiler at a pressure 3% higher than the highest setting of any pressure relief valve on the boiler. Thus, feedwater would presumably continue to flow into the boiler even when it is operating at a pressure sufficient to lift the safety valves.

Boiler damage due to overheating can also occur if a particular firing method leaves an inventory of burning fuel in the furnace when the feedwater supply is lost or interrupted. This is a concern for stoker fired boilers and fluid bed boilers, where a bed of combustible material remains when the boiler is tripped due to an electrical outage or mechanical failure and feedwater flow stops. For such boilers and for boilers whose setting or heat source can continue to supply sufficient heat to cause damage to the boiler if the feed supply is interrupted, PG-61.1 requires that one means of feeding shall not be susceptible to the same interruption as the other. Each source must be able to provide sufficient water to prevent damage to the boiler. The intent is for the designer to consider potential failure modes and provide an independent backup feedwater system to cool the pressure parts that otherwise could be overheated by the setting or by any burning fuel that remains in the furnace. The backup feedwater source is only required to provide sufficient water to prevent damage to the boiler. The determination of that quantity is left to the boiler designer, since he or she is best qualified to make that decision. In 1981, BPV I elaborated its position on minimum required feedwater flow and supply pressure in Interpretations I-81-15, I-81-20, and I-81-25, noting that Section I does not define this minimum and placing on the designer the responsibility for providing sufficient feedwater flow to satisfy all requirements of Section I. Here are those Interpretations:

Question: Since requirements for the flow capacity of the feedwater source are not given in PG-61.1, is it the responsibility of the designer of the feedwater system to provide arrangements that establish the feedwater flow required to satisfy the pressure requirements of PG-61?

Reply: Yes.

Question: The rules of PG-61.1 require that each source of feedwater be capable of supplying water to the boiler at a pressure 3% higher than the highest setting of any safety valve on the boiler. Does the phrase "at a pressure" apply to the pressure at the feedwater pump outlet or to the pressure in the boiler drum?

Reply: The feedwater pressure requirements in PG-61.1 apply to pressures in the boiler drum, not to the pressure at the feedwater pump outlet.

Question: Is the total capacity of the feedwater source based on the maximum process steam requirements, or on the maximum boiler evaporation?

Reply: Section I rules do not address the capacity requirements for the boiler feedwater source.

Question: What is the minimum flow rate required to satisfy the requirements of PG-61.1?

Reply: Section I does not define the minimum flow rate required to satisfy the requirements of PG-61.1. It is the responsibility of the designer to provide for sufficient feedwater flow to satisfy all requirements of Section I.

Interpretation I-89-57 dealt with required feedwater flow capacity for a forced-flow steam generator with no fixed steam or waterline:

Question: When determining the required feedwater flow for a forced flow steam generator with no fixed steam or waterline, does the "maximum designed steaming capacity" in PG-61.5 refer to the flow of steam through the boiler with its safety valves fully open?

Reply: No.

A number of inquiries have been received about feedwater supply for boilers firing fuel partially in suspension. Interpretation I-86-62, Boilers Firing Solid Fuel, clarified this situation:

Question: Does the term "solid fuel not in suspension" used in PG-61.1 refer to any portion of the fuel which is not burned in suspension?

Reply: Yes, it applies to that portion of the fuel burned in any type of bed in the furnace.

Question: Do the requirements in PG-61.1 (for boilers fired by fuel not in suspension) to have two means of feeding water, one of which is not susceptible to the same interruption as the other, apply if the solid fuel is burned partially in suspension and partially in a bed?

Reply: Yes.

Question: For boilers that are fired with solid fuel not in suspension, do two electrically driven feed pumps, each supplied with power from independent electrical sources, meet the requirements of PG-61.1?

Reply: Yes.

A 1986 inquiry sought further guidance regarding redundancy of the feedwater lines themselves. This was provided in Interpretation I-86-18:

Question: When a boiler requires two means of feeding water under PG-61, are two separate feedwater lines to the boiler required?

Reply: No.

Question: Are the valves in the boiler external feedwater piping required to be the same size as the boiler connection and boiler external feedwater pipe?

Reply: No.

It is clear that Section I requires a backup feedwater supply in the several cases just described. In 1995 an inquirer asked whether that philosophy extended to the normal operation of the boiler. Interpretation I-95-22, Redundancy of Feedwater Supply, advised as follows:

Question: A boiler firing solid fuel not in suspension is provided with two independent means of feeding water not susceptible to the same interruption, as required by PG-61.1. Does Section I prohibit the continued operation of the boiler following the loss of one of the independent means of feeding water?

Reply: No. PG-61.1 establishes the feedwater arrangements which must be provided. Section I as a construction code does not impose additional rules covering boiler operation.

During committee discussion of this inquiry, it was noted that requiring shutdown of the boiler on loss of one of the two required sources of feedwater would be akin to driving no further after experiencing a flat tire and mounting the spare. It was also noted that the availability of a single backup source of feedwater would take care of most situations, such that the loss of the remaining source would be a rare occurrence, with little impact on the life of the boiler, as measured by cumulative creep damage.

There is one exception to the PG-61.1 rule requiring backup feedwater supply for boilers firing solid fuel not in suspension or whose setting or heat source could damage the boiler if the feed were interrupted. The exception concerns what are called black liquor chemical recovery boilers used in the Kraft pulp and paper industry. They operate with a hot, molten smelt bed in the boiler, a bed which in theory could cause damage to the boiler on loss of feedwater. However, the real danger with these boilers comes from the possibility of water leaking into the smelt bed and causing a violent explosion. Accordingly, the industry developed and uses leak detection methods that on finding a leak stop the feedwater and trigger an emergency rapid drain procedure. In the course of using this system, it was found that the boilers were sustaining very little damage and could thus be exempt from the rule requiring a continuing supply of water. This was affirmed by Interpretation I-83-03:

Question: Is a black liquor chemical recovery boiler equipped with an emergency rapid drain system required to have a steam driven feedwater pump to satisfy the provisions of PG-61.1?

Reply: No, since it has been demonstrated that the heat source of a black liquor chemical recovery boiler equipped with an emergency rapid drain system does not supply sufficient heat to damage the boiler if feedwater is interrupted, it is not required that one of the feedwater pumps be steam driven.

(Note: The 1983 requirement for a steam-driven pump was subsequently changed to a requirement that one means of feeding not be susceptible to the same interruption as the other.)

Another potential exception to the two sources of feedwater rule appeared in Code Case 2160, which covered certain types of fluid bed boilers. The concern about fluid bed boilers involved the possibility that the

bed, which contains fuel and limestone, might continue to evolve sufficient heat to damage the boiler after it was tripped on loss of feedwater. Case 2160 provided controls and safeguards intended to ensure that this would not happen. It also included a requirement that the designer provide calculations, signed by a Professional Engineer, demonstrating that even under the most severe conditions no part of the boiler will overheat to the point that the allowable stresses are exceeded. To the best knowledge of the Committee, this Code Case was never invoked and was subsequently annulled. As of this writing there has been no renewed interest in pursuing a similar case for fluid bed boilers.

TOWER MOUNTED SOLAR FIRED BOILERS

At this writing, the latest and, perhaps, one of the more interesting inquiries regarding the rules for feedwater supply involved a tower mounted solar fired boiler. As explained to BPV I, solar fired boilers are heated by concentrated solar radiation received from a multitude of electro-mechanically aimed mirrors surrounding the water heating surface. In this particular case, the boiler was a natural circulation boiler having more than 500 ft² (47 m²) of heating surface. The fuel (solar flux) was shut off by repositioning the mirrors such that the focus was off the heat absorbing target. This repositioning process took from 60 to 90 seconds to complete. Because the heating surface exceeded the 500 ft² (47 m²) limit of PG-61, the fuel could not be categorized as solid, gaseous, or liquid, and could not be described as in suspension, the inquirer was requesting a Code Case to permit this type and size of solar fired boiler to be provided with a single means of feeding water. After considering what appeared to be a somewhat lengthy fuel cut off (mirror repositioning) time and the safeguards provided to address this and other concerns, BPV I approved and issued in December, 2009, Code Case 2635, Single Feedwater Source for Solar Fired Boiler. The Code Case permitted the described boiler to be provided with a single means of feeding water provided:

- Heat input would be automatically shut off in the event of loss in feedwater supply, or prior to the water level reaching the lowest permissible level per PG-60.
- There is sufficient water in the drum at the lowest permissible level that initiates shutdown to prevent damage during the shutdown process;
- The heat input is shut off in the event of failure in the main power supply to the heating control system;
- There is a backup means of automatically shutting off the heat input in the event of control system failures; and
- The amount of residual flux concentrated on the boiler after shutdown does not result in the boiler parts exceeding their design temperature limits.

While still not a common type of boiler, a tremendous amount of research and development is being put into solar fired steam generators. In response to the growing interest in solar energy, BPV I established in 2010 a new subgroup, Subgroup on Solar Boilers, charged with reviewing and providing comments on any proposals relating to solar boilers within Section I. It is fair to say that this Code Case will soon be incorporated into Section I.

FORCED-FLOW STEAM GENERATORS

Once-through forced-flow type boilers with no fixed steam and waterline differ from natural circulation units in that the feedwater flow rate is directly proportional to steam flow and is not controlled by boiler drum level. Since no drum or drum level indication is available, the operator has no visible assurance that sufficient water is being supplied to the boiler. These units depend on control instrumentation and interlocking alarms and trips to protect against loss of feedwater supply. For such boilers, Section I simply requires that a source of feedwater be available to the boiler at a pressure not less than the expected maximum sustained pres-

sure at the boiler inlet corresponding to operation at maximum designed steaming capacity with maximum allowable working pressure at the superheat outlet. The determination of this pressure is left to the boiler manufacturer.

LOW WATER LEVEL FUEL CUTOFFS

The exception to the requirement for a second feedwater supply system for boilers firing gaseous, liquid, or solid fuels in suspension applies when means are furnished for shutting off the fuel (or heat input) before the water reaches the lowest permissible level. Typical fuels included in this category are natural gas, oil, or pulverized coal. The fuel shutoff is normally referred to as a low-water fuel cutoff. While required for certain electric and miniature boilers (PEB-16, PMB-17), Section I does not mandate such fuel cutoffs for all boilers. They are, however, routinely furnished on large boilers as well.

WATER LEVEL INDICATION

Rules governing the provision of water level indicators on a boiler are found in PG-60. This paragraph also covers water columns and pressure gages and the connections between these various appurtenances and the drum. Note that this connecting piping falls in the category of boiler external piping, and its design must follow the applicable rules of ASME B31.1 (see Chapter 5).

Low water level is often responsible for pressure part failures because, in most large boilers, circulation is dependent on the pressure head of water in downcomers and low water directly reduces that head. Without adequate circulation, pressure parts are subject to overheating and premature failure. Therefore, every boiler must have a water gage glass. Because knowledge of correct water level is so important to the safe operation of the boiler, PG-60 provides for redundancy in drum water level measurement for boilers operated at pressures over 400 psi (3 MPa), by requiring provision of two water gage glasses. (Like many others in Section I, this is an arbitrary but not unreasonable rule.)

For many years, PG-60 stated that for power boilers with MAWP at 900 psi (6 MPa) and above, two remote level indicators could be provided instead of one of the two required gage glasses. Then, when both remote units were in reliable operation, the remaining gage glass could be shut off, but had to be maintained in serviceable condition. In 1990, a boiler manufacturer asked that the 900 psi (6 MPa) threshold for substituting two remote level indicators for one of the two required gage glasses be lowered to 400 psi (3 MPa). There was nothing magic about 900 psi (6 MPa), and after some consideration, BPV I approved Code Case 2109 to permit use of two remote level indicators for one gage glass at 400 psi (3 MPa), which is at the bottom of the pressure range that normally requires a second gage glass. After several years of satisfactory experience, the case was incorporated, simply by lowering the 900 psi (6 MPa) threshold to 400 psi (3 MPa). This change appeared in the 1996 Addenda.

The provision of two remote level indicators for one of the two water gage glasses normally required means that the second gage glass need not be furnished at all. This was confirmed in response to a 1982 inquiry answered by Interpretation I-83-13, Gage Glass Requirements:

Question: For a boiler whose design pressure is 900 psi or above, PG-60.1.1 permits the provision of two remote level indicators for one of the two gage glasses normally required. Does this mean that the boiler may be furnished with only a single gage glass, which may then be shut off when both remote level indicators are in reliable operation?

Reply: Yes, but note that the single gage glass must be maintained in a serviceable condition.

A traditional operating rule is that a boiler should never be fired when there is no water in the gage glass. Section I stipulates that the lowest visible part of the gage glass shall be at least 2 in. (50mm) above the level at which overheating damage can be expected. Thus, if water is visible in the glass, there is always some

margin against overheating. The Code leaves it to the boiler manufacturer to determine the level at which overheating damage can be expected. This was explained in 1992, by Interpretation I-92-50, Lowest Permissible Water Level:

Question: Does Section I provide a definition of the lowest permissible water level as referenced in PG-60.1.1?

Reply: No. PG-60. 1.1 requires the boiler manufacturer to determine the lowest permissible water level.

When a direct reading of gage glass water level is not readily visible to the operator in the area where immediate control actions are initiated, two dependable indirect indications must be provided, either by transmission of the gage glass image or by remote level indicators. In the 1991 Addenda, after a trial period by means of Code Case 1897 showed the method to be reliable, BPV I added a provision to PG-60 stating that transmission of a gage glass image to the operator (in the area where he could initiate immediate control actions) by means of fiber optic cable was permitted. This was allowed only when no electrical modification of the optical signal was employed. Such transmission is considered to be direct reading of gage glass water level. The committee felt that electronic black boxes would not provide the same reliability as a directly transmitted optical signal along a fiber optic cable. That is also why the committee has so far refused to accept as the equivalent of a direct reading gage glass a number of very clever devices that base their water level readings on the large difference in electrical conductivity between water and steam. These devices may be used as remote indirect level indicators only. The committee responded to a request to permit the use of such devices as the equivalent of a gage glass in Interpretation I-86-2, Boiler Water Level Indicators:

Question: In the case of power boilers with all drum safety valves set at or above 900 psi, may a new technology level indicator be substituted for the remaining gage glass when two remote level indicators are used in lieu of the other gage glass?

Reply: No.

Note that devices using this new technology may be used as remote indirect level indicators, even if BPV I does not consider them the equivalent of a gage glass for simplicity and reliability. Devices using differential conductivity of steam and water have achieved a greater measure of acceptance in Europe.

Since Section I does not clearly define a remote level indicator, one inquirer wanted to know whether a low water alarm and trip indication would serve the purpose. In 1987 under the heading Water Level Indicators, the committee issued Interpretation I-86-50:

Question: Is a direct reading water level gage available to a roving operator considered to be readily visible to the operator in his working area?

Reply: No.

Question: Is a low water alarm and trip indication available to the operator in his working area considered to be a dependable indirect indication of boiler water level?

Reply: No.

A more successful attempt to determine whether a device could serve as a remote water level indicator was answered in late 1994 by Interpretation I-95-04:

Question: May a pressure- and temperature-compensated differential pressure drum level transmitter with a remote readout be considered a remote level indicator?

Reply: Yes.

Other safety rules related to water level control apply to the installation of the gage glass and its appurtenances. For example, shut-off valves on the gage glass connections must have an outside-screw-and-yoke or a lever-lifting type of operating mechanism that indicates whether the valve is open or closed. The rules also require through-flow valve construction to prevent stoppage by deposit of sediment and to ease cleaning.

There is also a rule essentially limiting the type of connections to piping between a water column or gage glass and the drum to those used for water level indication. This rule is to minimize the possibility that activation or failure of another type of device connected to that piping could cause a false reading of water level. Since the water level reading instruments base their readings on a differential pressure of only a few inches of water, any sudden flow or other system disturbance could disrupt them.

PG-60 also provides rules for the minimum size of piping and fittings for water columns, gage glasses, pressure gages, and related components.

When the use of computers became more common, some boiler operators wanted to send signals from instrumentation directly to a computer for reading on a monitor. This led to a concern about continuous display of water level. In 1993 in response to an inquiry, the committee issued Interpretation I-92-63, Continuous Display of Remote Water Level Indication:

Question: If a remote computer terminal is used as one of the two remote level indicators required by PG-60.1.1, may that remote computer terminal display drum water level on demand rather than continuously, when the single gage glass is in service and is readily visible to the operator in the area where immediate control actions are initiated?

Reply: Yes, provided the second remote level indicator is displayed continuously.

This reply is consistent with the principle that a boiler whose MAWP is 400 psi (3 MPa) or more should have two independent and reliable means of drum water level indication readily visible to the operator in his or her working area, where the operator can take any necessary control action to correct a water level problem. The fact that one gage glass was readily and continuously visible to the operator was the key to this reply, and distinguishes it from the situation described in the following interpretation.

In 1995, in response to a similar inquiry, the committee issued Interpretation I-95-07, Remote Level Indication on Computer Monitor.

Question: May a power plant distributed digital control system (DCS) with cathode-ray tube (CRT) screens providing graphic drum water level displays in the control room be considered to provide an independent remote level water indication in accordance with PG-60.1.1?

Reply: Yes. Note that two such independent displays are required in order to omit one of the two normally required gage glasses for boilers whose MAWP is 900 psi or greater.

(Note by authors: The 900 psi (6 MPa) threshold was lowered to 400 psi (3 MPa) in the 1996 Addenda, as related above.)

Question: May a power plant distributed control system (DCS) be considered to provide an independent remote level indication as described in PG-60.1.1 if the displays are interruptible, noncontinuous displays which may require a keystroke to become visible?

Reply: No.

Another type of water level indicating device that, during the early 1990s, had been the subject of a number of inquiries uses an internal magnetic float that provides an external indication of water level. Although such devices would appear to be simple and reliable, the committee had concerns about not being able to see the water level, as well as the possibility that the float might somehow get stuck or that another magnet could be used to cause an erroneous external level indication. However, the devices were considered acceptable as remote water level indicators. In 1993, in response to an inquiry, the committee issued Interpretation I-92-69, Magnetic Level Indicator:

Question: May a magnetic level indicator be used to provide an indirect reading of water level as permitted by PG-60.1.1?

Reply: Yes, provided all other requirements of this Section are met.

(Note by authors: This last proviso, that “all other requirements of this Section are met,” is a time-honored but unnecessary piece of advice. It should go without saying that Section I requirements must be met. This

may have been added to satisfy concerns that permission was being granted to use such nonmagnetic material as austenitic stainless steel in a water wetted service. See further discussion about this, below.)

In response to a related inquiry, in 1994 the committee issued Interpretation I-92-96, Magnetic Level Gage as Remote Level Indicator:

Question: Is a magnetic level gage which provides a local, indirect visual indication of the boiler drum water level considered to be a gage glass as required by PG-60.1.1?

Reply: No.

Question: Do PG-60.1.1 and PG-60.2.6 (Note: the latter paragraph is now PG-60.3.8) permit the installation of a magnetic level gage on the piping between a water column and a gage glass, regardless of boiler maximum allowable working pressure?

Reply: Yes.

In spite of these and other interpretations regarding the acceptability of magnetic water level indicators, there were some committee members and, more important, jurisdictional authorities that questioned whether the devices met Section I rules regarding use of austenitic stainless steels in water wetted service. (It is likely that some believed that the interpretations implied that use of such material was acceptable, thus being another example of “rules by interpretation.”) Until the 2007 Addenda, PG-12, Gage Glass Body and Connector Materials, merely stated that austenitic stainless steels could be used for the body and connector materials. Some believed this restricted the use of such material to small fittings and the gage glass body itself while others believed PG-12 permitted the use of austenitic stainless steels for the body of such devices as magnetic water level indicators. These differing opinions made it difficult for manufacturers, owners and Code enforcement authorities to decide whether to permit the use of magnetic water level indicators on new boilers.

Major revisions to PG-12 and PG-60 were included in the 2007 Addenda to provide rules governing the use of magnetic water level indicators and the materials permitted to be used for the devices. PG-60.1.1.4 now explains that a magnetic water level indicator may be used as an independent remote level indicator provided the device meets the requirements of PG-12.2, the design and construction includes provisions for easy cleaning and maintenance, and that the device manufacturer’s restrictions regarding use within specified ranges of temperatures and pressures are satisfied. PG-12.2 explains that magnetic water level indicators may be used on boilers not exceeding 900 psi (6 MPa) MAWP. The devices must also meet the rules of PG-27, Cylindrical Components Under Internal Pressure, and the material restrictions noted in PG-9.1.2 and PG-12.3. When making the changes, BPV I was careful to direct the reader’s attention to the PG-5.5 footnote which explains that, for successful use of austenitic stainless steel in water wetted service, applied stresses must be kept to a minimum and water chemistry must be under continuous control.

Sometimes when a water gage glass is at some distance away from the operator in the control room, it is possible to install a system of mirrors that will provide an image of the gage glass water level. The committee has established that it considers such means the equivalent of direct reading of the gage glass, by Interpretation I-92-15, Water Level Indicators:

Question: Is the viewing of a gage glass via a system of mirrors considered direct reading of gage glass water level?

Reply: Yes.

WATER COLUMNS

There is sometimes confusion as to what Section I means by the term **water column**. A water column is a vertical vessel connected to the drum by two horizontal connections located in such a way that the lower connection is in the water space and the upper connection is in the steam space of the drum. The level in the water column provides a calmer environment than the inside of the drum, but it still follows the movement of drum water level. Gage glasses can then be mounted on the water column, where they can obtain a steadier water level reading than if they were mounted directly on the drum.

There have been a few Interpretations about water columns. One of these, I-86-07, was issued under the title Materials for Water Columns, although it dealt with broader issues:

Question: *May a water column for use on a power boiler be designed as a standard pressure part?*

Reply: *Yes. See PG-11 and PW-42.*

Question: *May a water column for use on a power boiler be constructed of SA-36 for the nozzles or body?*

Reply: *No. SA-36 material may not be used, except as permitted in PG-13.*

Question: *May a water column for use on a power boiler be constructed using standard piping components and/or individually designed parts, as permitted by the rules of Section I?*

Reply: *Yes.*

Question: *May a water column for use on a power boiler be designed to the rules of Section VIII?*

Reply: *No.*

The prohibition mentioned in the reply on the use of SA-36 for other uses than those permitted in PG-13 is based on a long-standing and perhaps justified belief on the part of some members of the committee that the quality of structural materials such as SA-36 is not as good as that of materials manufactured specifically for withstanding pressure. This can be seen in the Table 1-100, Criteria for Establishing Allowable Stress Values for Tables 1A and 1B of Section II, Part D. In the setting of allowable stresses for pressure retention applications for what are called ferrous materials of structural quality, a factor of 0.92 is applied to the stress as normally derived, i.e., an arbitrary penalty of 8% is imposed. Given modern steel-making practices, that penalty may no longer be justified; however, it is not likely to be dropped any time soon, especially as more steel is imported from producers whose long-term record of quality control may not be known.

A somewhat related Interpretation issued in 1988 as I-89-06 dealt with welding requirements for gage glass bodies. The questions and replies would be equally applicable to water columns, since they are both Section I appurtenances that can be furnished on the same basis.

Question: *Are gage glasses considered to be part of the boiler proper as defined in Fig. PG-58.3.1?*

Reply: *No, they are part of the Boiler External Piping, subject to the rules of PG-60.*

Question: *May welded gage glass bodies be provided under the requirements of PG-11.3 by a manufacturer who does not possess a Section I Certificate of Authorization?*

Reply: *Yes.*

Question: *Must the welding for gage glass bodies, complying with a manufacturer's standard, meet the requirements of PG-11.3? (Note by authors: PG-11.3 calls for welders and weld procedures to be qualified in accordance with PW-26 through PW-39, essentially the full qualification normally required for Section I construction.)*

Reply: *Yes.*

CREEP AND FATIGUE DAMAGE DURING BOILER LIFE

INTRODUCTION

The Foreword to Section I states that the objective of the Section I rules is “to afford reasonable protection of life and property and to provide a margin for deterioration in service so as to give a reasonably long safe period of usefulness.” Sooner or later, almost all equipment wears out, and boilers are no exception. The factors that cause the gradual deterioration of a boiler are many. Among them are erosion and corrosion, which cause a gradual wastage and thinning of pressure parts. Two other significant factors that can limit the life of a boiler are creep and fatigue, processes that can cause progressive deterioration of material properties without wastage and thinning. This deterioration is characterized as creep damage or fatigue damage. For practical purposes when discussing boilers, it can be said that creep damage occurs only at elevated temperature, about 700°F (370°C) and above for carbon and low alloy steels and 800°F (425°C) and above for the high alloy steels typically used in superheater construction. Fatigue damage can occur over the entire range of boiler operating temperature, but as will be explained later, components in elevated-temperature service are more susceptible to fatigue damage. These two damage mechanisms are discussed separately, but their effects are additive.

CREEP

In our everyday experience, metals such as steel are firm, unyielding solids. In courses on elementary strength of materials, we learned that steel deforms elastically under load, following Hooke’s law. For steels at room temperature, strain is a function of stress only. For example, if a load was placed on the end of a cantilever beam, the measured deflection would remain constant, whether measured when the beam was first loaded, or the next week, or the next year. That is, the deflection is independent of time. For certain other solids, and for many metals at elevated temperature, this is not the case. These materials are found to undergo a slow plastic deformation under stress, a process known as creep. Glass creeps at room temperature, but very slowly. This was confirmed when the thickness of 1000-yr-old monastery window panels was measured; they were found to be thicker at the bottom than at the top, showing that the glass had slowly deformed, or flowed, under the influence of gravity. Experiments in the 19th century showed that lead creeps at room temperature. Steels such as those used in boiler construction are known to creep at elevated temperature.

The temperature at which creep begins defines the bottom of the creep range — about 700°F (370°C) for carbon and low alloy steels and about 800°F (425°C) for high alloy steels such as the austenitic stainless

alloys. Increasing alloy content raises the temperature at which creep begins. As a broad rule of thumb, this temperature is about one-fourth of the melting temperature, expressed on an absolute temperature scale. Much careful experimentation in the 20th century has been used to measure and predict the elevated-temperature creep behavior of structural steels, but there are as yet few theories that can accurately describe this behavior, except for conditions of constant temperature and stress. It is very difficult to predict creep behavior under varying temperatures and varying multiaxial states of stress. As a practical matter, it is also very difficult for the designer to predict with confidence the actual temperature and stress state a component may experience during its service life.

Typically, boiler steels are tested to creep failure, or creep rupture, under constant load at constant temperature using dead weight testing machines under very careful temperature control, since creep rate is very sensitive to temperature. Stress and temperature are chosen for each test to yield useful information within a reasonable time. Both elongation and rupture time are recorded. Results are needed from less than 100-hr rupture time to several hundred thousand hours. (Boiler components in service 80% of a 30-yr life might spend over 200,000 hr under creep loading conditions.) Figure 14.1 shows the results of a typical creep test at constant load and temperature, with creep strain plotted as a function of time. This classic form of creep curve is composed of three parts, illustrating what is described as primary (stage I) creep, followed by a generally longer period of secondary (stage II) creep, and finally tertiary (stage III) creep, which culminates in stress rupture. From microstructural examination of creep specimens at various stages of the creep process, increasing damage can be recognized, as illustrated on Fig. 14.2. Voids begin appearing on the grain boundaries somewhere in the second stage. These voids eventually link together, finally forming microcracks. The remaining uncracked load paths must then carry additional load, and the creep damage mechanism accelerates, with the formation of larger cracks finally leading to failure. These various damage stages are sometimes used in remaining-life assessments of components to determine fitness for continued service.

Designers need to be able to predict creep rupture behavior without waiting for the completion of tests that could take many years, and fortunately researchers have discovered that for a given stress level, there is a certain equivalence between time and temperature. Thus creep rupture tests can be shortened by conducting them at higher temperatures. Perhaps the best known creep life predictive methods are those developed by two researchers named Larson and Miller.

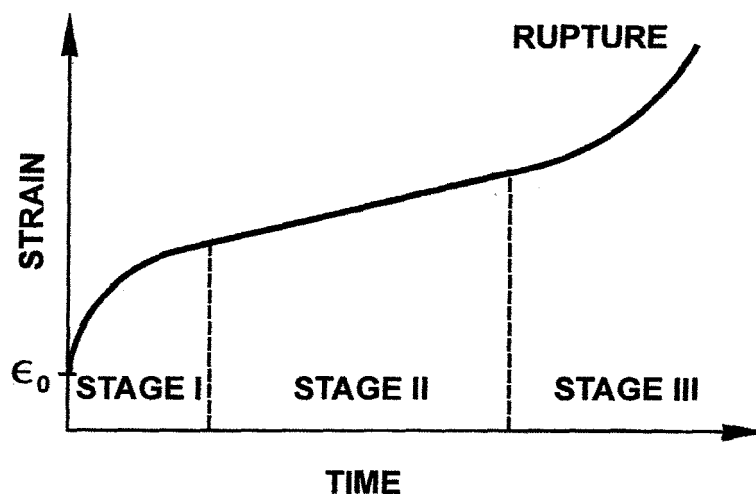


FIG. 14.1
STRAIN IN CONSTANT STRESS CREEP TEST
(Initial Elastic Strain ϵ_0 and Three Stages of Creep are Shown.)

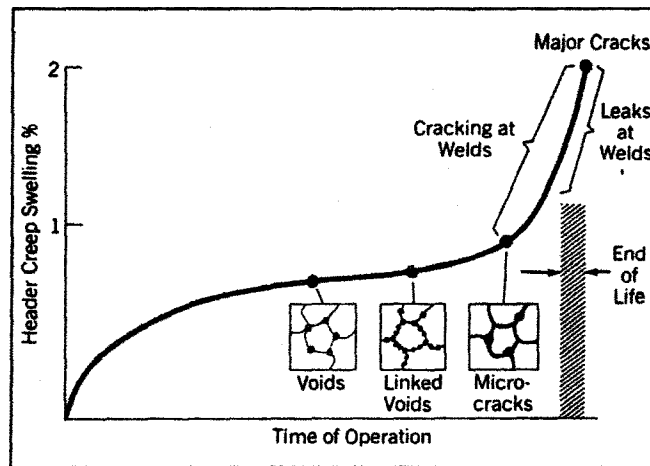


FIG. 14.2
PROGRESSION OF MICROSTRUCTURAL DAMAGE DURING COMPONENT LIFE
(REPRODUCED FROM NEUBAUER AND WEDEL (1983))

The results of the creep tests can be plotted in a number of useful ways, some of which are used to determine stress-to-produce rupture in 100,000 hr, one of the factors used in setting the allowable stresses described in Chapter 15. One typical plot is that shown as Fig. 14.3, a stress versus time-to-rupture plot for 2½Cr-1 Mo steel, a common superheater alloy. (This plot is taken from Subsection NH of Section III, which covers methods of elevated-temperature design of nuclear power plant components. Subsection NH is the most comprehensive Code reference on that subject and is recommended for those interested in further study of elevated-temperature design methods. Before their appearance as Subsection NH in the 1995 Addenda to the Code, these design rules were found in a famous nuclear Code Case, Case N-47.) Note that Fig. 14.3 is a log-log plot, with temperature as a parameter. At given temperatures, the stress-versus-time relations are seen to be straight lines. A little study shows how very strong the influence of temperature is; just a 50°F (25°C) increase causes rupture life to shorten dramatically. For example, Fig. 14.3 shows that at a stress level

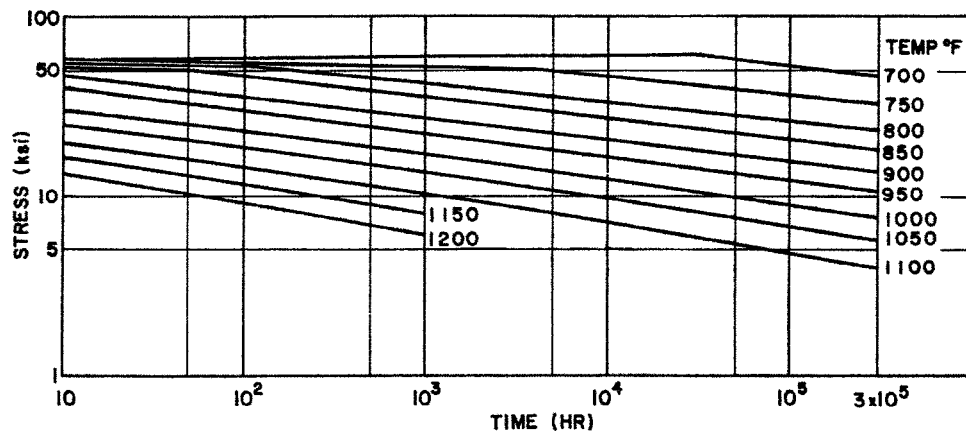


FIG. 14.3
2½ CR-1Mo — 100 PERCENT OF THE MINIMUM STRESS-TO-RUPTURE
(REPRODUCED FROM ASME SECTION III)

of 10,000 psi, the creep rupture life shortens by a factor of about five when the temperature increases from 1000°F (540°C) to 1050°F (565°C).

One way to assess creep damage is to use a so-called **linear damage rule** (also called Robinson's rule), which can be illustrated by use of Fig. 14.3. Suppose a number of steady state operating conditions are anticipated for an elevated-temperature component, in which both stress, time of loading, and temperature are known. The creep damage accumulated during each of these time periods is assumed to be linear with time and is found in the following way. The rupture life for each specified stress and temperature condition is determined. For example, suppose for one of these conditions that the predicted life is 50,000 hr, and the condition is anticipated to last 5000 hr. The cumulative damage during this condition is then defined to be 5000 hr divided by 50,000 hr, or 10%, i.e., 10% of the creep life would be used up by this operating condition. The designer seeks to keep the sum of the cumulative damage due to all anticipated operating conditions less than 100%. If he or she does not, this method would predict creep failure of the component during its service life. Unfortunately, the method is not so simple or accurate as it first might seem, because it is difficult to determine accurately past or future operating conditions (stress, time, and temperature) and also because there is considerable scatter in the data used to develop creep rupture curves. This method can be a useful tool, however, for assessing such things as damage from a short-term temperature excursion. Note also that fatigue damage is additive to creep damage, and the two damage mechanisms interact to accelerate the process of component life expenditure at elevated temperature. This phenomenon is called **creep-fatigue interaction**.

Creep considerations are important when designing boiler components such as superheater tubes, superheater outlet headers, and main steam piping, which typically operate in the creep range and are potentially subject to failure modes involving creep, such as swelling and sudden creep rupture. A creep rupture differs markedly from a tensile rupture at room temperature. In a room temperature test, a steel tensile specimen is subjected to increasing load, it yields, strain hardening takes place, and finally after the load is increased to about twice the yield strength, the specimen necks down and ruptures. Elongation at failure might be 25% or more. In this relatively fast tensile test, the deformation takes place by slip along planes in the grains of the metal and by what is described as ductile void coalescence, with transgranular failure occurring at high total strain. In a creep rupture test, a constant load is imposed and maintained (usually only a fraction of the yield load), while the temperature is kept constant at some elevated value, for example 1100°F (595°C). After a long time, and at some relatively small strain, perhaps only 1% or 2%, the specimen suddenly ruptures. In this slow creep test, failure takes place intergranularly, by the accumulation of grain boundary voids, at low total strain. (Whether a material fails transgranularly or intergranularly depends on a complex interplay among stress, strain rate, and temperature.) The specimen is no longer capable of carrying a load which it formerly carried, even though the load was well below the short-term yield strength of the metal.

All Code allowable stresses at elevated temperature are chosen with significant margins against creep failures, as explained in Chapter 15. However, it should be recognized that components that are stressed at elevated temperature have a finite life, and that this life is slowly being expended. This is particularly pertinent when life-extension studies are undertaken.

FATIGUE

Fatigue is commonly understood to mean the behavior of a material under the repeated application of stress or strain. The ASTM definition of **fatigue** is:

The process of progressive localized permanent structural change occurring in a material subject to conditions which produce fluctuating stresses and strains at some point or points and which may culminate in cracks or complete fracture after a sufficient number of fluctuations.

When a body containing some zone of stress concentration is loaded, stress in a local region may exceed the yield strength, and the material can flow locally, without failure. If this process is reversed, the flow is also

reversed, and if the process is repeated a sufficient number of times, the material may develop a crack due to the damage incurred by plastic strain cycling. The crack then tends to grow or propagate, under the action of the same mechanism that originated it, until the remaining portion of the section is too weak to carry the load and fractures suddenly. This is called a fatigue failure. A familiar example is the failure of a wire coat hanger when it is bent back and forth perhaps a dozen times. The region of stress concentration that initiates the fatigue cracking can be an obvious sharp surface notch or merely a metallurgical defect or discontinuity that is not apparent.

Designers use fatigue design curves, which are plots of allowable alternating stress versus number of cycles anticipated. These design curves are derived from actual fatigue tests that determine the number of cycles to cause failure for various levels of alternating stress. Appropriate safety factors are applied to the results of fatigue tests to establish fatigue design curves. As for creep, a linear damage rule, in this case sometimes called Miner's rule, is often employed, as follows: Suppose a given fatigue loading condition causes an alternating stress that the fatigue design curve shows may be permitted for 100,000 cycles. Suppose further that 5000 cycles of this loading are anticipated. This particular loading is then assumed to cause a cumulative fatigue damage of 5000 cycles divided by 100,000 cycles, or 0.05. Another way of saying this is that 5% of the fatigue life of this component will be expended during this loading. The designer tries to ensure that the cumulative fatigue damage for all anticipated load cycles adds up to less than 100%. Again, difficulties intervene to complicate this seemingly simple approach. At elevated temperature, fatigue life is shortened by the simultaneous accumulation of creep damage. The reduction in cyclic life is also quite dependent on the rate of cycling. A slow fatigue cycle provides more time for creep damage to accumulate. As noted earlier, this is the problem of creep-fatigue interaction.

At first consideration, the loads on a boiler do not seem to be of the type likely to cause fatigue failures, that is, they are not highly repetitive loads. Fatigue failures are often associated with a large number of load cycles — tens of thousands, or hundreds of thousands — although low cycle fatigue failures are not uncommon if the cycle is severe enough. One of the obvious load cycles in a boiler is the start-up and shutdown cycle. During this cycle, the pressure (and, therefore, the pressure stress) varies between zero and some maximum value. More important, and not so obvious, is the thermal stress variation that occurs as the fluid in the boiler heats up and cools down. For instance, suppose the boiler is placed in service quickly, with a fluid temperature increase of 200°F (110°C)/hr. Thick-walled components such as superheater headers develop significant thermal stress due to thermal transients in the fluid passing through them. Since it takes some considerable time for the heat to flow radially through the wall of these components, a considerable radial temperature gradient develops across the wall, as the inner surface follows the fluid temperature but the outer surface lags behind. A 50°F (25°C) temperature difference between the inside and outside of a thick header can cause a thermal compressive stress on the inside surface of perhaps 10,000 psi (70 MPa).

Another severe thermal stress cycle can occur during a so-called hot restart, in which the boiler has been shut down for a short time, but such elements as the superheater outlet header have not cooled significantly and are thus still near their normal 1000°F (540°C) operating temperature. As the boiler is restarted, with minimal firing rate, the initial flow of steam reaching the still hot parts may be much colder than 1000°F (540°C), resulting in a thermal shock and very high thermal tensile stress on inner surfaces. These suddenly cooled inner surfaces would, if free, shrink to a smaller radius, but are constrained by the bulk of the surrounding hot metal. Another example of cyclic loading on a boiler is the thermal expansion and contraction of boiler piping, particularly the main steam piping, during start-up and shutdown.

Until recently, the relatively limited number of cyclic loads on boilers presented few problems for the designer. As more plants are being placed in two-shift operation and as faster starts and shutdowns are desired, fatigue becomes a more important consideration. It is also a key element in life-extension studies. At elevated temperature, fatigue damage is more severe than at room temperature, for a variety of reasons, among them the complex and not yet clearly understood interaction between creep and fatigue. There are as yet very few generally accepted methods to account for all the damage mechanisms involving the interaction of creep and fatigue under realistically varying operating conditions, although many helpful techniques are available, and considerable research effort in this area continues, as discussed next.

BOILER LIFE EXTENSION

The increase in energy costs that began with OPEC's oil embargo in 1973 has had a profound influence on the construction of new steam power and other industrial plants. Fuel costs have gone up sharply and erratically, and it is impossible to predict their future course with any certainty. Because of higher energy costs, users have changed their former wasteful practices, and new equipment is designed to use less energy. Under political pressure to hold down energy costs, public utility commissions have become much less generous than formerly in permitting utilities to recover the cost of new generating plants through rate increases. Whereas in the 1960s, ever larger and more efficient plants were ordered to replace older units and meet steadily increasing electrical demands, growth in electrical usage is now much slower and less predictable than in the past. Furthermore, new units are now no longer likely to be larger or more efficient than most of those presently in service, since practical limits have been reached with respect to size and efficiency and few utilities are interested in pioneering larger units or advanced (higher temperature) cycles. As a matter of prudent business judgment, for most utilities it appears preferable to choose designs that are proven, especially in today's regulatory climate. Moreover, the additional competitive pressures on utilities and economic uncertainties caused by moves toward their deregulation make it more difficult for them to justify investing in new facilities.

As a consequence of all these related factors, owners of power plants, chemical plants, and oil refineries have a strong economic incentive to extend the normal life span of their plants. Accordingly, a great deal of recent research in the United States, Europe, and Japan has been directed at plant life extension and residual-life assessment, which are really opposite sides of the same coin. In the United States much of this research has been under the sponsorship of the Electric Power Research Institute (EPRI), the research arm of the electrical utilities. Studies based on the creep rupture strength of alloy steels typically used in elevated-temperature service show service life of this equipment can be expected to exceed 40 yr, an estimate borne out by experience. This is so even though the allowable stresses at elevated temperatures are based on creep and rupture data extrapolated to 100,000 hr, a time less than 12 yr. As explained in Chapter 15, this is because of the design (safety) factors used on the test data and the fact that the stresses are calculated using design temperature and pressure, both of which are significantly higher than the temperature and pressure at which most equipment actually operates during most of its service life. However, creep rupture life is quite sensitive to temperature, and individual elements such as superheater tubes may suffer creep damage and premature failure if they are subjected to prolonged service at temperatures above their design temperatures. For this reason, in large boilers, it is customary to install thermocouples at selected locations to monitor operating temperatures and provide high-temperature alarms, so that operators can take necessary corrective action.

Current plant life extension efforts typically begin with a thorough investigation of equipment condition to determine suitability for extended service. If the discussion is narrowed to boilers, the components of prime concern are the heavy-walled elements operating at the highest temperatures. As explained earlier, components operating below the creep range may also be a concern, due to wastage and thinning, but assessment of remaining life of such elements is largely one of evaluating wall thickness and corrosion or erosion rates. The material remaining is much less likely to have suffered the gradual deterioration associated with creep and fatigue damage that occurs at higher temperatures. Thus, the prime candidates for investigation are superheater and reheater outlet headers, main steam and hot reheat piping, weld zones, and the tubes that operate at the highest temperatures. Although tubes have relatively thin walls and would thus appear to be less of a concern, experience has shown that they are responsible for most outages. Thus, even though a failed tube can usually be replaced promptly with readily available material, frequent and recurrent tube failures indicate the need for a major tube replacement program, tube redesign, or a change in operating conditions. The principal difference between tubes and heavy-walled components such as headers, so far as thermal stress is concerned, is that the tubes are usually transferring heat, while the headers are not. In the tubes, a large radial temperature gradient causes high steady state thermal stress in the wall, which over time can add to the creep damage caused by pressure stress. On the other hand, thermal stress in walls of heavier components (which are typically outside the hot gas stream and thus not transferring heat) is more likely to be caused by

temperature transients of relatively short duration, such as those occurring during start-up. In such cases, the potential damage mechanism is more likely to be fatigue.

Fatigue damage leading to premature failure is sometimes found in parts of the feedwater piping where intermittent flow causes thermal cycling such as at economizer inlet header nozzles or where flow from the economizer enters the drum. As described above in the section on fatigue, thick-walled components such as superheater headers can develop significant thermal stress and possibly fatigue damage due to thermal transients in the fluid passing through them, which occur during rapid start-up or shutdown of the boiler. For components operating in the creep range (e.g., superheater outlet header, main steam piping) fatigue damage interacts with creep damage, accelerating the process of component life expenditure.

On completion of a screening process to identify components likely to limit extended service life, two general approaches are used for their study and evaluation: **history based methods** and so-called **postservice examinations**. The first of these involves trying to establish the historical record of operating temperature, pressure, and stress to which each component has been subjected. Then by simple stress calculations and conservative (minimum) estimates of material creep rupture strength, an assessment is made of the life fraction that has been expended by using the linear damage rule described above in the discussion of creep. This approach tends to be conservative, but it has some appeal in identifying components likely to require close monitoring during future inspections for signs of damage or incipient failure. Among the drawbacks of history-based methods are uncertainties in the temperature and stress history, scatter in stress rupture data, and questions as to the validity of a simple life fraction rule.

The postservice examination method is an approach in which various techniques are used to assess the remaining life of components at the time the assessment is made, i.e., at the current age of the equipment. Among the techniques used are tests of samples taken from suspect locations and tests of the material in place. For example, accelerated creep rupture tests can be conducted on small boat samples by testing at higher temperature and comparing results with those from similar tests of unused material.

Another method used to assess life fraction expenditure (and thus remaining life) is based on the slow build-up of an oxide layer on the steam side of pressure parts in elevated-temperature service. The growth of this scale has been found to correlate directly with elevated temperature service time and temperature, in a manner analogous to the process of life expenditure associated with creep damage. It is thus possible to find a relationship between time and temperature for scale thickness similar to that discovered by Larson and Miller for creep rupture life under constant stress. In practice, scale thickness is measured microscopically (or in a more recent development, by ultrasonic means). Comparing the measured scale thickness with known data relating scale thickness, time, and temperature, it is possible to estimate an effective service temperature to which the component has been subjected during its service life. Having an effective time, temperature, and stress level, it is then possible from known creep rupture data to assess life expenditure to date and thus remaining life. Fatigue damage must also be accounted for. The process can be refined further by recognizing that an increasing steamside thickness of oxide layer acts as an insulator to raise the effective temperature of the wall. Computer programs have been written to account for this effect as well as for any wall thinning. Both effects accelerate damage, and the programs handle the problem in an iterative manner. Life assessments obtained from oxide film measurements can be supplemented by comparing microstructural changes in the component with standardized samples displaying various degrees of creep damage.

Hardness-based techniques are yet another method for predicting remaining life. These techniques rely on the fact that the strength of low alloy steel changes with elevated-temperature service exposure as a function of time and temperature. Thus, a measured change in strength during service (such as a change in hardness) may be used for estimating the mean temperature at which a component has been operating, and thus how much life expenditure has occurred.

Among the nondestructive methods for making microstructural evaluations is a method of **replication** that reproduces the surface microstructure of a component by means of a cellulose acetate tape applied to its surface. The basic technique consists of surface preparation by grinding, polishing, and etching, using standard metallographic procedures, replication of the prepared surface, and laboratory examination of the replica. To aid in final evaluation, the replica can be enhanced with a vapor-deposited layer of gold or carbon.

Replication permits a survey of an existing component without disturbing it. The technique is relatively inexpensive and can achieve a high degree of resolution to detect creep damage from its earliest stages. A major limitation is its application to accessible surfaces only.

While replication permits determination of form and structure, it does not identify metallurgical components present on the surface. For this, a new technique is under development in which the surface to be examined is etched for a longer time than usual, so that fragments of the material are removed with the replicating tape. These fragments (carbide precipitates) can then be examined microscopically to determine which precipitates are present, in an attempt to identify what stage of creep damage has been reached. This work is still experimental, in part because there is not yet a sufficient database to relate particular metallurgical findings to the various stages of creep damage.

An alternative or adjunct to the replication technique is the use of a microscope for direct examination of the prepared surface on the component. Because of the less-than-ideal conditions in the field (e.g., vibration from nearby machinery), this technique is limited to a magnification on the order of 400 $\times$ and 500 $\times$. From a practical standpoint, this may suffice to identify a problem. If not, the replication techniques permit removal of a surface replica for further study in a laboratory, where greater resolution and magnification are available.

Still another device useful in assessing the condition of boiler components is the borescope. With the aid of a light and optics, a borescope provides a magnified image of otherwise inaccessible interior surfaces. Some advanced borescopes incorporate a miniature camera (a so-called “chip camera”) at the end of a flexible probe that can send an electronic signal to a television screen, providing a large, clear image of whatever the camera sees.

As this brief overview shows, a great deal of recent progress has been made in residual-life assessment. The goals of this effort are several: enhancing safety by providing a sound basis for extending operating life, avoiding or reducing costly unscheduled outages, and eliminating unnecessary or premature equipment replacement. However, the difficulties and uncertainties inherent in the various methods should also be recognized, since they can become cumulative. Some that can be mentioned are: scatter in material property data, lack of sufficient material property data (especially elevated temperature fatigue data), uncertainties in past and future operating conditions (particularly temperature conditions), simplified assumptions utilizing uniaxial creep rupture test data and linear damage rules, and the difficulty of assessing the interaction of creep and fatigue damage under varying temperature and multiaxial stress conditions. Because of these many uncertainties, residual life assessments should always include physical evaluation of microstructural changes, to confirm theoretical predictions, to detect creep damage, and to provide a comparative basis for future inspections.

Much development is still needed in the area of residual-life assessment, which continues to be an active field of research. The Electric Power Research Institute, the research organization for the utilities, has sponsored a great deal of work in this field. Among the tools they have developed with the assistance of other organizations is a computer program called Boiler Life Evaluation and Simulation System (BLESS), which can be used to address various problems in remaining-life evaluation.

DETERMINATION OF ALLOWABLE STRESSES

GENERAL PHILOSOPHY

Each section of the Code uses design criteria and design stresses appropriate for the components that it covers. The basis for establishing allowable stresses is related to the design philosophy, the type of construction permitted, the degree of analysis required, and the amount of nondestructive examination mandated. Sections I, IV, and VIII, Division 1, use a design approach sometimes called design-by-rule. Design-by-rule is not based on detailed stress analysis. Instead, the rules generally involve the calculation of average membrane stress across the thickness of the walls of the vessels. That is not to say that these sections of the Code completely ignore other types of stress. There is a classic statement found in UG-23 of Section VIII, Division 1, which provides a rationale for design-by-rule using membrane stress alone: “It is recognized that high localized discontinuity stresses may exist in vessels designed and fabricated in accordance with these rules. Insofar as practical, design rules for details have been written to limit such stresses to a safe level, consistent with experience.” In the 1970s, the first sentence was slightly different. At that time the term “high localized and secondary bending stresses” was used instead of the current description “high localized discontinuity stresses.” In either case, bending stress and the effects of stress concentrations are not calculated (at least not explicitly) in Section I. This means, in effect, that the Code assigns allowable membrane stresses with sufficient margin (safety factor) to cover high localized stresses in normal circumstances.

The design-by-rule approach has evolved from theory, experiment, and past successful experience. Boilers and pressure vessels thus designed have proven to meet the objectives set forth in the Foreword to all sections of the Code: “to afford reasonably certain protection of life and property and to provide a margin for deterioration in service so as to give a reasonably long safe period of usefulness.” This generally outstanding record of safe and reliable service has been compiled under what can be described as normal conditions. Exceptional conditions, such as severe cyclic loading, high thermal stress, or operation below the temperature of transition between brittle and ductile behavior, have led to failures. Fortunately, with the exception of some heat recovery steam generators (HRSG), boilers are rarely subjected to severe cyclical conditions and, except during hydrostatic testing, are operating at temperatures that preclude brittle fracture. Moreover, designers through long experience have developed means and details to cope with thermal stress.

Design stress for Section I (defined in PG-27 as S , the maximum allowable stress value) is an allowable membrane stress. It is established by using appropriate safety factors against the various potential failure modes of the pressure parts of the boiler. For example, gross yielding of a part is one possible failure mode.

Except as discussed below, Section I uses a factor of safety of 1.5 on this failure mode, i.e., the allowable stress does not exceed $\frac{2}{3}$ of the yield strength of the material. Similarly, a factor of safety (sometimes called a design margin) against bursting is provided by a factor of approximately 3.5 with respect to the ultimate tensile strength of the material. Thus the allowable stress may not exceed about 30% of the tensile strength of the material. Other factors are applied to stress rupture strength and creep rate at high temperatures where time-dependent deformation occurs.

The Section I basis for determination of allowable stress is explained in Section II, Part D, Appendix 1, where the various safety factors, or design factors, and quality factors applied to the various tensile, yield, and creep strengths are presented in Table 1-100. (For ready reference this two-page appendix is reproduced at the end of this chapter.) Appendix 1 also notes that the committee is guided by successful experience in service. Such evidence is considered equivalent to test data where operating conditions are known with reasonable certainty. This philosophy is used to make judgments in establishing stresses for variations of existing material or new materials that are similar to existing materials. Today, requests for the adoption of new materials are typically supported by a great deal of test data, much of it the result of elevated-temperature testing.

ESTABLISHING ALLOWABLE STRESSES

To establish the allowable stresses, certain information over the temperature range of intended use must be known: the tensile strength, the yield strength, the stress that causes a secondary creep rate of 0.01% per 1000 hr, and the stress to cause rupture in 100,000 hr. These data are solicited from all sources available to the BPV Standards Committee on Materials (BPV II). The data are then plotted for the temperature ranges for which the material will be used. There is a standard procedure for normalizing the tensile and yield strength data being studied which involves the ratio of the elevated-temperature strength of the individual lots to their corresponding strength at room temperature. The resulting ratios may then be evaluated by the least-squares procedure to define an average ratio trend curve. Ratio trend curves are then plotted of the tensile strength and yield strength from room temperature to elevated temperature.

The ratio trend curves are then multiplied by the minimum room temperature yield and tensile strength of a particular specification to produce curves of expected strength anchored to those minimum specified strengths. In the high-temperature (creep) region, the creep test data are treated directly, without a normalization technique. A variety of techniques, including time-temperature parametric analysis, is employed to estimate the 100,000 hr stress rupture strength and the 0.01%/1000 hr creep rate. Curves for both the average and minimum stress to produce stress rupture in 100,000 hours are plotted. The tensile strength trend curve is then graphically reduced by a safety factor of about 3.5, and the yield strength trend curve is reduced by a safety factor of 1.5. The average stress to produce a creep rate of 0.01% per 1000 hr is used directly with no factor applied to it. Factors of 67% and 80%, respectively, are applied to the average and minimum stress to cause stress rupture in 100,000 hr. The tensile strength, yield strength, creep rate, and creep rupture strength curves with their respective safety factors applied are then used to generate a single smooth curve representing the lowest values of these curves over the temperature range being considered. That curve is the allowable stress curve.

PENALTIES ON ALLOWABLE STRESSES

There are some materials for which the allowable stresses are made slightly lower than those just described. For example, an additional penalty of 15% applies to longitudinally welded pipe or tube. This is apparently because historically the committee has lacked full confidence in the quality of the weld and the reliability of the NDE methods used to inspect it. Another category, subject to an 8% penalty, is structural quality ferrous material used in pressure-retaining applications. This penalty is an old one, dating from a time when structural

quality may have been a lower quality than so-called pressure vessel quality. It happens that specification SA-6, which provides general requirements for structural materials, calls for somewhat less comprehensive testing than does the comparable specification SA-20, which covers general requirements for steel plates for pressure vessels. However, it could be argued that because the manufacturing processes have improved so much over the years that this penalty may no longer be justified.

By the very nature of their manufacture, steel castings are more likely to have various imperfections than their wrought steel counterparts. PG-25 imposes what it calls a quality factor for steel castings unless all critical areas and weld end preparations pass certain nondestructive examinations outlined in that paragraph. The quality factor is 80%, i.e., a 20% penalty must be applied by the designer to the allowable stress published in Section II, Part D. If the castings pass the required NDE, no penalty need be applied to the allowable stress. Should unacceptable imperfections be discovered, they must be repaired by welding and given a postweld heat treatment. The designer may then use the full allowable stress. However, often a designer may elect to take a 20% penalty on allowable stress and avoid the time, expense, and bother entailed in the fairly extensive NDE required. This can lead to the following situation.

Sometimes a large cast part, such as a pump casing, is welded to boiler piping by a large-diameter circumferential weld. That weld requires radiography, which can reveal unacceptable flaws in the casting adjacent to the weld. Even though the pump designer had decided to accept a 20% stress penalty and forego NDE of the casting, it is generally agreed that an unacceptable flaw must be repaired. Determining which party (e.g., the pump manufacturer, the boiler manufacturer, or the purchaser of the boiler) has responsibility for the costs of the repair would depend on the contracts and specifications that had been agreed to and, perhaps, legal issues such as merchantability, implied warranties, and fitness for service.

From the criteria used to set allowable stresses at elevated temperature, it is seen that Section I permits some high-temperature relaxation or creep. This is based on the philosophy of providing an adequate boiler design life within reasonable economic limits, since experience has shown that some small amount of permanent (creep) strain is not harmful in most circumstances.

Another example of this practical approach occurs in the temperature range in which tensile or yield strength governs the determination of stress (i.e., the temperature range in which creep phenomena do not control the choice of allowable stress). In that range, Section I permits stresses higher than $\frac{2}{3}$ the yield strength for some nonferrous and austenitic materials if some slight permanent deformation (plastic strain) is not objectionable. The use of design stresses relatively closer to the yield strength of these materials can be justified by the fact that these alloys work harden on yielding (they grow stronger) and also that they have a very large margin between yield strength and ultimate tensile strength, i.e., they are very ductile. These alternative higher stresses are identified by a footnote in the Section II, Part D tables. These higher stresses are satisfactory for tubes or pipe, but are not recommended for the design of flanges or other applications where a small amount of creep relaxation or permanent strain might cause leaks or other problems.

DESIGN STRESSES: PAST, PRESENT, AND FUTURE

The so-called safety factors, or design margins, now used in establishing allowable stresses with respect to the various failure modes, such as yielding or creep rupture, have evolved over the life of the Code. Before World War II the factor used on tensile strength was 5. It was changed to 4 in order to save steel during the war. Starting in the late 1970s, the factor on yield strength was changed from $\frac{5}{8}$ to $\frac{2}{3}$, a change that was carried out over quite a long period. The factor on the 100,000-hr creep rupture strength was formerly 0.6. Around 1970, this was changed to the current factor of 0.67. These reductions in design margins, or safety factors, were adopted over time as improvements in technology permitted. These improvements included the development of newer and more reliable methods of analysis, design, and nondestructive examination. The imposition of quality control systems in 1973 and a record of long satisfactory experience also helped justify reducing some of the design conservatism.

One of the design factors the ASME used until 1997 in setting allowable stress not used by most other countries was the factor of approximately 4 on ultimate tensile strength. It happens that this design factor is a significant one because it controls the allowable stress for many ferritic (carbon and low alloy) steels below the creep range. This put users of the ASME Code at a disadvantage in world markets where competing designs are able to utilize higher allowable stresses based just on yield strength. This situation caused the Code committees to reconsider the usefulness and necessity of using tensile strength as one of the criteria for setting allowable stress. In 1996 the Pressure Vessel Research Council (PVRC), a research group closely associated with the Code committees, was asked to study whether the design factor on tensile strength could safely be reduced. The PVRC prepared a report reviewing all the technological improvements in boiler and pressure vessel construction that have occurred since the early 1940s, which was when the design factor on tensile strength was last reduced, from 5 to 4. On the basis of that report's favorable recommendation, BPV VIII decided, as an initial step, to change the factor on tensile strength from about 4 to about 3.5 for pressure vessels constructed under the provisions of Section VIII, Division 1.

BPV I decided to make the same change for Section I and in 1997 established a task group to investigate the potential effects of such a change and how best to implement it. That task group concluded that Section I could safely join Section VIII in increasing its allowable stresses. The actual mechanics of setting and publishing new allowable stresses took BPV II some time because it was quite a task. In order to expedite the process while BPV II completed its work, new stresses for a limited group of materials were introduced by means of Code Cases, one for Section I and two for Section VIII, since Code cases can be issued far more quickly than Code Addenda. The Section I case was Case 2284, Alternative Maximum Allowable Stresses for Section I Construction Based on a Factor of 3.5 on Tensile Strength. The three cases were approved for use in mid-1998, and their higher stress values were incorporated into Section II, Part D in 1999 Addenda.

In the future, it is possible that the design factor on tensile strength may be reduced further or eliminated altogether, depending on the results of these first steps. Note that the change in design factor applied to tensile strength from $1/4$ to $1/3.5$ is a 14% change. However, few allowable stresses will change that much, because the higher allowable stress will probably be determined and controlled by the factor applied to yield strength, rather than tensile strength. Also note that the higher stresses will be applicable below the creep range only.

The above-described methods of setting maximum allowable (design) stress values have been used by the Code committees since the mid-1950s. During that time, new data have been obtained and analyzed to revise design stresses as appropriate, based both on new laboratory tests and reported experience from equipment in service. There have been times when the analysis of new data has resulted in a significant lowering of the allowable stresses at elevated temperature. In all but a few instances, however, the fine safety record of equipment built to the ASME Code has demonstrated the validity of the material data evaluation, design criteria, and design methods used.

APPENDIX 1 OF SECTION II, PART D

Basis for Establishing Stress Values in Tables 1A and 1B (Reproduced From ASME Section II)

1-100 DERIVATION OF ALLOWABLE STRESS VALUES

The values in Tables 1A and 1B are established by the Committee only. In the determination of allowable stress values for materials, the Committee is guided by successful experience in service, insofar as evidence of satisfactory performance is available. Such evidence is considered equivalent to test data where operating conditions are known with reasonable certainty. In the evaluation of new materials, the Committee is guided to a certain extent by the comparison of test information with available data on successful applications of similar materials.

TABLE 1-100
CRITERIA FOR ESTABLISHING ALLOWABLE STRESS VALUES FOR
TABLES 1A AND 1B

PRODUCT/ MATERIAL	ROOM TEMPERATURE AND BELOW		ABOVE ROOM TEMPERATURE					
	TENSILE STRENGTH	YIELD STRENGTH	TENSILE STRENGTH		YIELD STRENGTH		STRESS RUPTURE	
Wrought or cast ferrous and nonferrous	$\frac{S_T}{3.5}$	$\frac{2}{3} S_Y$	$\frac{S_T}{3.5}$	$\frac{1.1}{3.5} S_T R_T$	$\frac{2}{3} S_Y$	$\frac{2}{3} S_Y R_Y$ or $0.9 S_Y R_Y$ [Note (1)]	$F_{avg} S_{R avg}$	$0.8 S_{R min}$
Welded pipe or tube, ferrous and nonferrous	$\frac{0.85}{3.5} S_T$	$\frac{2}{3} \times 0.85 S_Y$	$\frac{0.85}{3.5} S_T$	$\frac{(1.1 \times 0.85)}{3.5} S_T R_T$	$\frac{2}{3} \times 0.85 S_Y$	$\frac{2}{3} \times 0.85 S_Y R_Y$ or $0.9 \times$ $0.85 S_Y R_Y$ [Note (1)]	$(F_{avg} \times 0.85)$ $S_{R avg}$	(0.8×0.85) $S_{R min}$

NOTE:

- (1) Two sets of allowable stress values may be provided in Table 1A for austenitic materials and in Table 1B for specific nonferrous alloys. The lower values are not specifically identified by a footnote. These lower values do not exceed two-thirds of the minimum yield strength at temperature. The higher alternative allowable stresses are identified by a footnote. These higher stresses may exceed two-thirds but do not exceed 90% of the minimum yield strength at temperature. The higher values should be used only where slightly higher deformation is not in itself objectionable. These higher stresses are not recommended for the design of flanges or for other strain sensitive applications.

Nomenclature:

F_{avg} = multiplier applied to average stress for rupture in 100,000 hr. At 1500°F and below, $F_{avg} = 0.67$. Above 1500°F, it is determined from the slope of the log time-to-rupture versus log stress plot at 100,000 hr such that $\log F_{avg} = 1/n$, but it may not exceed 0.67.

R_T = ratio of the average temperature dependent trend curve value of tensile strength to the room temperature tensile strength

R_Y = ratio of the average temperature dependent trend curve value of yield strength to the room temperature yield strength

S_c = average stress to produce a creep rate of 0.01%/1000 hr

$S_{R avg}$ = average stress to cause rupture at the end of 100,000 hr

$S_{R min}$ = minimum stress to cause rupture at the end of 100,000 hr

S_T = specified minimum tensile strength at room temperature, ksi

S_Y = specified minimum yield strength at room temperature, ksi

n = a negative number equal to $\Delta \log$ time-to-rupture divided by $\Delta \log$ stress at 100,000 hr

NA = not applicable

The maximum allowable stress shall be the lowest value obtained from the criteria in Table 1-100. The mechanical properties considered, and the factors applied to establish the maximum allowable stresses, are as given below.

- (a) At temperatures below the range where creep and stress rupture strength govern the selection of stresses, the maximum allowable stress value is the lowest of the following:
- (1) the specified minimum tensile strength at room temperature divided by 3.5
 - (2) the tensile strength at temperature divided by 3.5
 - (3) two-thirds of the specified minimum yield strength at room temperature
 - (4) two-thirds of the yield strength at temperature

In the application of these criteria, the Committee considers the yield strength at temperature to be $S_Y R_Y$, and the tensile strength at temperature to be $1.1 S_T R_T$.

Two sets of allowable stress values are provided in Tables 1A and 1B for austenitic materials and specific nonferrous alloys. The higher alternative allowable stresses are identified by a footnote to the tables. These stresses exceed two-thirds but do not exceed 90% of the minimum yield strength at temperature. The higher stress values should be used only where slightly higher deformation is not in itself objectionable. These higher stresses are not recommended for the design of flanges or other strain sensitive applications.

(b) At temperatures in the range where creep and stress rupture strength govern the selection of stresses, the maximum allowable stress value for all materials is established by the Committee not to exceed the lowest of the following:

- (1) 100% of the average stress to produce a creep rate of 0.01%/1000 hr
- (2) $100F_{avg}$ % of the average stress to cause rupture at the end of 100,000 hr
- (3) 80% of the minimum stress to cause rupture at the end of 100,000 hr

Stress values for high temperatures are based, whenever possible, on representative uniaxial properties of the materials obtained under standard ASTM testing conditions or equivalent. The stress values are based on basic properties of the materials and no consideration is given for corrosive environment, for abnormal temperature and stress conditions, or for other design considerations.

RULES COVERING BOILERS IN SERVICE

INTRODUCTION

As explained in Chapter 9, the signing of the completed Manufacturer's Data Report by the Authorized Inspector and the stamping of the boiler with a Code symbol stamp mark the completion of the boiler. The manufacturer has met its responsibility to supply a boiler which complies with the rules of Section I. Since Section I applies to new construction only, by its own definition in the Foreword, its direct applicability to the boiler has ended. It then becomes the responsibility of the user to maintain the boiler in accordance with requirements of the jurisdiction where the boiler is installed. As can be seen on the map in Chapter 2 showing jurisdictions in the United States and Canada with boiler and pressure vessel laws, all but one state (Wyoming) have boiler laws. For boilers in service, requirements for inspection, maintenance, repair, and alteration vary considerably. Some jurisdictions have specific requirements or invoke those of the National Board Inspection Code (NBIC), which is described below. Unfortunately, however, there are instances each year when lack of proper operating, maintenance, or repair procedures leads to serious accidents. The occurrence of such accidents in the 19th century prompted early legislation to promote boiler safety and eventually culminated in the development of the first edition of Section I in 1915, which comprised what were, in effect, safety rules for the construction of steam boilers.

As early as 1833, Congress passed a law establishing a steamboat inspection service requiring steamboat boilers to be inspected every 6 months. Since those early days of steam, the inspector has played a key role in promoting and assuring boiler safety. Gradually, the various jurisdictions that passed laws regulating boilers established organizations to administer and enforce those laws, which typically cover both new construction and boilers in service.

Recall now the advice in the Foreword to all sections of the ASME Code that its design rules provide a margin for deterioration in service so as to give a reasonably long, safe period of usefulness. Accordingly, it is the general industry practice that the Authorized Inspection Agencies, insurance companies and jurisdictions continue to accept and insure boilers in service where pressure part wall thicknesses have been reduced below their original design values. In such cases, the pressure parts are monitored to establish the rate at which the walls are thinning, and repair or replacement is accomplished before the pressure part deteriorates beyond an acceptable point. It is difficult to find published recommendations regarding what minimum wall thickness is still safe (likely because of the potential liability involved), so the decision on when to replace a deteriorated component is one normally made by the boiler owner in conjunction with his Authorized Inspection Agency or insurer and the jurisdiction.

JURISDICTIONAL REQUIREMENTS

The terms “jurisdiction” and “jurisdictional authorities” are no longer used in Section I. Until the 2004 Addenda, the Foreword cautioned manufacturers and owners to verify acceptance of Code changes by the jurisdiction where the boiler or pressure vessel is to be installed and made reference to “administrative authorities” and “regulatory bodies” elsewhere in the text. While never specifically defining these terms, it was general knowledge that, as used in Section I, such terms meant the state, municipality, or province in which the boiler or pressure vessel was installed. The National Board Inspection Code (NBIC) defines jurisdiction as a “governmental entity with the power, right or authority to interpret and enforce law, rules, or ordinances pertaining to boilers, pressure vessels, or other pressure-retaining items.” The generic definition can be taken to mean any state, province, municipality, or country in the world and is in keeping with the trend towards internationalization of both the ASME Code and the NBIC. With that said, at this writing the term jurisdiction is still generally considered to mean a municipality, state, or province in the United States or Canada.

Jurisdictional requirements covering boilers in service are found in so-called “boiler laws.” In addition to requiring boilers to be constructed to Section I, typical boiler laws mandate periodic inspection of boilers (usually annually) in order to maintain the boiler’s operating certificate. Inspections may be made by an inspector from the jurisdiction or from another organization (typically an Authorized Inspection Agency — AIA) authorized to operate in that jurisdiction. The jurisdiction may have regulations covering the inspector’s duties for boiler inspection. If not, the NBIC (see next section) provides an excellent guide covering general precautions, inspection of pressure parts, piping, and appurtenances such as pressure relief valves, low water fuel cutoffs, pressure gages, etc., and hydrostatic testing if deemed necessary.

Usually, jurisdictional laws also provide rules and regulations regarding repairs and alterations to existing boilers and pressure vessels. These rules, if available, address the codes and standards to be followed, types of processes allowed (e.g., welding, heat treating, NDE, etc.), testing, inspection, recording, and organizations authorized to perform the repairs and alterations. As would be expected, the numerous laws vary from one jurisdiction to the next. Some jurisdictions have adopted the NBIC as governing all repairs and alterations to pressure-retaining items. Others have adopted portions of the NBIC, while still others have modified the NBIC rules and published them in their regulations. Still, with all the variations amongst the jurisdictional rules, it is rare, if ever, that repairs and alterations made in accordance with the NBIC are not recognized and accepted.

NATIONAL BOARD INSPECTION CODE

First published in 1945, the introductory chapter of the National Board Inspection Code (NBIC) provided a brief history of the National Board and its efforts to enforce uniform boiler and pressure vessel laws amongst the various states. It also discussed standardized training and testing of inspectors, the success of the National Board BULLETIN in keeping its members informed of industry best practices, and explained the need for a “consensus” code (i.e., available for review and comment prior to publishing) that would evolve with the industry. By 1947, the NBIC included six chapters covering laws, rules and regulations, inspection of existing and new boilers, boiler repair, and reference data. At this writing, the NBIC is comprised of three volumes, or Parts. Part 1, Installation, identifies minimum safety requirements for installing pressure-retaining items. When adopted by a jurisdiction, this Part becomes mandatory; otherwise, it provides good information and guidance to ensure safe and satisfactory installation of the pressure-retaining items addressed in Part 1. Part 2, Inspection, provides general guidelines and requirements for conducting in-service inspections of pressure-retaining items. It includes precautions for the safety of inspection personnel and references to other codes and standards that provide useful information relative to inspection techniques. Part 3, Repairs and Alterations, provides general requirements that apply when performing repairs and alterations to pressure-retaining items. It also describes the administrative requirements for the accreditation of organizations performing repairs and alterations.

In spite of its long history of striving for uniformity of boiler laws, including those impacting installation, inspection, and repair and alterations, the National Board recognizes that differences remain amongst the various jurisdictions. With this in mind, the National Board Inspection Code cautions installers, inspectors and repair organizations to be familiar with the rules and regulations of the jurisdiction in which the pressure-retaining item is or will be installed. It is wise to heed this advice.

In-Service Inspection of Existing Pressure-Retaining Items

The important role of third party inspection in assuring compliance with the rules of Section I was explained in Chapter 8. Equally important is the inspector's role in maintaining the integrity of the boiler after it is placed in service. As noted above, the National Board, as a leader in this effort, developed and issued the National Board Inspection Code. Containing suggested guidelines, examples of best practices, referenced standards and codes as well as minimum requirements regarding inspection, it is fair to say that the NBIC takes up where Section I leaves off.

Part 2 of the NBIC addresses general as well as specific requirements for in-service inspection of pressure-retaining items. Throughout this and the other Parts of the NBIC, reference is made to the Inspector. As you may recall, Chapter 8 explained that the inspector referred to in Section I is typically an Authorized Inspector (AI), an inspector employed by an ASME accredited Authorized Inspection Agency. In the NBIC, the Inspector is either a National Board Commissioned Inspector or an Owner-User Inspector. It is not uncommon for the new construction inspector (the AI) to also hold a National Board commission to perform in-service inspections of boilers and pressure vessels. But in time, this may change since the National Board rules have changed to allow the commissions to be issued independent of each other. This Inspector is typically permitted to perform new construction and in-service inspections of all boilers and other pressure-retaining items regardless of location or owner. The Owner-User Inspector holds a National Board Owner-User Commission and is an employee of an Owner-User Inspection Organization meeting the National Board rules for such organizations and which is acceptable to the jurisdiction. The Owner-User Inspector is only permitted to perform in-service inspections of boilers and other pressure-retaining items owned or operated (used) by the company that establishes and maintains the Owner-User Inspection Organization. This is very common at large petro-chemical organizations owning or using numerous boilers and pressure vessels. This limitation on the Owner-User Inspector was clarified by Interpretation NBI 98-11.

Question 1: Are inservice inspections performed under the Owner-User accreditation program valid when the inspected items are intended for lease or rent, or installed for use at other locations?

Reply 1: No.

Question 2: Are repair inspections performed by an Owner-User inspection organization valid when the items repaired are intended for lease or rent, or installed for use at another organization's location?

Reply 2: No.

Question 3: May an inspector who is employed by an accredited Owner-User inspection organization perform repair authorization and acceptance inspections for pressure-retaining items not owned or used by the Owner-User accredited inspection organization?

Reply 3: No.

NBIC Part 2, Inspection, begins by providing general rules and guidelines for both the inspector and the owner or user of the item to be inspected. It emphasizes that it's the jurisdictional requirements that determine the pressure-retaining items to be inspected, the frequency and scope of inspections, and the required documentation. Because these requirements vary from one jurisdiction to the next, the Inspector is to have a thorough knowledge of the jurisdictional regulations where the item is installed. It also provides examples of other inspection codes and standards that can provide information and inspection techniques useful to the Inspector. These include, among others:

- National Board Bulletin — Classic Articles Series;
- ASME B31G, Manual for Determining the Remaining Strength of Corroded Pipelines;
- API 579, Fitness For Service; and
- ASME CRTD Volume 41, Risk-Based Inspection for Equipment Life management: An Application Handbook

It goes on to discuss personnel safety, entering confined spaces, equipment operation (not to be done by the Inspector), pre-inspection activities, preparation by the owner-user for internal inspection, and post-inspection activities. It should be noted that guidelines for post-inspection activities do not mention telling the owner or user of the item that repair or replacement of a pressure-retaining item is required. It explains that defects and deficiencies in the condition and the operating and maintenance practices noted during the inspection are to be discussed with the owner user and recommendations made for correction. As explained in the Introduction of this chapter, the decision on when to repair or replace a pressure-retaining item is normally made by the owner-user in conjunction with the inspection agency and insurer. This was clarified by Interpretation NBI 98-05 relating to in-service inspection.

Question: Do the rules of the NBIC require the repair of a pressure-retaining item when the pressure-retaining item no longer complies with the original code of construction?

Reply: No, the NBIC does not provide rules for determining when a repair must be performed.

The remaining sections and supplements of Part 2 of the NBIC describe detailed guidelines and requirements relating to inspection, failure mechanisms, examinations, test methods and evaluations of heating and power boilers, pressure vessels, piping systems, pressure relief devices, locomotive and historical boilers, graphite pressure equipment, fiber-reinforced thermosetting plastic pressure equipment, Yankee dryers, DOT transport tanks, and more. In Section 3 of Part 2, the Inspector is provided information relating to failure mechanisms relating to corrosion such as microscopic corrosion, process variables, material selection, and coatings. It discusses fatigue damage due to cyclic pressure changes and high temperature creep, hydrogen embrittlement and overheating. Section 4, Examinations, Test Methods, and Evaluations, goes well beyond nondestructive examination and pressure testing. It provides valuable descriptions and discussion relating to remaining service life assessment methodology, identification of damage mechanisms, methods of determining inspection intervals for pressure-retaining items subject to erosion and corrosion, items susceptible to brittle fracture, and fatigue. It also provides a description of the basic elements of a risk-based inspection assessment program. It explains that the success of such a program requires the cooperation and commitment of all “team” members consisting of trained and knowledgeable engineers, inspectors, operators and analysts as well as maintenance and management personnel.

As noted at the beginning of this section on in-service inspection, the inspector’s role in maintaining the integrity of the boiler after it is placed in service is equally important to that of assuring compliance with Section I rules during new construction. Part 2 of the NBIC provides a tremendous amount of information and guidance toward that end. Throughout the various sections, the reader is also reminded of what may be the most important aspect of in-service inspection of existing boilers and other pressure-retaining items — the jurisdictional relationships. We are reminded that it is the jurisdictions that mandate rules regarding in-service inspection and these rules vary from one jurisdiction to the next. It is imperative that the Inspector and the owner-user be familiar with and abide by the regulation of the jurisdiction in which the pressure-retaining item is located.

Repairs and Alterations to Existing Pressure-Retaining Items

As noted above, in-service inspection is critical to the safe operation of pressure-retaining items, but inevitably the time comes when the item must be either shut down and decommissioned, or repaired or altered to allow the item to remain in service. NBIC Part 3, Repairs and Alterations, describes the rules and regulations relating to repairs and alterations of existing boilers, pressure vessels and other pressure-retaining items. Like in-service inspection, one should be aware of and be familiar with the variations in jurisdictional rules

regarding repairs and alterations to pressure-retaining items, but for all practical purposes, it is fair to say that NBIC Part 3 is recognized and accepted as the rules governing repairs and alterations. It addresses general and administrative requirements (e.g., inspection, authorization, accreditation, quality system, etc.) as well as rules and guidelines applicable to specific processes (e.g., welding, heat treatment, NDE, bonding, curing, etc.) and pressure-retaining items (e.g., boilers, pressure vessels, graphite pressure equipment, locomotive boilers, Yankee dryers, etc.).

Part 3, Section 1 requires that organizations performing repairs and alterations be accredited as appropriate for the scope of work to be performed. There are three specific accreditation programs.

“R” — Repairs and Alterations to Pressure Retaining Items

“VR” — Repairs to Pressure Relief Valves

“NR” — Repair and Replacement Activities for Nuclear Items

The National Board accreditation process is very similar to that of the ASME. The organization wishing to obtain authorization to use a National Board repair symbol must first submit an application, or request, for the appropriate symbol. A review is then performed to evaluate whether the organization can perform the duties and activities prescribed by the National Board. This review includes a review and evaluation of the applicant’s quality system and its implementation. Based on the results of this review, an organization may be authorized to perform design only, metallic or nonmetallic repairs or alterations, repairs or alterations in the field, in the shop, or both. The authorization may be further defined as applicable to welding, bonding, or mechanical assembly. After obtaining the authorization to use the National Board repair symbol, the organization is generally referred to as the “R” Certificate Holder or repair organization.

Once approved, the “R” Certificate Holder must, of course, adhere to the rules and regulations prescribed in the NBIC Part 3. Before performing a repair or alteration, authorization must be obtained from the Inspector. The Inspector determines whether the repair or alteration methods are acceptable. This includes, among other things, agreeing upon the construction standard to which the work will conform. This is typically the original code of construction. Part 3 explains that when the standard governing the original construction is the ASME Code (or ASME RTP-1), repairs and alterations to pressure-retaining items must conform, insofar as possible, to the section and edition most applicable to the work planned. When the original code of construction is not the ASME code, the work shall conform, insofar as possible, to the edition of the standard or specification most applicable to the work. (As a point of interest, a caveat was added to this requirement permitting use of other codes, standards, or specification when it was not possible or practicable to adhere to the original. This was added to address such equipment as fiber reinforced plastic and graphite vessels because these are typically designed and constructed to proprietary specifications developed by the original equipment manufacturer. As would be expected, the OEM seldom agrees to provide these proprietary specifications for use by organizations other than themselves. In other cases, the OEM may no longer be in business thus making obtaining the specification impossible.) Regarding items constructed to the ASME Code, questions are sometimes asked about the meaning of the term “original code of construction” and of the phrase “the section and edition of the ASME Code most applicable to the work.” This does not mean the Code Edition/Addenda to which the boiler or pressure vessel was originally designed. It may be that Edition/Addenda or any subsequent Edition/Addenda provided it is considered most appropriate to the work planned. This has been clarified by Interpretation NBI 95-19 as follows:

Question: When the NBIC references “the original code of construction,” is it required to use the edition and addenda of that code as used for construction?

Reply: No. The term “original code of construction” refers to the document itself, not the edition/addenda of the document. Repairs and alterations may be performed to the edition/addenda used for the original construction or a later edition/addenda most applicable to the work.

The Inspector and the repair organization must also agree upon whether the planned work is a repair or an alteration. A **repair**, as defined by the NBIC, is the work required to restore the pressure-retaining item to a safe and satisfactory operating condition. This is an important distinction because for many repairs design

calculations are not required. This is particularly true when the original code of construction is known and drawings and documents such as a Manufacturer's Data Report are available. The NBIC does, however, caution the "R" Certificate Holder to assure that all required design information, applicable drawings, specifications, etc., are available and controlled to provide the basis for performing the work, insofar as possible, in accordance with the original code of construction. The NBIC provides a list of examples of repairs to assist the repair organization and the Inspector in determining whether the work is a repair. These examples include replacement of pressure-retaining parts identical to those existing on the pressure-retaining item such as furnace floor tubes, a shell or head, and replacement of nozzles where reinforcement is not a consideration. Other examples include weld buildup of wasted areas, replacement of a pressure-retaining part with a material of different nominal composition, equal to or greater in allowable stress from the original design (provided the material satisfies the requirements of the original code of construction), and replacement of a pressure relieving device provided the relieving capacity is equal to or greater than that required by the original code of construction.

A subclassification of repairs is those designated by the NBIC as **routine repairs**. These are repairs for which in-process involvement of the Inspector and stamping by the "R" Certificate Holder (see the section on documentation and stamping, below) may be waived. These repairs include: welded repairs or replacement of valves, fittings, tubes or pipes NPS 5 (DN 125) and smaller where neither postweld heat treatment nor NDE other than visual are required; addition or repair of nonload bearing attachments; weld buildup of wasted area not greater than 100 in.² (64,520 mm²) or not thicker than 25% of nominal wall thickness or ½ in. (13 mm), whichever is less; and corrosion resistance weld overlay not exceeding 100 in.² (64,520 mm²). This classification of repairs was included in the NBIC to address emergency repairs and those situations where the Inspector could not visit the job site and inspect the work on a timely basis. While such repairs do not require stamping by the repair organization, documentation of the repair, signed by the Inspector, is required. The NBIC cautions the "R" Certificate Holder and the Inspector to determine whether "routine" repairs are acceptable to the jurisdiction. The "R" Certificate Holder's quality system must also describe the process for identifying, controlling and implementing routine repairs.

An **alteration** is defined as a change in the pressure-retaining item described on the original Manufacturer's Data Report which affects the pressure-retaining capability. It also includes nonphysical changes such as an increase in the maximum allowable working pressure, an increase in design temperature, and a reduction in minimum temperature. For alterations, design calculations must be completed before the start of work and be made available for review by the Inspector. The calculations must be completed by an organization experienced in the design portion of the code or standard used for construction of the pressure-retaining item. Some examples of alterations provided by the NBIC include: an increase in the maximum allowable working pressure of a pressure-retaining item; an increase in the heating surface or steaming capacity; a decrease in the minimum temperature; and the addition of new nozzles or openings in a boiler or pressure vessel (except those classified as repairs).

Examination and Testing of Repairs and Alterations

The NBIC requires that the integrity in all repairs and alterations be verified by some form of examination or test. The methods chosen shall provide meaningful results and are subject to acceptance by the Inspector. A test, an examination, or a combination of both may be applied. These include liquid pressure test, pneumatic test, initial service leak test, vacuum test, and a variety of nondestructive examination (NDE) methods and techniques. The tests and NDE methods selected are generally restricted to those recognized by the original code of construction, but when performance of such tests is impracticable and when acceptable to the Inspector, alternative tests or examinations can be used to verify the integrity of the repair or alteration. The use of NDE in lieu of some form of pressure test for alterations is somewhat more restricted than when used for repairs. The NBIC explains that NDE may be used when liquids used for the pressure test may contaminate the pressure-retaining item or when performance of a pressure test is impracticable. Under these circumstances,

concurrence to use NDE in lieu of pressure testing is required of the owner as well as the Inspector and, when required, the jurisdiction.

Certification, Documentation and Stamping

The NBIC Part 3 requires that repairs and alterations be documented, certified and stamped in a fashion that is similar to that of the ASME Code. Repairs performed in accordance with the NBIC are to be documented on Form R-1, Report of Repair. Alterations performed in accordance with the NBIC are to be reported on Form R-2, Report of Alteration.

For repairs, Form R-1 is to be completed by the “R” Certificate Holder performing the repair. The form provides a means of identifying the repair organization that performed the work, the owner and location of the pressure-retaining item, the Edition and Addenda of the NBIC and other codes governing the work, a description of the repair, replacements parts installed, tests applied (e.g., hydrostatic test), and general remarks. The form also provides for the certification by the “R” Certificate Holder that performed the work and the Inspector that performed the inspections of the repair. Copies of the form are to be distributed to the owner or user, the Inspector, the jurisdiction (if required by the jurisdiction) and the agency responsible for the in-service inspection of the pressure-retaining item. When required by the jurisdiction, the Form R-1 is to be registered with the National Board. Repairs performed in accordance with the NBIC shall also be stamped with the “R” symbol by the repair organization performing the work. The stamping may be made directly to the pressure-retaining item or on a nameplate and applied adjacent to the original manufacturer’s stamping or nameplate. Such stamping indicates that the work was performed in accordance with the NBIC and may only be applied with the knowledge and authorization of the Inspector.

The Form R-2 is to be used to document alterations. As noted earlier, calculations for alterations must be performed and made available for review by the Inspector. When physical work to the pressure-retaining item is required for an alteration, the NBIC does not require that the calculations be provided and the physical work performed by the same “R” Certificate Holder. To address this, the Form R-2 provides a means of indentifying the repair organization that provided the calculations as well as the repair organization that performed the construction portion of the work. The Form R-2 is initiated by the “R” Certificate Holder responsible for the design. The design portion of the form is completed and certified by the that certificate holder. The Inspector also indicates review and acceptance of the design by signing the Certificate of Design Change Review. The remainder of the form is very similar to that of the Form R-1. It is completed and distributed by the repair organization performing the construction portion of the alteration. When no construction work is required for the alteration, the “R” Certificate Holder responsible for the design distributes the form. Stamping is also similar to repairs and is to be done by the repair organization doing the construction. When no construction work is required, the “R” Certificate Holder responsible for design applies the stamp. Registration with the National Board of the Form R-2 is required for pressure-retaining items that were originally registered with the National Board.

Referenced Standards and Supplements

In addition to the general requirements for repairs and alterations noted above, the NBIC Part 3 provides special requirements for specific types of pressure-retaining items. These come in the form of Supplements included in NBIC Part 3 and address, among other things:

- Steam Locomotives Firetube Boilers
- Historical Boilers
- Repair and Alteration of Graphite Pressure Equipment
- Repair and Alteration of Fiber-Reinforced Thermosetting Plastic Pressure Equipment
- Repairs and Alterations to Yankee Dryers

- Repair, Alteration and Modification of DOT Transport Tanks
- Repairs to Pressure Relief Devices
- Repair and Alterations of Pressure Vessels in Liquefied Petroleum Gas Service

The NBIC also recognizes that other codes, standards and practices can provide useful guidance regarding repairs and alterations of pressure-retaining items. These include:

- National Board Bulletin — National Board Classic Articles Series
- ASME Post Construction Code
 - ASME PCC-1, Guidelines for Pressure Boundary Bolted Flange Joint Assembly
 - ASME PCC-2, Repair of Pressure Equipment and Piping

The user of these referenced codes and standards is cautioned that some of the referenced methods are considered alterations by the NBIC and in the event of a conflict between the referenced codes and standards and the NBIC, the requirements of the NBIC take precedence.

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APPENDIX I

EVOLUTION OF THE ASME BOILER AND PRESSURE VESSEL CODE

A major goal of this book is to provide an understanding of Section I and its application. That understanding can be enhanced by a review of the history of steam power in the 19th century and the events that led to the development of the first boiler code by the ASME in 1915.

The early 1800s saw the first widespread application of steam in waterborne transport and in factories as an alternative to sail and water power. With steam engines, ships no longer had to depend on the wind, and mills and factories no longer had to be located next to a source of water power. In 1800, typical steam boiler pressure was about 5 psi (35 kPa). This gradually increased to 30 psi (200 kPa) by 1850 and to over 200 psi (1.5 MPa) by 1900. Unfortunately, the development and application of steam power was accompanied by an increasing number of boiler explosions. In the early 19th century, the cause of these explosions was not clearly understood. Reports and articles on boiler explosions included many strange and unproven theories on the cause of the failures. One of these was the formation of hydrogen by the dissolution of water into hydrogen and oxygen, followed by an explosion of the hydrogen. Another was the mistaken belief that water could somehow flash into steam at a pressure higher than the saturation pressure corresponding to the water temperature. In 1830, due to increasing public concern, the Franklin Institute of Philadelphia established a committee to investigate the causes of boiler explosions, to determine the best means of preventing or mitigating them, and of applying and enforcing these remedies. That committee long ago recognized that a code alone was insufficient; it had to be enforceable. The concept of an enforceable code eventually became accepted and is the basis for the successful system we have today.

With funding from the Congress of the United States (the first government support for private research), the committee conducted a large number of experiments on several small boilers, two of which were tested to destruction. One very small boiler [7½ in. (190 mm) in diameter, 14½ inches (368 mm) long] was made entirely of glass and was exposed to the fire over its whole length. This seemingly dangerous device permitted the direct observation of what was happening inside. Another boiler, used for most of these experiments, was a horizontal cylinder of rolled iron, ¼ in. (6 mm) thick, with an inside diameter of 12 in. (300 mm), a length of 2 ft. 10¼ in. (870 mm), and flat riveted heads. Each head had a 2½ in. (63 mm) by 1⅜ inch (35 mm) glass window for observation of the water and steam inside. The setting was of brick. A charcoal-burning grate provided heat to the entire lower surface of the cylinder. There were three try cocks, a glass water gage, a mercury steam gage, a safety valve, thermometers extending to various depths into the shell, a fusible plate, and means to feed water into the steam space and also into the water near the bottom of the shell by using a hand pump.

While these boiler experiments were being conducted, another Franklin Institute committee undertook a comprehensive study of the strength of materials used in the construction of steam boilers. This work took 5 years and culminated in over a 100 tables covering the properties of a variety of materials at different temperatures.

At the conclusion of the investigations, the committee reported that the experiments “have shown not only what are some of the causes of explosions, but, which is quite important, what are certainly not causes”. Five major causes of explosions were then discussed:

1. Excessive pressure that built up gradually
2. Overheated metal
3. Defective construction of the boiler or its appurtenances
4. Carelessness or ignorance of the operators
5. Collapse of boiler or flue due to vacuum within

The committee made a number of recommendations for preventing boiler explosions. Among the recommendations were these: All boilers should be provided with a proper pressure gage; a glass water gage; two adequately sized safety valves, one of which was inaccessible for tampering; and a fusible metal device not in contact with the steam. The committee also stressed the danger from a buildup of boiler scale, the need for frequent internal inspections, and the need for low-water alarms.

The work and conclusions of the Franklin Institute were well received and gave impetus to attempts to legislate rules and regulations for boiler safety. Earlier efforts had been largely unsuccessful, due to lack of general agreement on what should be done and because the proposed legislation was applicable only to cities or states rather than the whole country. In 1833 Congress passed a law establishing a steamboat inspection service. Boilers were required to be inspected every six months, and the inspectors had to certify their soundness. More comprehensive laws were passed in 1838 and 1843, culminating in the Steamboat Act of 1852, which provided the first rules and regulations for the design and construction of boilers. In the latter half of the 19th century, further amendments continued to incorporate improvements in boiler design and safety.

As rules for the design and inspection of boilers evolved, there also developed organizations involved in the inspection and insurance of boilers. As will be seen later, the inspector came to play a key role in the successful functioning of the code. In Europe in the 19th century, similar developments were taking place, with the participation of various governments and marine underwriters.

The rapid growth and industrialization of the United States during the 19th century would not have been possible without the ever widening application of steam power. Unfortunately, there was a darker side to this great progress - a harrowing record of lost lives and damaged property from boiler explosions throughout the United States. One of the worst on record occurred on the steamboat *Sultana* on the Mississippi River on April 27, 1865, 2 weeks after the end of the Civil War. This large ship had been built in 1860 and had a crew of 200. At Vicksburg, it picked up 2000 Federal soldiers who had just been released from prison camps in Alabama and Georgia. Conditions in all prison camps were harsh in those days, but those in the South were notorious. It is thus doubly tragic that most of the 2000 soldiers who had managed to survive the prison camps, and were at last on their way home, were killed when one of the boilers exploded at 3:00 A.M., engulfing the engine room in flames from the wood-fired boilers. The wooden boat burned to the water level in 20 min, with the loss of 1500 lives. Considering the country's population then and now, an equivalent accident today would take almost 7000 lives.

In 1889, the American Boiler Manufacturers Association (ABMA) was formed for the purpose of raising the standards of boiler manufacture and preventing the manufacture and sale of unsafe boilers. The ABMA developed a standard specification for boilers, based on what was considered the best current American and European practice. This specification covered much of the subject matter subsequently included (25 years later) in the first ASME Code. Unfortunately, however, the manufacturers treated the standard specification principally as a device to permit uniformity in bidding, and attempts to promote uniform adoption by the states were thwarted by some members of the Association who could not look beyond the interests of their own companies.

By 1890 typical steam pressure used in prime movers had reached 80 psi (550 kPa). By 1900 pressure in the most advanced designs had reached 250 psi (1.7 MPa). At this time, despite a general understanding of the principle of safe boiler design, laws mandating inspection of steam boilers and licensing of boiler operators, the existence of government and underwriter rules for marine boiler construction and the standard specification for stationary boilers developed by the American Boiler Manufacturers Association, no state

yet had a legal code covering safe stationary boilers. Boiler explosions were occurring at the rate of one a day in the United States.

This situation continued until two major shoe factory boiler explosions occurred in Massachusetts in 1905 and 1906, killing 59 persons and injuring over 100 people. The calamity finally prompted the chief inspector of boilers for Massachusetts to ask for authority to develop a state boiler law governing the construction of most boilers manufactured in or coming into the state. With the support of the governor and the legislature, the first such law was passed in 1907. It was only three pages long, but further rules were added, so that by 1909 the Massachusetts law was fairly comprehensive. It had been formulated by a committee representing a variety of interests: manufacturers, users, inspectors, and a professor from the Massachusetts Institute of Technology.

In 1911, Ohio adopted the Massachusetts rules with a few changes and additions. It had taken 80 years since the Franklin Institute's pioneering and public-spirited investigation of boiler explosions to establish the basis on which the ASME was to develop the ASME Boiler Code over the next 4 years. The Massachusetts and Ohio laws on construction and operation of steam boilers were a major milestone. However, other state and municipal laws dealing primarily with the inspection of boilers differed widely, resulting in a nonuniform, cumbersome system. For example, a boiler built for a given state had to be inspected by an inspector licensed by that state. That same boiler could not be installed in another state that did not recognize the competency of the first state's licensed inspector or that required different construction details. States with no laws became the dumping ground for boilers that could not pass muster elsewhere. What was clearly needed was a uniform set of rules for the construction of steam boilers that could be adopted by all the states as the basis for their boiler laws. What was also needed was a uniform standard of qualification for inspectors that would be accepted by all the states.

The president of the ASME in 1911 was a farsighted individual named Col. E. D. Meier, who was also president of a boiler company and a member of the American Boiler Manufacturer's Association. He had long advocated a uniform set of rules for the construction of steam boilers and believed that a commercially disinterested organization like the ASME, because of its reputation and broad scientific interests, could produce a set of rules that might be adopted by all the states. Col. Meier convinced the Council of the ASME to appoint a committee "to formulate a standard specification for the construction of steam boilers and other pressure vessels and for the care of the same in service." The committee was chosen to represent different interests — consulting engineers, boiler users, boiler manufacturers, steel manufacturers, and the insurance companies.

The committee studied the Massachusetts and Ohio rules and, with few changes, adopted them as the basis of the committee's first draft recommendations. More than 2000 copies of this draft were sent to engineers, engineering educators, engineering societies, boiler manufacturers, material manufacturers, boiler users, and boiler operators all over the world. Recipients were asked for their criticism and suggestions. Many replies were received, and several hearings were held at which all who wished were given an opportunity to speak. As a result of all the comments, many changes were made in the earlier draft, eventually culminating in a final draft that was approved by the Council on March 12, 1915. Although not finally approved and published until 1915, it became what was called the 1914 edition. The title of this final draft was "Rules for the Construction of Stationary Boilers and for Allowable Working Pressures." It was 105 pages long, with a 28-page index. It was made up of Part I for new installations (73 pages on power boilers and 7 pages on heating boilers) and Part II for existing installations (5 pages). An appendix of 20 pages contained methods of computing the efficiency of riveted joints, formulas for braced and stayed surfaces, pressure relief valve capacities, dimensions of standard flanged fittings, and fusible plug requirements. This was the historic first edition of what is now called Rules for Construction of Power Boilers, Section I of the ASME Boiler and Pressure Vessel Code. Many provisions of that first edition remain in Section I today. The Boiler and Pressure Vessel Committee on Power Boilers (BPV I), the committee that administers, interprets and revises Section I, is a standards committee of the ASME Board of Pressure Technology Codes and Standards. It is a direct descendant of the original committee that developed the first edition of Section I.

The authors of this book, past and present, have been privileged to serve on BPV I since the 1970s. Like soldiers who serve in a famous regiment, they feel great pride in this service and do their best to live up to its traditions.

APPENDIX II

ORGANIZATION AND OPERATION OF THE BOILER AND PRESSURE VESSEL STANDARDS COMMITTEES

ORGANIZATION AND RESPONSIBILITY

In 1911, the ASME set up a committee for the purpose of formulating standard rules for the construction of steam boilers and other pressure vessels. The committee is now known as the BPV Standards Committees. From one small group in 1911, the BPV Standards Committees have grown to consist of the Technical Oversight Management Committee (TOMC), the Administrative Committee, the Conference Committee, the Marine Conference Group, the International Interest Review Group, ten standards committees (two nuclear and eight non-nuclear), and numerous subcommittees, subgroups, working groups, and special committees. [Note: In 2009 the BPV Standards Committees underwent a major reorganization. Prior to 2009, the TOMC was called the Standards Committee and was responsible for every action taken by the Boiler and Pressure Vessel Committees. With the growing number of committees and corresponding number and complexity of codes and standards, it became apparent that a single committee — made up of no more than 30 individuals — could not devote the time and resources needed to review, debate and ballot for approval every proposal brought forward by the sub-tier committees. It was recognized that the technical expertise for such action resided in what was, prior to 2009, called Subcommittees (e.g., Subcommittee I, Subcommittee VIII). It was decided that such committees should be responsible for determining the content of the corresponding code or standard and, thus, were re-designated as standards committees (e.g., BPV I, BPV VIII). The TOMC retained, among others things, responsibility for technical oversight by reviewing and commenting on all standards actions (including nuclear), providing advice and recommendations on strategic issues and initiatives, and assuring consistency, where needed, between the various Boiler and Pressure Vessel Codes. Examples include the Foreword and implementation of policies such as that which addresses establishing the governing code edition and addenda.]

At the bottom of the committee structure (where the rubber meets the road, so to speak) are the subgroups and working groups. Typically, these groups are responsible for a specific technical field or a specific part of a section of the Code, for example, the Subgroup on Radiography (a BPV V subgroup) or the Subgroup on Design (a BPV I subgroup). At the standards committee level, the responsibilities broaden to include a complete section of the Code, such as Section I, or a complete technical field, such as Section V, Nondestructive Examination. At the next level is the Technical Oversight Management Committee, consisting of a maximum of 30 members (see above). The TOMC and the standards committees report to the Board on Pressure Technology Codes and Standards (BPTCS). The BPTCS manages the development of codes, standards, guides, and criteria for accreditation and certification programs developed by committees under its jurisdiction, including approval and discharge of personnel of the committees. The boiler and pressure vessel standards committees reporting to the BPTCS are BPV I, II, IV, V,

VIII, IX, X, and XII. As a point of interest, the B31 Code for Pressure Piping Standards Committee also reports to the BPTCS. BPV III and BPV XI report to the Board on Nuclear Codes and Standards.

There are three other committees that act in an advisory capacity to the TOMC. These are called the Conference Committee, the Marine Conference Group, and the International Interest Review Group. These committees represent legal jurisdictions or other authorities who have made the Code a legal requirement, or have accepted the Code as a means of meeting regulatory requirements. Each state in the United States, each province in Canada, and certain large cities that have adopted one or more sections of the ASME Code and maintain a department that enforces the Code are invited to appoint a representative to act on the Conference Committee. There are about 60 such representatives on the committee. An analogous committee is the Marine Conference Group, composed of representatives of marine interests who promulgate and enforce regulations based on the ASME Code. The four members of the Marine Conference Group represent the American Bureau of Shipping, the U.S. Coast Guard, the U.S. Department of the Navy, and Lloyds Register North America. At this writing, nine national representatives from Barbados, Nigeria, Republic of Korea (2), Romania, Singapore, People's Republic of China, Bolivia, and New Zealand have been appointed to the International Interest Review Group.

These committees have direct access to the TOMC and can bring to it any problems with respect to implementation of Code requirements. Members are entitled to participate in discussion and voting at the TOMC and in standards committee ballots for items that are receiving first consideration (explained below under Voting at the Standards Committee). On items receiving reconsideration, these committee members' participation is limited to discussion, without vote. This participation by the regulatory authorities fosters their willingness to accept Code rules in their jurisdictions and assists in uniform administration of the Code.

Many members of ASME may not have a clear picture of its organizational structure and just how and where the BPV Standards Committees fit in. The top ASME level of authority is the Board of Governors. Reporting to the Board of Governors are five Sectors that supervise the next level of the organization consisting of various boards and technical groups. These in turn supervise committees and technical divisions (the BPV Standards Committees are at this level). This general organizational structure is shown in Fig. A.II.1. The particular portion of the structure encompassing the BPV Committee on Power Boilers (BPV I) is shown in Fig. A.II.2. The chain of command leading down to BPV I is as follows: the Board of Governors, the Standards and Certification Sector, the Board on Pressure Technology Codes and Standards, and finally the BPV Committee on Power Boilers (I). BPV I in turn has seven subgroups and a standing task group: Materials, Fabrication and Examination, Piping, Heat Recovery Steam Generators, Design, Locomotive Boilers, General Requirements, and Solar Boilers. Until 1996, there was another subgroup, the Subgroup on Care of Power Boilers, which was traditionally active only for major revisions of Section VII, Recommended Guidelines for the Care of Power Boilers. In 1996, the Subgroup on Care of Power Boilers was disbanded, and its duties were turned over to the Subgroup on General Requirements.

The personnel of these committees are listed in the front of all book sections. Many of the subgroup members are also members of BPV I. The TOMC is made up of a few members from each of the standards committees, usually the chairman, vice chairman, and possibly some subgroup chairmen or other senior members

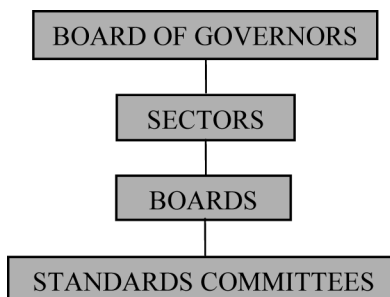


FIG. A.II.1
ORGANIZATION OF ASME (CONDENSED)

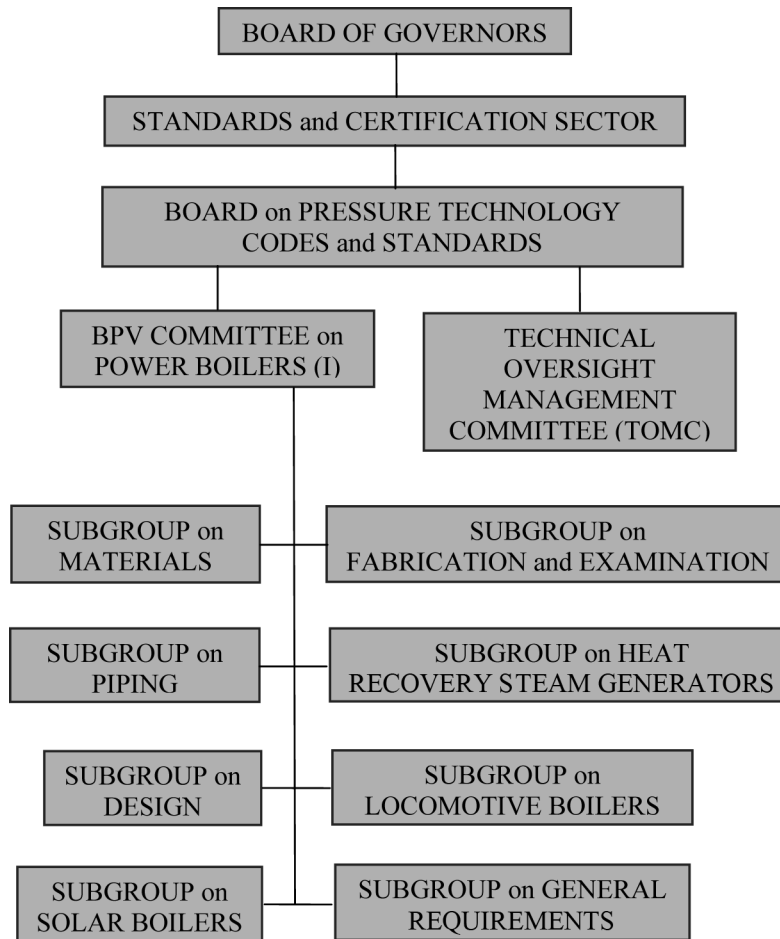


FIG. A.II.2
PORTION OF ASME ORGANIZATION ENCOMPASSING BPV COMMITTEE
ON POWER BOILERS (I)

of the committee. This arrangement of overlapping membership facilitates the work of the TOMC, since certain members of the TOMC are quite familiar with items originating in their respective standards committees and can thus explain and answer questions about the items when they are considered by the TOMC.

A BALANCE OF INTERESTS

Since its inception in 1911 when the Committee was established, it has been ASME policy that the members should represent a balance of interests, to avoid domination by any one interest group. This is one of the ways by which the ASME tries to ensure that actions of the BPV Standards Committees represent a valid technical consensus, fair to all and free of any commercial bias. Above all, the goal of the BPV Standards Committees is to promote the welfare and safety of the public. In furtherance of this goal, each committee member must sign an agreement to adhere to the ASME policy on avoidance of conflict of interest and to conform to the ASME Canon of Ethics. The ASME has also established procedures to provide for due process in BPV Standards Committees operations (e.g., hearings and appeals), thus safeguarding the members and the ASME against any charges of unfairness.

Members of the BPV Standards Committees are categorized according to the interests they represent. ASME has designated 23 categories of interest involved in codes and standards activities. Eight of these categories are represented on BPV I:

1. Designer/Constructor
2. General Interest, such as consulting engineers and educators
3. Insurance/Inspection
4. Manufacturer
5. Manufacturers of material
6. Regulatory, e.g., representatives of local, state, or federal jurisdictions
7. User, i.e., a user of the products to which the Code applies
8. Utility

Individuals typically become members of the BPV Standards Committees by attending committee meetings as guests (meetings are open to the public), by indicating their desire to join, by participating in discussions, and otherwise helping in the work of the committee. There is a practical limit to the size of various committees, and as openings arise, the chair chooses members to maintain a balance of interests on the committees and, occasionally, seeks out individuals with particular expertise. New members usually start by joining a subgroup or working group, and as they gain experience in committee operations and demonstrate their ability by contributing their own expertise, they eventually move up within the committee organization. Prospective members should be aware that they need employer support for committee participation, to cover expenses incidental to meeting attendance and to provide time to carry out committee assignments.

In addition to the many volunteer members of the committee, who are supported in these activities by their companies, the ASME maintains a staff of secretaries who facilitate the work of the committees by taking care of meeting arrangements, preparation of meeting agenda and minutes, arrangements for publication of the Code, scheduling, record keeping, correspondence, and telephone inquiries from the public. Staff secretaries prepare the agenda and take minutes at the TOMC and BPV Standards Committee level. At the subgroup and working group level, one of the volunteer members of the committee usually serves as secretary.

THE CODE SECTIONS AND THEIR RELATED STANDARDS COMMITTEE

The formulation of “standard rules for the construction of steam boilers and other pressure vessels” on which the committee started in 1911 eventually became the first edition of Section I of the ASME Boiler and Pressure Vessel Code, in 1915. That first edition actually dealt only with boilers. Section VIII, covering pressure vessels for other than steam, was added later, in 1925, as part of the expanding coverage of the Code. (Section VIII now covers all kinds of vessels, including those containing steam.) There are now 12 sections of the Code, designated by Roman numerals I through XII. The various sections of the ASME Code (sometimes called the book sections) and the committees directly responsible for each are shown in Table A.II.1.

THE SERVICE COMMITTEE

In addition to the committees governing the various book sections, there is a subcommittee under the Technical Oversight Management Committee commonly referred to as a service committee. It is called a service committee because it serves BPV Standards Committees BPV I, III, IV, VIII, X, and XII.

The Subcommittee on Safety Valve Requirements (SC-SVR) deals with the design, construction, testing, and certification of pressure relief devices. There is no separate book section on safety relief devices; the code sections (I, III, IV, VIII, X, and XII) provide appropriate rules for these devices. Inquiries that pertain to safety relief devices are usually referred by the BPV Standards committees to the Subcommittee on Safety

TABLE A.II.1
THE BOOK SECTIONS OF THE ASME B&PV CODE

CODE SECTION	GOVERNING COMMITTEE
Section I (1915)* Rules for the Construction of Power Boilers	BPV Committee on Power Boilers (I)
Section II (1924) Materials	BPV Committee on Materials (II)
Section III (1963) Nuclear Power Plant Components	BPV Committee on Nuclear Power (III)
Section IV (1923) Heating Boilers	BPV Committee on Heating Boilers (IV)
Section V (1971) Nondestructive Examination	BPV Committee on Nondestructive Examination (V)
Section VI (1971) Recommended Rules for Care and Operation of Heating Boilers	Subgroup on Care and Operation of Heating Boilers (A subgroup of BPV IV)
Section VII (1926) Recommended Guidelines for the Care of Power Boilers	Subgroup on General Requirements (A subgroup of BPV I)
Section VIII (1925) Rules for the Construction of Pressure Vessels	BPV Committee on Pressure Vessels (VIII)
Section IX (1941) Welding and Brazing Qualifications	BPV Committee on Welding (IX)
Section X (1961) Fiberglass-Reinforced Plastic Pressure Vessels	BPV Committee on Reinforced Plastic Pressure Vessels (X)
Section XI (1970) Rules for Inservice Inspection of Nuclear Power Plant Components	BPV Committee on Nuclear Inservice Inspection (XI)
Section XII (2004) Transport Tanks	BPV Committee on Transport Tanks (XII)

*Year shown is first publication as a separate Code Section.

Valve Requirements. Replies approved by that committee are returned to the BPV Standards Committees for further approval and action.

Until 1989, a service committee known as the Subcommittee on Properties of Metals (SC-P) established the allowable stress for all the materials used throughout the Code. In 1989, this committee was merged with the (then) Subcommittee on Material Specifications (SC II) into a new committee called the Subcommittee on Materials (now called BPV Committee on Materials II), which carries out all the duties formerly handled by the two separate committees.

Prior to 2009, another service committee, the Subcommittee on Design (SC-D), reported to the TOMC. That subcommittee dealt with special design problems and helped the other committees in formulating design rules. Among the many subjects covered by that subcommittee were the design of openings, design for external pressure, elevated-temperature design, creep, fatigue, and the interaction of creep and fatigue. The subcommittee was disbanded in 2009 with certain subgroups (e.g., Subgroup on Elevated Temperature Design, Subgroup on Fatigue Strength) being made part of standards committees BPV III and BPV VIII.

THE CERTIFICATION COMMITTEES

As explained in the discussion of the various Code symbol stamps in Chapter 9, no organization may do Code work without first receiving from the ASME a Certificate of Authorization to use one of the Code symbol stamps. The certification committees issue these certificates to applicants found to be qualified by ASME review teams. The Committee on Boiler and Pressure Vessel Conformity Assessment (CBPVCA) handles this work for boiler and pressure vessel activities. The Committee on Nuclear Certification (CNC) does the same for nuclear activities. These committees report to the Board on Conformity Assessment (BCA). Any disagreements as to the qualifications of applicants and any allegations of Code violations are dealt with by one or the other of these two committees, in deliberations that are not open to the general public. An ASME Certificate of Authorization can be revoked for cause, following hearing and appeal procedures.

COMMITTEE OPERATIONS

Since 1986, the BPV Standards Committees have had four major meetings a year, during four weeks known as Code weeks. The Committee used to meet six times a year, but decided to reduce the number of meetings as an economy measure. One of these meetings is known as the “out-of-town” Code week because all the rest used to be held at ASME headquarters in New York City. By 1996, for various reasons (expense and snowstorms being high on the list), only the September meeting was still held in New York City. What used to be the only out-of-town meeting is traditionally held during the first week of May at various locations around the United States and Canada. The out-of-town meeting is held jointly with the annual meeting of the National Board of Boiler and Pressure Vessel Inspectors. The chief inspectors of the various states and provinces who comprise the membership of the National Board are the top officials who enforce those sections of the Code that are adopted into the laws of their jurisdictions. The out-of-town meeting provides an opportunity for them to observe and participate as guests at the various Code committee meetings. The TOMC always meets on Friday; some standards committees (including BPV I) meet on Thursdays, while others, including subgroups and working groups, meet earlier in the week. This arrangement facilitates an orderly and timely flow of information from the lower committees upward to the appropriate standards committee.

HOW THE COMMITTEE DOES ITS WORK

The BPV Standards Committees administer the Code. The major technical work of the Committee falls into three categories: providing interpretations of the Code in response to inquiries, revising the Code, and adding new provisions to it. This work usually starts at the lower levels of the committee structure, the subgroups and working groups. Proposals developed there are then considered at the standards committee level. Many actions of the standards committees (Code changes for instance) require consideration by the TOMC, the Board on Pressure Technology Codes and Standards, the Board on Nuclear Codes and Standards, and, for items relating to conformity assessment, the Board on Conformity Assessment. Technical items are then subject to public review through publication in *Mechanical Engineering* magazine and the *ANSI Reporter*. Thus, these items have received very careful technical consideration within the Committee and are also open to review by the public to avoid any inequity, hardship, or other problem that might result from a Committee action. Any comments received during public review delay an action until the originating committee considers those comments. The several categories of the committee work are described in the following sections.

CODE INQUIRIES AND INTERPRETATIONS

Anyone who has used the Code knows the aptness of the second paragraph of the preamble to Section I: “The Code does not contain rules to cover all details of design and construction.” What it contains, rather, are many

rules for what might be called standard construction at the time the initial Code edition was written. The Code has undergone gradual change since then, as modern steam power plants have evolved, presenting new situations, new arrangements, and new equipment. It is thus not surprising that so many inquiries are received by the BPV Standards Committees, asking for guidance in the application of specific provisions of the Code.

The ASME has established procedures and controls on responding to inquiries and publishes the questions and replies for the guidance of all users of the Code. These procedures are intended to protect the committee members and the ASME from any inference that a specific industry or company has an undue influence in the formulation of the questions or replies, or may benefit to the detriment of others. Sometimes inquirers ask questions that, by policy, a Committee is prohibited from answering. The Committee is not in the business of consulting engineering. It does not have the resources to study plans and details sent in by inquirers and pass judgment on those designs. It also is in no position to undertake the potential liability for making such judgments. Common types of questions considered inappropriate include: indefinite questions that do not address some particular Code requirement; commercial questions; questions that would involve review or approval of a specific design; and questions that ask for the basis or rationale of Code rules. In response to these types of inquiries the Committee advises the inquirer to pose only general questions addressing particular Code requirements, or to make specific recommendations for any proposed Code changes with supporting technical reasons or data.

In 1983, to reduce the work involved in replying to inquiries, mandatory appendices that give instructions on how to prepare technical inquiries were added to the various book sections. (See, for example, Appendix I of Section I). Inquiries are to be sent to the Secretary of the BPV Standards Committee. That secretary assigns the inquiry a unique record number for purposes of tracking the item during its lifetime and sets up a file in an electronic database called C&S Connect. The information included in the file in C&S Connect includes the record number, the responsible committee, name and contact information of the project technical manager assigned to handle the inquiry (initially the subgroup chair), the subject, and any attachments available at the time the file is set up. The chair of the standards committee subgroup responsible for the subject matter is advised of the inquiry with a request that it be considered at the next meeting of the subgroup.

Once the subgroup chair is advised of the inquiry, the chair assigns a project technical manager to handle the inquiry. At times, a task group consisting of three or more members is assigned to assist the project technical manager. Task group members are chosen to maintain a balance of interests. The task group is expected to have a proposed reply ready for presentation at the next meeting, at which time it may be discussed and voted upon. Often there are disagreements about both the question and the proposed reply, particularly if the inquirer has not made her- or himself clear. Revisions to both may be offered, in the interest of clarity, and to make both question and reply as generally applicable as possible. As disposition of the inquiry progresses, the C&S Connect record is updated to include the proposal, an explanation for the proposal, and additional attachments.

The goal of all this work at the subgroup level is to prepare a clear and precise proposal to send on to the standards committee for consideration at its next meeting during the next Code week. A complete information package (the letter of inquiry, any written comments, the proposed reply, pertinent previous replies, etc.) is to be included in the standards committee meeting agenda so that all committee members can study the information before the meeting. However, items that are approved by a subgroup can often be added to the standards committee agenda for the meeting held during the same Code week, especially if the inquirer expresses urgency or if the question and reply appear to be simple and straightforward. This second approach has become common practice for BPV I thus making it possible for BPV I to approve the majority of simple inquiries on their first appearance on the agenda. In a good number of cases, however, the inquiry is not so simple, and a subgroup task group is appointed to try to develop an answer upon which the committee can agree. Inquirers occasionally attend both subgroup and standards committee meetings, and are always welcome to participate in the discussion of their items.

For BPV I, a 75% plurality is required to approve a reply. Negative voters are requested to provide written explanations of their negative votes to guide the subgroup in its next attempt to formulate a reply.

Intent Interpretations

The reader may have noticed in a number of places in this book the phrase “code rules by interpretation.” This phrase is often used by those that believe an interpretation has been issued that does not meet the Code and Standards Policy (CSP-31) prohibiting interpretations that revise existing requirements or establish new requirements. In the early days of issuing Code interpretations this appeared to be a fairly common practice of the various Standards Committees. To provide a means of responding to inquiries while not violating CSP-31, the policy was revised to include what is called “intent” interpretations. Inquiries that cannot be answered on the basis of existing wording of the Code may, within certain parameters, be answered by an intent interpretation. An intent interpretation is permitted only to clarify conflicting or ambiguous wording or to resolve incorrect wording. The intent interpretation must be accompanied by proposed revisions to the Code that support the interpretation. For BPV I, intent interpretations and the supporting Code revisions are subject to the same voting criteria as Code Cases and Code revisions. (See Voting at the Standards Committee, below.) The following interpretation, I-01-39 is an example of an intent interpretation.

Question (I): *Is it the intent of PG-99.4.1 that the required hydrostatic test pressure be achieved at the highest point in the boiler?*

Reply (I): *Yes; however, measurement may be performed at other elevations, provided the required pressure is adjusted to include the hydrostatic head.*

Question (2): *Does the 6% overpressure criterion of PG-99.1 apply at the highest point in the boiler?*

Reply (2): *Yes.*

Proposed revisions to PG-99 accompanied the interpretation and, in the 2003 Addenda, PG-99 was revised to read (in part) as follows.

PG-99 Hydrostatic Test

Hydrostatic testing of the completed boiler unit shall be conducted in accordance with the following requirements:

After a boiler has been completed (see PG-104), it shall be subjected to pressure tests using water at not less than ambient temperature, but in no case less than 70°F (20°C). ***Where required test pressures are specified in this paragraph, whether minimum or maximum pressures, they apply to the highest point of the boiler system.*** (Bold Italics added by authors.)

PG-99.4.1 An indicating gage, visible to the operator controlling the pressure applied, shall be connected to the pressure parts. ***Hydrostatic head on the gage shall be considered such that the required test pressure is achieved at the top of the boiler.*** (Bold Italics added by authors.)

PUBLICATION OF INTERPRETATIONS OF THE CODE

Before 1977, there was no formal mechanism for the publication and dissemination of replies by the ASME BPV Standards Committees to inquiries on the interpretation of the Code. Starting in January 1977 and continuing until June 1982, the ASME twice a year published a paperback volume containing all the written replies by the ASME staff on behalf of the Committee to inquiries on the interpretation of the Code. For the convenience of the reader, these were presented chronologically in separate groups identified by the Code Sections to which they apply.

To receive the paperback volumes of Code Interpretations, it was necessary, at that time, to subscribe and pay a fee. Most purchasers of the various Code books did not subscribe, defeating the major goal of their publication, namely, making this information widely available to users of the Code. Thus, starting with June 1982, the ASME began issuing the interpretations twice a year in loose-leaf form to all purchasers of Code books. (Each section is issued only interpretations pertaining to that section.) A very useful feature of this service is a cumulative index by paragraph number and also by subject, although the subject may not ac-

curately describe the essence of the interpretation. The Foreword to the interpretations contains a disclaimer to the effect that the interpretations are not a part of the Addenda or the Code. In 1995, a committee member raised concerns as to the official status of interpretations. This prompted a reconsideration of this disclaimer. It was explained by the ASME staff that the disclaimer was originally intended to mean only that buying the Code books did not entitle a purchaser to receive the interpretations without paying extra. In 1996, the Main Committee (now the TOMC) approved the following interpretation, identified as item number BC96-134 and issued as Section VIII Interpretation VIII-1-95-159:

Question: The cover page of Interpretations Volumes and page iii in each Section of the Code state, "Interpretations are not part of the Code or the Addenda." Do interpretations establish new Code rules?

Reply: No. The quoted statement refers to the publication and distribution service for interpretations.

Interpretations explain or clarify rules in specific Editions or Addenda of the Code.

The essence of this interpretation has been incorporated into the mandatory appendices regarding submittal of technical inquiries. Paragraph I-1.a.3 of Section I Mandatory Appendix I states that Code interpretations provide clarification of the meaning of existing rules and do not introduce new requirements. Thus, although the interpretations may not literally be a part of the Code, they serve a number of useful purposes. The published replies often contain detailed guidance and explanation about some specific topic for which Section I (or another section) provides only general rules. As explained earlier, Section I is neither a textbook nor a design manual; it is a system of rules with very limited explanation of intent. Thus it is particularly helpful to have what is, in effect, a current consensus of BPV I on the meaning or interpretation of some Section I rules, or on how to treat some situation not explicitly covered by Section I. The interpretations also provide a good indication of what the reply to a similar question might be. Authorized Inspectors are often guided by interpretations in deciding whether to accept a particular form of construction, therefore the replies are likely to be of interest and benefit to many others besides the inquirer.

One caveat: An interpretation applies either to the Edition and Addenda in effect on the date of issuance of the interpretation or the Edition and Addenda stated in the interpretation. Subsequent revisions to the Code may supersede the interpretation.

ADDITIONS AND REVISIONS TO THE CODE

The Code is subject to continuous change — some provisions are revised, others deleted, still others added. Although some changes originate high in the committee structure (e.g., the mandatory appendices in each book section on preparation of technical inquiries), most start at the subgroup level in response to an inquirer's request for a change, or a request by members of the committee to clarify, update, or expand existing Code provisions.

The development of a Code change follows a path similar to that of a technical inquiry. The cognizant subgroup chair assigns a task group to do the work. Often, more than one subgroup may be involved and the task group may include members from more than one subgroup. In appointing the task group, the chair tries to maintain a balance of interests while making sure to include members with the specific expertise appropriate for the task. If and when the subgroup approves the change proposed by the task group, the proposal is forwarded to BPV I for consideration, with documentation giving the background of the proposed change.

During deliberation on the item by BPV I, the item may be approved, or further changes may be suggested, or strenuous objections may be raised, in which case the chair may accept the presentation as a so-called "progress report" and return the item to the subgroup for further work. The subgroup then attempts to modify the proposal to overcome the objection raised at the standards committee level. Usually, this process of refinement leads to a proposal that is eventually approved by BPV I. Voting on this type of action is explained later in this appendix, under Voting at The Standards Committee.

CODE CASES

One of the many definitions of the word case is “a special situation,” which is a good description of the circumstances covered by what the BPV Standards Committees calls a Case. In the early application of the first edition of the Code, users sought the BPV Standards Committees’ guidance for circumstances not specifically covered by the Code and when the intent of the Code rules was not clear. The Committees considered a number of these special situations and issued formal guidance in the form of what it called a Case. This is the origin of the practice of issuing numbered Code Cases. In those days, no distinction was yet made between a Case and what we now call an interpretation.

Today, Code Cases are used for several purposes:

1. To provide for early implementation of new or revised Code rules, since a Code Case can be approved and published more quickly than the text of the Code can be revised. A text change can take well over a year after approval before it is published, while a Code Case is acceptable for use immediately upon approval.
2. To permit the use of new materials or new forms of construction not covered or not otherwise permitted by existing Code rules, when the need is urgent.
3. To gain experience over a period of time with new materials, new forms of construction, or new design rules before changing the Code to include them. This is particularly useful for rapidly evolving technology.

Code Cases may be annulled at any time by the BPV Standards Committees, but usually Code Cases are annulled 6 months after their contents have been incorporated and published in Addenda to the Code.

Some other special aspects of Code Cases are these:

- Code Cases are nonmandatory; they are permissive only. In effect, they are an extension of the Code.
- If a Code Case permits some deviation from normal Code rules, it usually stipulates some compensating extra requirements. An example of such a case was the provision (now included in Section I, PW-54.3) permitting some nonpressure parts to be welded to pressure parts after the hydrostatic test if five conditions were met for welding, inspection, and documentation. Usually, when a Code Case is used, the Code Case number must be listed on the Data Report.
- All Code Cases must clearly indicate their limits of applicability.
- Code Cases have an inquiry and reply format. The inquiry describes the circumstances and asks for guidance. The reply always starts with the words “It is the opinion of the Committee that . . .” This opinion phraseology is used because presumably there are no explicit rules in the Code covering the particular circumstances, and thus the BPV Standards Committee can only give its opinion.
- Code Cases may not contain references to other Code Cases, since Code Case life is usually short and the reference might soon be annulled.
- Although there used to be pressure to incorporate all Code Cases into the Code as soon as adequate experience had been gained with their use, it is now recognized that some cases do not lend themselves to incorporation and will be left as Code Cases indefinitely. An example is Case 1918, Attachment of Nozzles or Couplings to a Boiler Vessel after Postweld Heat Treatment. The BPV Standards Committees have refused to incorporate this case because of concerns that it could be routinely used to avoid postweld heat treatment of nozzles on boiler vessels.

Code Cases are approved in the same way as revisions to the Code. Often some urgency is involved, and the interested parties do much of the work, such as preparing the initial draft of the case. Sometimes more than one standards committee is involved. Many cases involve use of new materials, or use of materials at higher temperatures than before. In such instances, the BPV Committee on Materials (II) establishes the allowable stresses to be listed in the case.

The ASME publishes Code Cases in two Code Case books: Boilers and Pressure Vessels, and Nuclear Components. Supplements with the latest cases and annulments are now sent quarterly to purchasers of the Code Case books. Issuing the new cases quarterly theoretically enables the publication of new Code Cases as soon after approval as possible. However, an interested inquirer can contact the Secretary of the BPV Standards Committees and find out whether a particular Code Case has been approved for use. If the case has been approved, it may be used immediately.

VOTING AT THE STANDARDS COMMITTEE (BPV I)

Items coming before BPV I are considered within two voting categories: first consideration vote and recirculation vote, usually called second consideration. A new item appearing for the first time is given “first consideration” by BPV I. On first consideration, the item is concurrently reviewed by BPV I, the TOMC, the Conference Committee, the Marine Conference Group, the International Interest Review Group, and the Board (BPTCS). A single negative vote from any of these is sufficient to stop the item and return it to the originating subgroup for reconsideration. A negative vote must be supported by a written explanation of the reasons for the negative vote.

The negative ballots and explanations are provided, via the C&S Connect balloting database, to the subgroups from which the item came, where the objections of the negative voters can be considered. It is there that a response to a negative ballot is developed. Sometimes the objector offers some constructive suggestions that will satisfy his or her concerns, and if these are acceptable to the subgroup originating the item, the changes are made, approved by the subgroup, and the item is returned to BPV I. At other times, the subgroup may consider the objections invalid and refuse to make any change. In that case, the subgroup votes to reaffirm the item and returns the item to BPV I with an accompanying rebuttal to the objections of the negative voter.

When the item is returned to BPV I, its status may be either first or second consideration, depending on whether its technical substance has been changed significantly or whether the change has been merely editorial. If the item is returned with some technical change, its status remains as first consideration (in the changed form). It is then subject to another vote in which one negative ballot can again return it for reconsideration. If the item is returned to BPV I technically unchanged, its status becomes “second consideration.” During second consideration, only BPV I members vote and three BPV I negative ballots are required to stop and, in effect, kill the item. If the originating subgroup wants to pursue the matter further, it must start all over, usually by making sufficient revision to satisfy the objections raised. The new appearance of the item would be a new first consideration. On the other hand, if on second consideration an item receives less than three negative votes, it is considered approved by BPV I and it proceeds to the next two approval levels, Board review and public review. If there are no unresolved substantive Board comments or public review comments, the action is administratively approved and proceeds for publication.

Most of the items considered by a standards committee such as BPV I are proposed changes in the corresponding book section of the Code. Fairly regularly, some items fail to pass first consideration because of strong objections by TOMC or other conference committee members who perceive the change as having negative consequences to safety or representing an unworkable situation when applied to other comparable circumstances. This is part of the give-and-take of committee actions, which are intended to achieve a technical consensus of the membership, but with concern for safety always being paramount.

DUE PROCESS

Persons who consider themselves injured by an action of the Committee regarding a technical revision, response to an inquiry, or the refusal to issue a certificate of authorization, can request a hearing to present their side of the story. Such hearings start at the standards committee that originated the item. Appeals that cannot be resolved at the standards committee level may be referred to the supervisory board. (For BPV I, that would

be the BPTCS.) If the board cannot reach a mutually acceptable solution, the appeal may be submitted to the Codes and Standards Board of Directors' Board on Hearings and Appeals. This careful attention to due process is the result of an unfortunate event that happened in 1971. Here is the essence of that case.

Section IV stipulates that boilers must have an automatic low-water fuel cutoff that stops the fuel supply when the surface of the water falls to the lowest visible part of the water gage glass. A company had developed a new probe-type low-water fuel cutoff that relied on an electrode on the probe. Water covering the electrode completed a circuit that maintained fuel flow. When the water level fell below the electrode and uncovered it, the circuit was broken and the fuel was stopped.

At that time, another manufacturer dominated the low-water fuel cutoff market with a float-operated device. That rival manufacturer happened to have a representative serving as vice-chair of the Section IV committee. Court records subsequently showed that three officers of the rival manufacturer, including that vice-chair, met with the chair of the committee to draft an inquiry to the committee. The inquiry asked whether a low-water cutoff with a time-delay feature met the Code. The committee chair at that time had the authority to respond to the inquiry on behalf of the ASME without the endorsement of the full committee. His letter of response implied that the device did not meet Section IV requirements and would not provide adequate safety. The company subsequently alleged that the inquiry was deliberately intended to put the probe-type device in a bad light and that copies of the ASME response were used by the rival manufacturer's sales force to discredit the device. When a former customer reported this to the company in 1972, the company complained to the ASME and asked for a clarification of the ruling. This time the ruling was put before the entire Section IV committee (the vice-president of the rival manufacturer had by this time become chair of the committee) where it was reconfirmed, perhaps because of the subcommittee's belief that the Code required the fuel to be cut off as soon as the water level was no longer visible in the water gage glass (and not after a time delay). However, the Main Committee (now the TOMC) reversed the ruling and issued an official communication to the company saying that the Section IV paragraph in question did not prohibit the use of a low-water cutoff with a time delay.

In 1975 the company sued the parties, including the ASME, alleging conspiracy in restraint of trade. The other parties settled, but the ASME contested the charge, in the understandable belief that it had done no wrong. A district court judge awarded the company \$7.5 million in damages. The ASME appealed, lost that appeal, and then appealed to the U.S. Supreme Court, which affirmed the appellate court's decision. The essence of the court's finding was that the ASME had put certain committee members in positions where they appeared to represent the ASME and had thereby conferred on those agents the ASME's so-called apparent authority. Even though the ASME is a nonprofit professional organization, it was found liable for the willful, anticompetitive, wrongful conduct of its agents. With interest on the triple damages called for by the antitrust act, ASME had to pay almost 10 million dollars (in addition, of course, to legal fees). This was a heavy price for an educational nonprofit organization that gets much of its financial support from the dues of its members. Following that decision, the ASME developed improved procedures in an attempt to ensure the fairness of interpretations and to provide for hearings and appeals for anyone who considers himself injured by an action of the Code committee, such as an interpretation or a proposed Code change. These procedures should prevent any further cases like the one just described.

APPENDIX III

OVERVIEW OF CODE SECTIONS II TO XII AND PIPING CODES B31.1 AND B31.3

Users of Section I soon find that they need to know something about the other Code sections and piping codes involved in boiler and pressure vessel construction. Although some of these codes are described in detail elsewhere in the text, a brief overview of all of them is provided here, for ready reference.

When Section I was first published, in 1915, it was the entire ASME boiler code, and all the boiler construction rules were contained in a single volume. That volume eventually expanded to the extent that it became logical and convenient to establish separate sections covering components other than boilers and various aspects of Code construction, such as welding and nondestructive examination. Consequently, we now have the following sections, first published in the years indicated:

Section I	Rules for Construction of Power Boilers (1915)
Section II	Materials (1924)
Section III	Rules for Construction of Nuclear Facility Components (1963). (The designation Section III had earlier been used for locomotive boilers.)
Section IV	Rules for Construction of Heating Boilers (1923)
Section V	Nondestructive Examination (1971)
Section VI	Recommended Rules for Care and Operation of Heating Boilers (1971)
Section VII	Recommended Guidelines for the Care of Power Boilers (1926)
Section VIII	Rules for Construction of Pressure Vessels (1925)
Section IX	Welding and Brazing Qualifications (1941)
Section X	Fiber-Reinforced Plastic Pressure Vessels (1961)
Section XI	Rules for Inservice Inspection of Nuclear Power Plant Components (1970)
Section XII	Rules for Construction and Continued Service of Transport Tanks (2004)

There are two piping codes most commonly used to design the piping associated with boilers and pressure vessels. These are ASME B31.1, Power Piping, and ASME B31.3, Process Piping, which until 1996 was known as Chemical Plant and Petroleum Refinery Piping.

Section I has been covered in detail in this book. Here is a brief overview of the other book sections and of the two piping Codes, starting with Section II, Materials.

Section II, Materials

This is a four-part compendium of materials data, almost a foot thick in its entirety. The four volumes of Section II are as follows:

- Part A — Ferrous Material Specifications
- Part B — Nonferrous Material Specifications

Part C — Specification for Welding Rods, Electrodes, and Filler Metals

Part D — Properties

Parts A, B, and C are, as their names indicate, a compendium of ASME material specifications for all the pressure vessel and welding materials permitted for use in Code construction by Sections I, III, IV, VIII, and XII. These specifications are first adopted by ASTM (the American Society for Testing Materials) and are subsequently adopted, sometimes with minor modification, by ASME. It is important to remember that not every material listed in Section II can be used in Section I (boiler) construction. (This is explained in Chapter 3.) In general, only materials listed in the material paragraphs of Section I — PG-5 through PG-13 — may be used for Section I pressure-retaining parts. PG-11 also permits use of most materials listed in the ANSI standards recognized by Section I in PG-42.

The last part of Section II, Part D, was first issued in 1992. It lists material properties for all materials accepted by the book sections I, III, VIII and XII. Most important, it lists allowable stresses as a function of temperature. Until 1992, these stresses had been listed separately in those individual book sections. The ostensible purpose of Part D was to consolidate all this information in a single volume, organized into subparts covering stress tables, physical property tables, and external pressure charts. Also included are several appendices. One describes the basis for establishing the allowable stress and design stress intensity values (the latter are used in the design of so-called Class 1 nuclear power plant components and Section VIII, Division 2 vessels). Another describes how charts for external pressure design are established and what criteria are used to determine allowable compressive stresses when designing for external pressure. Unfortunately, Part D lacks a useful index, and although efforts are underway to make it easier to use, finding any needed information in the various tables, such as a particular material and grade, is difficult. (A brief description of how the various materials are sorted and listed is provided in Chapter 3: Materials.)

One useful feature of Section II, Part D is its physical property tables, which provide such information as coefficients of thermal expansion, thermal conductivity, thermal diffusivity, moduli of elasticity, Poisson's ratio, modulus of rigidity, density, melting point range, and specific heat for a fairly large variety of materials. Much of this information is provided over a large temperature range. Also included are tables of yield and ultimate tensile strength as a function of temperature, up to 1000°F (540°C).

For various historic and technical reasons, the several Code book sections that deal with the design of metal pressure vessels (Section I, III, IV, VIII, and XII) do not all use the same allowable stresses. Section I, Section VIII, Division 1, and B31.1, Power Piping, establish allowable stresses based on the same criteria. Section IV uses allowable stresses that are (for most components) lower than those permitted by Sections I and VIII, Division 1. Section III has many different classes of construction, and the allowable stress basis varies. For Class 1 components, which are designed using a method called design-by-analysis (see below, under Section III), allowable stresses are somewhat higher than those permitted by Section I and Section VIII, Division 1. These same higher stresses are permitted by Section VIII, Division 2, which also requires design-by-analysis. The higher stresses come at the price of enhanced care in manufacture. All these different allowable stress criteria require many different stress tables in Section II, Part D. See Chapter 15 and the next topic in this appendix for further discussion of allowable stress.

Section III, Rules for Construction of Nuclear Facility Components

This section of the Code was first published in 1963, as a single slender volume. It was based in large part on a 1958 U.S. Navy document entitled *Tentative Structural Design Basis for Reactor Pressure Vessels and Directly Associated Components* by three distinguished pioneers in the development of nuclear power: Bernard F. Langer, then with Westinghouse Bettis Laboratories; James Mershon, then with the U.S. Navy Bureau of Ships; and W.E. Cooper, then with GE's Knolls Atomic Power Laboratory.

This seminal document first set out in systematic fashion the methods and principles of what has come to be known as the concept of design-by-analysis, because of the important role stress analysis plays in this

design process. This concept, based on fundamental considerations of analysis and material behavior, was a truly great step in the evolution of pressure vessel design. It is now the basis for the structural evaluation requirements of Section III and Section VIII, Division 2, and has been widely adopted in other countries. Design-by-analysis is a unified concept of design that accounts for most possible failure modes and provides rational margins of safety against each type of failure.

This concept permits the use of higher allowable stresses with no reduction in safety by requiring a rigorous analysis and classification of all types of stresses and loading conditions in addition to better control of manufacturing and inspection procedures. The sections of the Code that use design-by-analysis require a detailed design specification, defining among other things all anticipated loading conditions, and a complete design report; both items must be certified by registered Professional Engineers experienced in pressure vessel design.

Section III expanded greatly during the heyday of nuclear power. It now comprises ten volumes in two divisions, one for steel structures and the other for concrete reactor vessels and containments.

Most of the design rules and allowable stresses of Section III extend only to temperatures at which creep effects are insignificant [$\sim 800^{\circ}\text{F}$ (425°C)], i.e., these stresses are based on time-independent tensile or yield strength properties. Thus, these rules do not extend to elevated-temperature service. However, such service was covered by a famous nuclear Code Case, Case N47, Class I Components in Elevated Temperature Service, a major design document of well over 100 pages. After about 30 yr of development and use, that Code Case was incorporated into Section III as Subsection NH, with the 1995 Addenda. Subsection NH provides complex rules for overcoming the difficulty of designing in the creep range. The difficulty arises from the inherent complexity of the creep process, which cannot be characterized precisely, particularly under varying temperatures and multi-axial states of stress. Creep behavior complicates the detailed stress analysis because the distribution of stress varies with time as well as with the applied loads. Even with the NH rules, elevated-temperature design is difficult at best. See Chapter 14 for a further discussion of these difficulties.

Section IV, Rules for Construction of Heating Boilers

This section of the Code provides rules for the design, construction, installation, instrumentation, and certification of a somewhat diverse group of relatively low-pressure steam boilers and water heaters. The preamble to Section IV describes these as steam heating boilers, hot water heating boilers, hot water supply boilers, and potable water heaters.

The design pressures of these boilers vary from 30 psi (200 kPa) to 160 psi (1.1 MPa) and design temperatures do not exceed 250°F (120°C). (Above these limits a boiler would, by definition, be a power boiler, falling within the scope of Section I.) Section IV steam boilers have an **operating** limit of 15 psi (100 kPa), so the safety valves must be set at 15 psi (100 kPa). Potable water heaters are designed for pressures up to 160 psi (1.1 MPa) [with a minimum of 100 psi (700 kPa)] and for temperatures not to exceed 210°F (100°C). The purpose of the 210°F (100°C) limit is to prevent any water discharged from relief valves or other connections from flashing to steam.

Aside from the lower pressures and additional coverage of installation and instrumentation, the most significant difference between Sections I and IV is that Section IV does not require any nondestructive examination. Accordingly, Section IV, in general, has a lower allowable stress (a margin of 5:1 versus 3.5:1 based on ultimate tensile strength).

Section V, Nondestructive Examination

This Code book starts with Article 1 on General Requirements. The first paragraph (T-110 Scope) of Article 1 gives a good description of what it covers:

T-110 Scope

This Section of the Code contains requirements and methods for nondestructive examination (NDE), which are Code requirements to the extent they are specifically referenced and required by other Code Sections or referencing document. These NDE methods are intended to detect surface and internal imperfections in materials, welds, fabricated parts, and components. They include radiographic examination, ultrasonic examination, liquid penetrant examination, magnetic particle examination, eddy current examination, visual examination, leak testing, and acoustic emission examination.

Article 1 goes on to discuss the manufacturer's responsibility to establish suitable examination procedures and to have the examination performed by qualified personnel. The duties of the Authorized Inspector are then explained. Further advice is given regarding examination procedures and the qualification of personnel who carry them out. The rest of Section V comprises Subsection A (17 articles describing in great detail nondestructive methods of examination), Subsection B (8 articles consisting of standards for different types of nondestructive testing, e.g., SE-94 Standard Guide for Radiographic Testing), and mandatory and non-mandatory appendices.

One point to remember is that the NDE methods of Section V are mandatory only when and to the extent they are invoked in one of the other book sections. Also, the acceptance standards are provided in the referencing book section. Note also that Section I calls for only some of the many NDE methods listed in Section V. These are radiographic, ultrasonic, magnetic particle, dye penetrant, and visual examinations. Section I makes no mention of acoustic emission examination of metallic vessels during pressure testing. Acoustic emission testing is relatively new, and its application to Section I construction does not appear needed or potentially useful. It is sometimes applied for nuclear in-service inspection and for fiber reinforced plastic pressure vessels, where it can presumably detect crack growth.

Section VI, Recommended Rules for the Care and Operation of Heating Boilers

Notice first that this Code section is nonmandatory, i.e., these are only recommended rules for the care and operation of heating boilers. Nevertheless, the rules represent a consensus on what is considered good practice. The rules of Section VI apply only to Section IV boilers and provides a great deal of detailed information and advice on various boiler types and their accessories such as safety valves, circulating pumps, low-water fuel cutoffs, valves, gages, etc. It also covers fuels; fuel burning equipment and burner controls; water treatment; and boiler operation, maintenance, and repair.

Section VII, Recommended Guidelines for the Care of Power Boilers

This volume of so-called recommended guidelines is also a nonmandatory compendium of what is considered good practice in the industry. Section VII is, in a sense, a child of Section I, since a subgroup of BPV I, the Subgroup on Care of Power Boilers, used to write Section VII for review and eventual approval by its parent committee. The Subgroup on Care of Power Boilers revised Section VII infrequently, with the last major rewrite being in the early 1980s. No significant changes have been made to the text since then. In 1996 the Subgroup was disbanded and its duties were turned over to the Subgroup on General Requirements, where a task group was assigned to review Section VII for updating, as appropriate.

Section VII has a preamble that describes its purpose and contents quite well. The stated purpose of the guidelines is to promote safety in the use of power boilers. The guidelines are intended for use by those di-

rectly responsible for operating, maintaining, and inspecting power boilers. The emphasis of the guidelines is on industrial-type boilers because of their widespread use. Section VII is divided into nine subsections, as follows:

- C1. Fundamentals
- C2. Boiler Operation
- C3. Boiler Auxiliaries
- C4. Appurtenances
- C5. Instrumentation, Controls, and Interlocks
- C6. Inspection
- C7. Repairs, Alterations, and Maintenance
- C8. Control of Internal Chemical Conditions
- C9. Preventing Boiler Failures

Few engineers have the opportunity to gain first-hand experience in boiler operation, maintenance, and repair. Section VII provides a good alternative to such experience. It is recommended to those interested in expanding their knowledge about boiler operation, maintenance, and repair.

Section VIII, Rules for Construction of Pressure Vessels

This is a well-known and important ASME Code book. Years ago the title of Section VIII was Unfired Pressure Vessels (that is the origin of the U symbol used to stamp Section VIII vessels), but it is now called Rules for Construction of Pressure Vessels, since it covers fired as well as unfired vessels. Section VIII now comes in three volumes, Division 1 (the regular rules) and Division 2, Alternative Rules. A third volume, Division 3, Alternative Rules for Construction of High-Pressure Vessels was published in 1997. The Division 2 – Alternative Rules were completely rewritten in 2007. A list of some of the new technology produced for the VIII-2 rewrite includes:

- Adoption of a design margin on specified minimum tensile strength of 2.4,
- Toughness requirements,
- Design-by-rule for the creep range,
- Conical transition reinforcement requirements,
- Opening reinforcement rules,
- Local strain criteria for design-by-analysis using elastic-plastic analysis,
- Limit load and plastic collapse analysis for multiple loading conditions,
- Fatigue design for welded joints based on structural stress method, and
- Ultrasonic examination in lieu of radiographic examination.

A complete description of the new Section VIII – Division 2 may be found in ASME PTB-1-2009 entitled **ASME Section VIII – Division 2 Criteria and Commentary**.

Section VIII, Division 1 is a large volume and covers so many different types of vessels and forms of construction that only the briefest of overviews can be offered here. The Scope paragraph (U-1) explains a number of things. It notes that pressure vessels are containers for either external or internal pressure and that the pressure can come from an external source or be caused by the application of heat, or it can come from some combination of the two. The range of design pressure covered by Section VIII is from 15 psi (100 kPa) to no upper limit. Above 3000 psi (20.5 MPa) additional requirements are invoked.

Division 1 is divided into three Subsections, Mandatory Appendices, and Nonmandatory Appendices. Subsection A covers general requirements applicable to all pressure vessels. Subsection B covers specific requirements applicable to the various permitted fabrication methods, such as welding, forging, or brazing. Subsection C covers specific requirements applicable to the different classes of materials used in pressure vessel construction (such as carbon and low alloy steel, nonferrous metals, high alloy steels, cast iron, etc.).

The 34 mandatory appendices (designated as 1, 2, 3, etc.) cover a great variety of subjects including, among many others, design formulas, NDE methods, QC system requirements, and the design of expansion joints. The nonmandatory appendices (designated as A, B, C, etc.) cover another large group of interesting subjects, such as allowable loads on tube-to-tubesheet joints, illustrative examples of the application of code formulas and rules, preheating before welding, and design considerations for bolted flanges. One appendix, Appendix M, deals with the installation and operation of pressure vessels. Normally, installation and operation activities are the prerogative and responsibility of the local law enforcement authorities (sometimes called the jurisdiction) where the vessel is installed.

Appendix M treats a number of subjects: corrosion, access to vessel marking, pressure-relief valve installation and other aspects of overpressure relief. What is unusual is that Appendix M suggests what are, in effect, waivers of certain rules in the mandatory portion of the text of Section VIII (see paragraph M-1). Note that the waiver is conditioned on special permission for it being granted by the legal authority having jurisdiction over the installation of pressure vessels. An example of such a waiver is this: Paragraph UG-135(e) stipulates that (in general) there shall be no intervening stop valves between a vessel and its pressure-relieving device. However, appendix paragraph M-5.6(a) permits such an installation “for inspection and repair purposes only. When such a stop valve is provided, it shall be so arranged that it can be locked or sealed open, and it shall not be closed except by an authorized person who shall remain stationed there during that period of the vessel’s operation within which the valve remains closed, and who shall again lock or seal the stop valve in the open position before leaving the station.”

Appendix M also contains useful information on safety valve set pressures and the pressure-relieving capacities needed under fire conditions.

Section VIII, Division 1 covers a great variety of vessel types, and provides many more design rules and details than does Section I. Although the general design approach and system of Code construction under third-party inspection employed by both these sections are quite similar, some differences are worth noting:

1. Section VIII has far more materials available.
2. Section VIII permits the use of austenitic stainless steel in water-wetted service. Section I limits such use, due to a concern for the likelihood of IGSCC (intergranular stress corrosion cracking) caused by the concentration of even minute amounts of dissolved chlorides where boiling takes place.
3. Section I permits the design of vessels for only one maximum allowable level of stress and requires that the long seam of a vessel be volumetrically examined. For ordinary service (as opposed to what is known as lethal service), Section VIII varies the allowable stress level (by means of a so-called joint efficiency) in accordance with the amount of radiographic examination provided and the type of weld joint used. For example, a fully radiographed double-welded butt joint would have the same basic allowable stress in both Sections I and VIII. However, Section VIII provides the option of spot radiography or no radiography, in which cases the basic allowable stress is penalized by 15% and 30%. That is, joint efficiencies of 0.85 and 0.70 are imposed in the design formula used to establish vessel thickness.
4. The Scope paragraph of Section VIII, paragraph U-1, contains a number of interesting exemptions. Vessels with internal or external operating pressures not exceeding 15 psi fall outside the scope of Section VIII. So do “vessels having an inside diameter, width, height, or cross section diagonal not exceeding 6 in., with no limitation on length of vessel or pressure.” This latter provision can be used to exempt such components as small-diameter heat exchange coils from Code coverage. There is a converse to the above situation: any exempt vessel can be built and stamped to the Code if it meets the Code rules.
5. Differing from Section I (whose components are usually warm when under design pressure), Section VIII in the mid-1980s imposed a requirement that a minimum design metal temperature (MDMT) be established and marked on every vessel. This is the lowest temperature

at which it is safe to apply a specified design pressure without fear of brittle fracture due to the metal temperature being too close to the temperature at which its behavior changes from ductile to brittle. The designer must choose the MDMT based on the circumstances anticipated. If the choice of material and MDMT fails to satisfy certain exemption curves in paragraph UCS-66, impact tests are required to demonstrate that the material has adequate fracture toughness at the MDMT. Also differing from Section I practice, Section VIII recommends a minimum hydrostatic test temperature 30°F (16°C) above the minimum design metal temperature, where there is little danger of brittle fracture.

6. Postweld heat treatment rules in Section VIII are more lenient than those in Section I for P No. 1 materials (plain carbon steel).
7. On one question Sections I and VIII agree: Vessels known as unfired steam boilers can be built to either section. See discussion in Chapter 1.

Section IX, Welding and Brazing Qualifications

This section also has a subtitle: Qualification Standard for Welding and Brazing Procedures, Welders, Brazers, and Welding and Brazing Operators. It is a challenge to provide a simple, clear, and concise description of Section IX: Some general prefatory remarks may help. Ever since welding began to replace riveting as a means of joining together the plates and heads comprising pressure vessels, it has been recognized that the welds were potential weak points. Thus, the goal in welding has always been the achievement of sound welds, welds that are as strong as the base metal being joined. Today, the ASME approaches this goal in a two-step process. It first requires a manufacturer to develop and qualify a so-called Weld Procedure Specification (WPS), and thus prove that the particular procedure produces satisfactory welds. It then requires the individual welders to prove that they have the ability to produce sound welds when using a qualified weld procedure. Thus the welding must be done using qualified welders and qualified weld procedures. Moreover, a welder must have proven his or her ability (been qualified) for each process he or she uses. With this explanation in mind, it is possible to use the following excerpts from the Introduction to Section IX to explain its purpose and organization:

Section IX of the ASME Boiler and Pressure Code relates to the qualification of welders, welding operators, brazers, and brazing operators, and the procedures employed in welding or brazing in accordance with the ASME Boiler and Pressure Vessel Code and the ASME B31 Code for Pressure Piping. Section IX is a document referenced for qualification by various construction codes such as Section I, III, IV, VIII, etc. These particular construction codes apply to specific types of fabrication and may impose additional welding requirements or exemptions from Section IX qualifications. Qualification in accordance with Section IX is not a guarantee that procedures and performance qualifications will be acceptable to a particular construction code.

The purpose of the Welding Procedure Specification (WPS) and Procedure Qualification Record (PQR) is to determine that the weldment proposed for construction is capable of having the required properties for its intended application. It is presupposed that the welder or welding operator performing the welding procedure qualification test is a skilled workman. The procedure qualification test is to establish the properties of the weldment or brazement and not the skill of the personnel performing the welding or brazing. In addition, special consideration is given when notch toughness is required by other Sections of the Code. The notch-toughness variables do not apply unless referenced by the construction codes.

In Welder or Brazer/Brazing Operator Performance Qualification, the basic objective is to determine the ability to deposit sound weld metal, or to make a sound braze. In Welding Operator Performance Qualification, the basic criterion is to determine the mechanical ability of the welding operator to operate the equipment.

Section IX describes each welding process in terms called variables that affect the welding. Examples of variables include the type of welding, thickness of metal being joined, P-number (a means of categorizing material), and postweld heat treatment.

Section IX is divided into two parts: welding and brazing. Each part is then divided into four articles, as follows:

- a. General requirements (Article I Welding and Article XI Brazing)
- b. Procedure qualifications (Article II Welding and Article XII Brazing)
- c. Performance qualifications (Article III Welding and Article XIII Brazing)
- d. Data (Article IV Welding and Article XIV Brazing)

These articles contain general references and guides that apply to procedure and performance qualifications. They explain the manufacturer's responsibilities, the type and purpose of the various mechanical tests used in procedure and performance qualification, and acceptance criteria for those tests. Also listed are the welding variables used in procedure and performance qualification.

The subject of welding and further explanation of Section IX can be found in Chapter 6.

Section X, Fiber-Reinforced Plastic Vessels

This section of the Code provides construction rules for plastic vessels, which have advantages over metal vessels in special circumstances. These fiber-reinforced plastic pressure vessels have excellent corrosion resistance, they are light in weight, and are advantageous in certain processes where great purity and cleanliness is required. They can, with relative ease, be made in very odd or unusual shapes by using inexpensive wooden forms to shape them.

The fibers used for reinforcing are made of glass, Kevlar, or carbon. The plastic portion of the matrix is a thermoset resin.

The use of fiber-reinforced plastics for the manufacture of pressure vessels presents unique material considerations in design, fabrication, and testing. Metallic vessels, made from materials that are normally isotropic and ductile, are designed using well established allowable stresses based on measured ductility and tensile properties. In contrast, fiber-reinforced plastics are usually anisotropic, and the physical properties are dependent upon the fabrication process, the placement and orientation of the reinforcement, and the resin matrix.

It is not possible to fabricate a fiber-reinforced plastic pressure vessel of a single basic material for which there is an ASTM specification. The vessel parts are made up of various basic materials, such as fiber reinforcement and resin, which are joined in the presence of a catalyst to create a composite material that is formed into a vessel or vessel part by a specified process. The composite material will often have directional properties that must be considered in design.

Fiber-reinforced plastic vessels are designed by one of two basic methods:

- a. Class I Design — Qualification of a vessel design by pressure testing one or more prototype vessels. This testing is done in two stages. First, the pressure is cycled from atmospheric pressure to design pressure 100,000 times. No leakage may occur during this stage. Second, following a successful pressure cycling test, the vessel is subjected to another pressure test, really a proof test, to determine its so-called qualification pressure. This pressure must be at least six times the vessel design pressure. Thus the prototype has proven the design is acceptable if it can sustain 100,000 full design pressure cycles and still contain a pressure six times the design pressure. This particular prototype vessel may not be stamped and put into service, since it can be considered used, and well used at that. Subsequent duplicate vessels must be built in strict accordance with the procedure specification used in fabricating the prototype, to assure that they will be as good as the prototype. These Class I vessels are often mass-produced.
- b. Class II Design — Code-specified mandatory design rules followed by nondestructive examination and acceptance testing using acoustic emission testing while the vessel is subjected to

programmed increasing stress levels up to the stress caused by 1.1 times design pressure. No leakage is permissible during the acceptance testing.

Occasionally, some part of one of these plastic vessels is made of metal, for example, to facilitate a bolted attachment. In such cases, the metal parts must be constructed in accordance with Section VIII.

Section XI, Inservice Inspection of Nuclear Plant Components

Normally the ASME Code covers new construction only. Section XI is the major exception; it provides rules for the examination, testing, and inspection of components and systems in operating (or shut down) nuclear power plants. The application of Section XI rules begins when the construction of the plant is completed, that is, they begin where Section III rules leave off. Unlike Section VI and Section VII, which are only suggested rules for the care and maintenance of heating and power boilers, the Section XI rules are mandatory requirements for maintaining a nuclear power plant and for safely and quickly returning it to service following outages. The rules provide for a program of periodic examination, testing, and inspection, to furnish ongoing evidence of safety. The rules also stipulate duties of the Authorized Nuclear Inservice Inspector in order to verify the successful completion of the programmed inspection and testing and permit the plant to return to service.

Section XI has three major divisions, dealing with the three major types of nuclear power plants: lightwater cooled plants, gas-cooled plants, and liquid-metal cooled plants. For light-water cooled plants, some of the major headings covered are these:

- General Requirements
- Requirements for Class 1 Components
- Requirements for Class MC Components (the metal containment vessels or liners)
- In-service Testing of Pumps
- In-service Testing of Valves

Just within the category of General Requirements are these major headings:

- Scope and Responsibility
- Examination and Inspection
- Standards for Examination Evaluation
- Repair and Replacement
- System Pressure Tests
- Records and Reports

Section XI uses techniques such as flaw growth analysis to determine acceptability of components for continued service. Section XI also provides detailed repair procedures and permits temper bead welding to obviate postweld heat treatment. The inspections and tests are scheduled on a 10-yr cycle. Some inspections or tests may be required only once in 10 years; others are more frequent.

An unusual aspect of Section XI is that the edition in effect when the plant was completed may continue to be used, or the owner may choose a later or the latest edition. However, the Nuclear Regulatory Commission (NRC) requires owners to update their inspection and testing program to the latest edition of Section XI endorsed by the NRC (now the 2004 Edition). The update has to be completed by the beginning of the next 10-yr inspection cycle.

Section XII, Rules for Construction and Continued Service of Transport Tanks

The large tanks used to transport hazardous materials have long been governed by U.S. Department of Transportation regulations. In 1997, the ASME formed a new committee, BPV XII, to develop a new Code section,

Section XII. Issued in 2004, this section provides rules for the design, construction, and continued operation of tanks used to carry hazardous goods by all means of transport (road, rail, air, and sea).

This section has 10 parts addressing:

1. General requirements applicable to all transport tanks
2. Material
3. Design
4. Welding
5. Fabrication
6. Examination
7. Testing
8. Pressure-relief devices
9. Stamping, certification and records
10. Repair, alteration, testing and inspection for continued service

It also contains what are called Modal Appendices. These appendices provide specific detailed requirements applicable to cargo tanks, rail tanks, portable tanks, and ton tanks. The text and modal appendices are supplemented by 13 mandatory and 7 nonmandatory appendices covering, among others, such subjects as quality control, NDE methods, adhesive attachment of nameplates, cryogenic transport tanks, and use of U.S. customary and SI units.

ASME Code for Pressure Piping, B31

This is a large code, covering many types of piping. Individual code sections are the following:

- B31.1 Power Piping
- B31.3 Process Piping
- B31.4 Liquid Transportation Systems for Hydrocarbons
- B31.5 Refrigeration Piping
- B31.8 Gas Transmission and Distribution Piping Systems
- B31.9 Building Services Piping
- B31.11 Slurry Transportation Piping Systems

A related manual is *Manual for Determining the Remaining Strength of Corroded Pipelines: A Supplement to B31, Code for Pressure Piping*.

The two sections of the piping code most used in association with power boilers are B31.1, Power Piping, and B31.3, Process Piping. These are briefly described below.

B31.1, Power Piping

The Power Piping Code is intended for use in conjunction with Power Boilers, Section I of the ASME Code. The stated philosophy of B31.1 is to parallel the provisions of Section I as they can be applied to power piping systems. The allowable stress basis for both codes is the same. Some engineers feel that B31.1 is a more conservative piping code than some other piping codes, and its foreword states that this reflects the need for long service life and maximum reliability in power plant installations. However, it is arguable that other codes (B31.3, for example) achieve comparable conservatism through other means. The foreword to B31.1 also notes that the Code often warns a piping designer, fabricator, or erector against possible pitfalls, but that it is not a handbook and cannot substitute for education, experience, and sound engineering judgment. (Similar advice was recently added to the forewords of Sections I through XII of the ASME Code.) The foreword to B31.1 goes on to explain that “a designer who is capable of a more rigorous analysis than is specified in the Code may justify a less conservative design, and still satisfy the basic intent of the Code.” This provision can

sometimes be very valuable, provided the designer is able to demonstrate the validity of his or her approach and obtain its acceptance by oversight or regulatory personnel.

Sometimes, it is not clear which section of the B31 piping code covers a specific piping system. In the early 1990s, the introduction to the Piping Code was revised to note that in such cases the owner or user may choose any section determined to be generally applicable, with the caveat that additional requirements may be necessary to provide a safe system. The Introduction to B31.1 says of such choices: "Technical limitations of the various sections, legal requirements, and possible applications of other codes or standards are some of the factors to be considered by the user in determining the applicability of any section of this Code."

As explained in its introduction, the major topics covered by B31.1, Power Piping are these:

1. Requirements for design of components and assemblies, including pipe supports
2. Requirements and data for evaluation and limitation of stresses, reactions, and movements associated with pressure, temperature changes, and other forces
3. Guidance and limitations on the selection and application of materials, components, and joining methods
4. Requirements for the fabrication, assembly, and erection of piping
5. Requirements for examination, inspection, and testing of piping
6. References to acceptable material specifications and component standards, including dimensional requirements and pressure-temperature ratings

The design rules of B31.1 are little changed from those of the 1955 edition of the Code for Pressure Piping, in which Chapter 1 set forth rules for Power Piping. Some consider them to be conservative, but others defend this conservatism by noting that there is no assurance that the power piping systems covered by B31.1 will receive adequate long-term inspection, maintenance, and repair. Moreover, personnel working near these exposed piping systems are at risk from any failures. This contrasts with the possibly less hazardous situation of a tube failure within the boiler enclosure. The basic design approach used in the B31.1 code is to size piping components for internal pressure, using formulas and stresses very similar to those in Section I. The allowable stresses appear, conveniently, in the appendix.

B31.1 sizes components for internal pressure based on an allowable circumferential stress (that stress is a membrane stress). Longitudinal stress due to the combined effects of pressure, weight and other sustained loads is limited to the basic allowable stress in tension at design temperature. A separate calculation, with a higher allowable stress, is used to limit the stresses due to bending moments caused by cyclic loads (most often due to thermal expansion of the piping system). A simplified fatigue analysis applies if more than 7000 cycles of thermal expansion stress are anticipated, and reduces the allowable stress range in proportion to the number of stress cycles above 7000. At 100,000 cycles or more, the so-called stress range reduction factor reaches a minimum value of 0.5. However, the value of 0.5 should not be construed as establishing an endurance limit, suitable for evaluation of high cycle vibration stress.

B31.1 has a category known as Occasional Loads (paragraph 104.8.2). When occasional loads are combined with sustained loads, the allowable stress is increased by as much as 20%, depending on the duration of the occasional load. Thus stresses up to 20% higher than normally allowed are permitted for short-term loadings, such as those produced by seismic events, in combination with other, sustained loads.

B31.1 contains 14 mandatory and nonmandatory appendices covering allowable stresses, materials data (coefficients of thermal expansion and elastic moduli), flexibility and stress intensification factors for various piping components and configurations, and reference standards. There is a nonmandatory appendix, Appendix II that deals with safety valve installations, including the calculation of safety valve discharge forces. Other nonmandatory appendices deal with nonmetallic piping, corrosion control, and design of restrained underground piping. Also included is a useful 12-page section, Recommended Practice for Operation, Maintenance, and Modification of Power Piping Systems. Like the book sections of the Boiler and Pressure Vessel Code, B31.1 issues Code Cases and Interpretations, and these are issued with the B31.1 Code as a supplement.

B31.1 has the technical responsibility for the rules covering materials, design, fabrication, installation and testing of certain boiler piping known as boiler external piping. This situation is explained in Chapter 4.

B31.3, Process Piping (Until 1996 Known as Chemical Plant and Petroleum Refinery Piping)

This piping code dates from 1959, when the refinery chapter (Chapter 3 of the Code for Pressure Piping) emerged as a stand-alone document, Petroleum Plant Piping. In 1976, a draft Code section for Chemical Plant Piping was merged with the existing Code Section for Petroleum Plant Piping and renamed B31.3, Chemical Plant and Petroleum Refinery Piping. In 1980, B31.3 assimilated a draft Code section for Cryogenic Piping, and in 1996, the name of the document was simplified to Process Piping. As can be seen from its introduction, B31.3 is in many respects similar to B31.1, but there are notable differences. Different criteria are used in setting allowable stresses, which are essentially the same as those used in Section VIII, Division 2 for temperatures below the creep range and the same as Division 1 stresses for temperatures within the creep range. (See 302.3.2 of B31.3 for further particulars.) In general, B31.3 takes a broader approach to piping design than B31.1, since it deals with a greater variety of piping applications. It covers a variety of fluid services, with different requirements for each service, depending on how dangerous the fluid is considered to be. Categories of fluid service (e.g., Category M fluid service) are established to describe the combination of fluid properties (e.g., reduced hazard, flammable, toxic), operating conditions (low or high pressure and/or temperature), and other factors that establish different bases for the design of a piping system. B31.3 in its paragraph 300(b) establishes the responsibilities of six entities involved in the construction of a process piping system. These are the owner, the designer, the manufacturer, the fabricator, the erector of the system, and the owner's inspector. In particular, the owner has overall responsibility for compliance with the B31.3 Code, for establishing all requirements necessary for compliance, and for designating the piping into appropriate categories of fluid service.

In its scope, paragraph 300.1.1, B31.3 with some exceptions asserts coverage for all fluids, including:

1. Raw, intermediate, and finished chemicals
2. Petroleum products
3. Gas, steam, air, and water
4. Fluidized solids
5. Refrigerants

One difference between B31.3 and B31.1 is that the former establishes hardness limits for welds. This is provided as a means of assuring that the postweld heat treatment was carried out properly and to prevent certain types of stress corrosion cracking such as in what is known as sour oil service. These limits require testing to determine hardness and also present the problem of what to do when the weld is too hard. This problem has yet to be resolved short of removing and replacing the weld and effected base material.

APPENDIX IV

DESIGN EXERCISES

DESIGN EXERCISE NO. 1, DESIGN OF A HEADER

This first problem illustrates the use of Section I's method of design-by-rule, using the rules of PG-27 to design a header. The reader is advised to review Chapter 4 and PG-27 before attempting to solve the problem or looking at the solution. When reviewing PG-27, note that slightly different formulas are used for designing pipe and tubes.

It has been decided to make a certain cylindrical header from pipe, using 10-inch nominal pipe size (NPS) of appropriate wall thickness for a maximum allowable working pressure of 1020 psi. Applying Section I formula PG-27.2.2 with a 10.75-inch outside diameter and an allowable stress of 10,800 psi (at an 800°F design temperature) for SA-106 Grade B pipe material, determine the minimum wall thickness required. Then select the lightest pipe adequate for this design pressure from a table showing standard pipe sizes and wall thickness varying according to schedule number. Assume the constant C (for threading and structural stability) in formula PG-27.2.2 is zero, and determine the temperature coefficient y from the table in Note 6 of PG-27.4.6. Assume also that no corrosion allowance is needed, that the hydrostatic head which normally must be included in the design pressure when designing pipe is negligible in this case, and that there are no openings or connections which would require compensation or ligament efficiency calculations. For ready reference, PG-27 and a table of pipe sizes have been included at the end of this appendix.

SOLUTION TO DESIGN EXERCISE NO. 1

After using Note 1 of PG-27.4.1 to determine the efficiency, E , for seamless pipe to be 1.00, Note 3 of PG-27.4.3 to verify that the constant C is zero, and the table in Note 6 of PG-27.4.6 to determine the temperature coefficient y to be 0.4, we have all factors needed to solve formula PG-27.2.2. We can then find from that formula that the minimum thickness required is 0.49 in., as follows:

$$t = \frac{PD}{2SE + 2yP} + C = \frac{(1020)(10.75)}{2(10800) + 2(0.4)(1020)} = 0.49 \text{ inches}$$

We now go to a standard table of pipe sizes and thickness that derives from ASME Standard B36.10M, Welded and Seamless Wrought Steel Pipe. Note that for any diameter, the wall thickness varies in accordance with the so-called schedule number of the pipe. The table shows that schedule 60 (formerly called extra-strong) NPS 10 appears to have just about the wall thickness we need: 0.50 in. However, this is *not* the case, because the thickness listed in the table is nominal and is subject to an undertolerance, as explained in Note 7 of PG-27.4.7. This 12.5% undertolerance on thickness is given in ASME Specification SA-530 covering general requirements for carbon and alloy steel pipe. It is also found in the individual pipe specifications listed in PG-9, for example, in paragraph 19.3 of the SA-106 pipe specification. Accordingly, we must go to the next commonly available wall thickness among the specifications approved by ASME: Schedule 80, with a nominal wall thickness of 0.594 in. Even with an undertolerance of 12.5%, the minimum thickness at any point in this pipe would be $0.875 \times 0.594 \text{ in.} = 0.52 \text{ in.}$, which satisfies our required minimum of 0.49 in. Our final choice would therefore be an NPS 10 schedule 80 SA-106 Grade B pipe of whatever length is required.

DESIGN EXERCISE NO. 1A, ALTERNATIVE DESIGN OF HEADER (A-317)

PG-27.1 permits the use of the equations given in A-317 of Appendix A in lieu of the equations provided in PG-27 for the calculation of cylindrical components under internal pressure (see Chapter 4 for the explanation and history of A-317).

SOLUTION TO DESIGN EXERCISE NO. 1A

Using the same parameters as used in Design Exercise No.1, calculate the required header thickness using the equations in Appendix A-317. The minimum required thickness of the header may be calculated from the formula shown in A-317.2.1, as follows:

$$t = D(1 - e^{(-P/SE)})/2 + C + f$$

Where: D = outside diameter of cylinder = 10.5 in.

C = minimum allowance for threading and structural stability

(see A-317.3, Note 3) = 0

E = efficiency (see A-317.3, Note 3) = 1.0

e = the base of natural logarithms = 2.718281828

P = maximum allowable working pressure = 1020 psi

S = maximum allowable stress value at design temperature = 10,800 psi

E = efficiency (see A-317.3, Note 1)

f = thickness factor for expanded tube ends (see A-317.3, Note 4)

$$t = 10.5 \times (1 - 2.718281828^{(-1020/10800)})/2 = 0.48 \text{ in.}$$

Note that the first part of the equation is only divided by 2. The terms C and f are additive. In our example they are both equal to zero.

DESIGN EXERCISE NO. 2, DESIGN OF A HEAD

Design Exercise No. 1 consisted of the design of a cylindrical header, which turned out to be an NPS 10 schedule 80 SA-106 Grade B pipe (with a 10.75-in. OD and a nominal wall thickness of 0.594 in.). In this exercise, various heads for that header will be designed, starting with a so-called dished head, using the rules of PG-29.1. (Dished heads are usually standard catalog items furnished as standard pressure parts under the rules of PG-11.) Again, the reader is advised to review the portion of Chapter 4 dealing with dished heads, and PG-29, before proceeding. For ready reference, PG-29 is also included at the end of this appendix.

- (A) For the same maximum allowable working pressure of 1020 psi and design temperature of 800°F, determine the required thickness of a blank unstayed dished head with a 10-inch radius L on the concave side of the head. Assume the head is made of SA-516 Grade 70 material. The maximum allowable working stress, S , from Section II, Part D is determined to be 12,000 psi. Verify this value if you have a copy of Section II, Part D available. Notice that the allowable stress for this material is higher than that of the pipe material.
- (B) PG-29.7 provides a rule for the design of a semiellipsoidal shaped head. What minimum thickness would be needed if this type of head were used?
- (C) PG-29.11 provides the rules for designing a full hemispherical shaped head. What minimum thickness would be required if this type of head were used?

SOLUTION TO DESIGN EXERCISE NO. 2 (A)

$$t = \frac{5PL}{4.8S} = \frac{5(1020)(10)}{4.8(12,000)} = 0.89 \text{ inches}$$

SOLUTION TO DESIGN EXERCISE NO. 2 (B)

$$t = 0.49 \text{ in.}$$

Explanation: PG-29.7 says that a semiellipsoidal head shall be *at least as thick as the required thickness of a seamless shell of the same diameter*. Thus, the answer derived in Design Exercise No. 1 applies.

SOLUTION TO DESIGN EXERCISE NO. 2 (C)

$$t = \frac{PL}{2S_w - 0.2P} = \frac{1020(10.75/2 - 0.594)}{2(12000) - 0.2(1020)} = 0.21 \text{ inches}$$

Note that L is the inside radius of the head. In this case, it was chosen to match the nominal inside radius of the piece of pipe used for the shell in Design Exercise No. 1.

Also note that w is the weld strength reduction factor (see PG-26) which in this case = 1.0

From the results of these three head thickness calculations, it is clear that the hemispherical head is the most efficient shape, requiring a thickness only a fraction of that required for a dished or an ellipsoidal head, and only about half that of the header to which it is attached. This is because a hemispherical head carries pressure loads by developing predominantly membrane stresses, while the ellipsoidal and especially the dished heads develop significant bending stresses in addition to the membrane stresses.

Note also that PG-16.3 establishes the minimum thickness of boiler plate under pressure as 1/4 inch in most cases.

DESIGN EXERCISE NO. 3, CHOICE OF FEEDWATER STOP VALVE

In Chapter 11, under the heading Valves and Valve Ratings, it was explained that most boiler valves are furnished in compliance with the ASME product standard for valves, ASME B16.34, Steel Valves — Flanged, Threaded, and Welding End. This standard provides a series of tables, for various material groups, giving pressure-temperature ratings according to what are called pressure classes. The classes typically vary from the 150 class (the weakest) to the 4500 class. For each class, the allowable pressure is tabulated as a function of temperature. The allowable pressure at any temperature is the pressure rating of the valve at that temperature. Temperatures range from the lowest zone, -20°F to 100°F , to 850°F and higher, depending on the material group. The allowable pressure for the valve falls with increasing temperature, since it is based on the allowable stress for the material.

Also as explained in Chapter 11, the designer of a valve for Section I service must select a valve whose pressure rating at design temperature is adequate for the maximum allowable pressure (MAWP) of the boiler. However, feedwater and blowoff piping and valves are designed for a pressure higher than the MAWP of the boiler because they are in a more severe type of service called shock service. This complicates the choice of valve somewhat, and to clarify the choice, the committee issued Interpretation I-83-91, which is discussed in Chapter 11. The following example illustrates the choice of a feedwater stop valve following the procedure outlined in the fourth reply of that interpretation.

The problem here is to select a feedwater stop valve for a boiler whose maximum allowable working pressure (MAWP) is 1500 psi. Note that the design rules for a valve that is part of the boiler external piping are found in paragraph 122 of B31.1, Power Piping.

SOLUTION TO DESIGN EXERCISE NO. 3

The first step in this problem is to determine the design pressure and temperature required for this valve. By paragraph 122.1.3 of B31.1, the design pressure of a feedwater valve must exceed the MAWP of the boiler by 25% or 225 psi, whichever is the lesser:

$$1500 \text{ psi} + 225 \text{ psi} = 1725 \text{ psi}$$

$$1500 \text{ psi} \times 1.25 = 1875 \text{ psi}$$

The design pressure P_F is taken as the lesser value, 1725 psi.

The design temperature is found from paragraph 122.1.3(B) of B31.1 to be the saturation temperature of the boiler. That temperature for a MAWP of 1500 psi is found from any steam table to be 596°F. Thus, we must now find a valve designed for 1725 psi at 596°F.

Next turn to the tables of valve materials and ratings from the governing valve standard ASME B16.34, Valves — Flanged, Threaded, and Welding End (for ready reference, these pages are included at the end of this appendix). Assume the valve material is a forging, SA-105, which is a carbon steel suitable for the relatively low temperature of feedwater service. Notice that the standard uses the ASTM designation A-105. It is seen from the Table 1 list of material specifications that A-105 falls in what is known as material group 1.1.

The task now is to find the lowest valve class adequate for the design conditions we have established. Turning to Table 2-1.1, the ratings for group 1.1 materials, we enter with the design temperature, rounded up to 600°F (315°C), and look for a valve class adequate for 1725 psi (119 Bar). The first such class is a 1500 (standard class) valve. However, an alternative choice is available from the ratings table for special class valves. From that table, it is seen that a 900 special class valve would also be adequate. (Remember that the difference between the ratings of these two classes is based on the amount of NDE used in their manufacture.) The final choice of valve then becomes one of cost and delivery time.

DESIGN EXERCISE NO. 4, DESIGN OF A TUBE FOR LUG LOADING

The PW-43 method for determining the allowable load on a tube lug is explained in Chapter 4, under the heading Loading on Structural Attachments. When PW-43 was revised in 1992, the sample problems in the Section I Appendix paragraphs A-71 to A-74 illustrating the determination of allowable loading on tube lugs were revised to show the new method. The first of the sample problems, that shown in A-71, is explained here to serve as a guide to the method. The problem is described as follows.

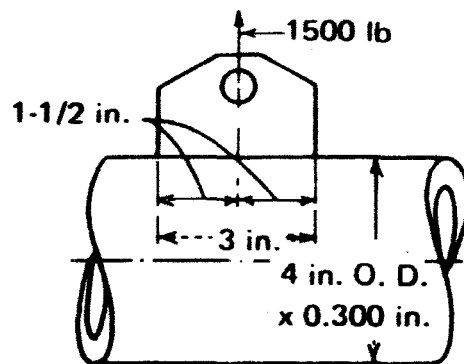


FIGURE A-71
LUG LOAD ON TUBE
(REPRODUCED FROM ASME SECTION I)

A tube is suspended by a welded attachment with a 1500-lb. design load and the dimensions shown in Fig. A-71. This is a condition of direct radial loading on the tube. The allowable lug loading is calculated for the following conditions:

Tube material is SA-213 T-22

MAWP = 2258 psi

$T = 800^{\circ}\text{F}$

Tube diameter, $D = 4.0$ in.

Tube wall thickness, $t = 0.30$ in.

Lug thickness = $\frac{1}{4}$ in.

Lug attachment angle (the angle subtended by the lug width, see Table PW-43.1) = 7° .

Design stress for tube, $S_a = 16,600$ psi

SOLUTION TO DESIGN EXERCISE NO. 4

The first step in the solution to this problem is to determine K , the tube attachment angle design factor, by interpolation in Table PW-43.1. K is found to be 1.07. Also needed is the value of the variable X , which is defined in PW-43.2. In this example,

$$X = D/t^2 = (4.0/0.3^2) = 44.4$$

The load factor L_f is now determined, either by reading it from the plot in Fig. PW-43.2 or by using the appropriate load factor equation in PW-43.2.1 or PW-43.2.2, depending on whether the lug is applying tension or compression loading to the tube.

The load factor equations are as follows:

For compression loading,

$$L_f = 1.618X^{[-1.020 - 0.014(\log X) + 0.005(\log X)^2]}$$

For tension loading,

$$L_f = 49.937X^{[-2.978 + 0.898(\log X) - 0.139(\log X)^2]}$$

In either case, the load factor is a function of X , which has already been determined to be 44.4. It is hard to read the plot with an accuracy greater than two significant figures (which ought to be good enough for the design of a tube lug). However, if the equations are used, greater accuracy can be obtained. Note that the log terms in the equations are logarithms to the base 10. Substituting $X = 44.4$ in those equations gives a tension load factor $L_f = 0.0405$ and a compression load factor $L_f = 0.0326$. The problem as stated concerns a tension load on the lug, but the values of both load factors are derived in order to illustrate that there can be a significant difference in allowable load, depending on the direction of the load.

The next step is to determine S_t , the amount of the allowable stress that is available for the lug loading. S_t is found from the equation in PW-43.2.3:

$$S_t = 2.0S_a - S$$

S_t is thus seen to be twice the allowable tube stress less the membrane pressure stress, S , at MAWP determined from equation PG-27.2.1.

$$S = P/[(2t - .01D - e)/(D - (t - .005D - e))]$$

$$S = 2258/[(2 \times 0.3 - 0.01 \times 4)/(4 - (0.3 - .005 \times 4))] = 15,000 \text{ psi}$$

Note: $e = 0$ (see PG-27.4, Note 4)

(Notice that if there were no stress due to pressure, equation PW-43.2.3 would give a value of S_t equal to twice the allowable membrane pressure stress. This is not unreasonable because the bending stress in the wall

of the tube caused by lug loading is considered a secondary bending stress.) In the present example, S is found to be 15,000 psi (see calculation above). Thus

$$S_t = 2(16,600) - 15,000 = 18,200 \text{ psi}$$

L_a , the maximum allowable unit load on the attachment, can now be determined from equation PW-43.2.4:

$$\text{Tension } L_a = K(L_r)S_t = (1.07)(0.0405)(18200) = 788 \text{ lb/in.}$$

The comparable unit load in compression is:

$$\text{Compression } L_a = K(L_r)S_t = (1.07)(0.0326)(18200) = 635 \text{ lb/in.}$$

Since the design load is 1500 lb in tension, applied at the center of a 3-in.-long lug, the actual unit load is only 500 lb/in., which is less than the maximum permitted. The design is thus seen to be satisfactory.

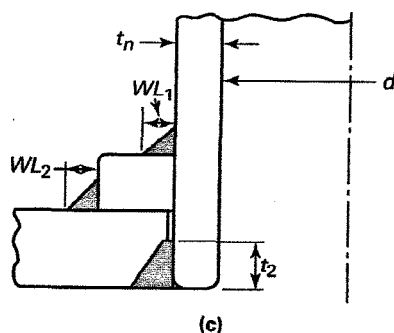
DESIGN EXERCISE NO. 5, DESIGN OF AN OPENING

Design Exercise No. 1 consisted of the design of a cylindrical header, which turned out to be a NPS 10 schedule 80 SA-106 Grade B pipe. We propose to add a 6-in. reinforced opening, generally as shown in Fig. PW-15, sketch (c). For the purpose of this exercise we will select a NPS 6 x-stg. SA-106 Grade B pipe, arranged as mentioned above.

Initially we will calculate the required opening reinforcement using Fig. PG-33.1. It is suggested the reader review PG-33 COMPENSATION REQUIRED FOR OPENINGS IN SHELLS AND DISHED HEADS before proceeding with this design exercise. After we have established the size of the reinforcing pad, we will check the attachment welds for adequacy following the rules of PG-37 and Fig. PW-15.

SOLUTION TO DESIGN EXERCISE NO. 5

The attachment is a 6-in. x-stg. pipe having an outside diameter, D , of 6.625 in. The nominal wall thickness is 0.432 in. (Note that when a pipe is used for a nozzle attachment, we use the nominal wall thickness for the



For sketch (c):

(1) Required weld strength (PG-37.2):

$$W = (A - A_1)S_v$$

Weld strength = WL_2 in shear + t_2 in tension

$$= 0.49 \left(\frac{1}{2} \right) WL_2 \pi (D_p + WL_2) S_v f_{r3} + 0.74 \left(\frac{1}{2} \right) t_2 \pi (d + 2t_n) S_v f_{r1}$$

(2) Check nozzle to pad and shell (PG-37.3):

$$W = (A - A_1 - A_{42} - A_5)S_v$$

Weld strength = WL_1 in shear + t_2 in tension

$$= 0.49 \left(\frac{1}{2} \right) WL_1 \pi (d + 2t_n + WL_1) S_v f_{r1} + 0.74 \left(\frac{1}{2} \right) t_2 \pi (d + 2t_n) S_v f_{r1}$$

FIG. PW-15
EXAMPLES OF WELD STRENGTH CALCULATIONS
SKETCH (C)
(REPRODUCED FROM ASME SECTION I)

opening reinforcement calculations, following the precedent set in the sample calculations A-68 and A-70). The diameter of the finished opening, d , is $6.625 - (2 \times 0.432) = 5.761$ in. From Design Exercise No. 1 we determined the design characteristics of the header to be $t = 0.52$ in., $t_r = 0.49$ in., design pressure, $P = 1020$ psi at 800°F , and design allowable stress, $S = 10,800$ psi.

Since the header material and the connecting pipe are to be fabricated from the same material (SA-106 Grade B) the terms f_{r1} and $f_{r2} = 1.0$ (see PG-33.3). The term $F = 1.0$ (see PG-33.3 and Fig. PG-33.3). The design allowable stress for the Pipe Header is $S_v = 10,800$ psi (see Design Exercise No.1). The design allowable stress for the reinforcing element is $S_p = 12000$ psi (see Section II, Part D for SA-516 Grade 70 at 800°F). $f_{r3} = S_p/S_v = 12000/10800 = 1.111$; however, f_{r3} cannot be greater than 1.0 (see PG-37.1) The minimum weld sizes per Fig. PW-16.1 are:

$$WL_1 = 0.7t_{\min} = 0.375 \text{ in.}; WL_2 = 0.5t_{\min} = 0.25 \text{ in.}$$

$$D_p = 2d - (2WL_2) = (2 \times 5.761) - (2 \times 0.25) = 11.022 \text{ in.}$$

Initially we will calculate the required minimum thickness for the nozzle using the formula from PG-27.2.2, where:

$$t_m = \frac{PD}{(2SE - 2yP)} + C = \frac{1020(6.625)}{2(10800 \times 1) - 2(.04)(1020)} + 0 = 0.301 \text{ in.}$$

The terms y and C are the same as was for Design Exercise No.1.

Next we will calculate the total cross-sectional area of compensation required A , the available area in shell A_1 , area available in the nozzle projecting outward A_2 , area available in outward nozzle weld A_{41} , Area available in outer element weld A_{42} , and the area available in element (see Fig. PG-33.1).

$$\begin{aligned} A &= (d + 2t_n)t_r F = (5.761 + (2 \times 0.432)) \times 0.49 \times 1 = 3.246 \text{ in.}^2 \\ A_1 &= (d - 2t_n)(t - Ft_r) = (5.761 - (2 \times 0.432)) \times (0.52 - (1.0 - 0.049)) = 0.147 \text{ in.}^2 \\ A_2 &= 2(t_n - t_m)(2.5f_{r1}) = 2 \times (0.432 - 0.301) \times (2.5 \times 0.52 \times 1.0) = 0.340 \text{ in.}^2 \\ A_{41} &= (WL_1)^2 f_{r2} = 0.375^2 \times 1.0 = 0.140 \text{ in.}^2 \\ A_{42} &= (WL_2)^2 = 0.25^2 \times 1.0 = 0.062 \text{ in.}^2 \\ A_5 &= (D_p - d - 2t_n)t_e f_{r3} = (11.022 - 5.761 - (2 \times 0.432)) \times 0.625 \times 1.0 = 2.748 \text{ in.}^2 \end{aligned}$$

Note: The thickness of the Reinforcing Element t_e was selected at 0.625 in. to meet the required cross-sectional area of compensation.

$$\begin{aligned} A_1 + A_2 + A_{41} + A_{42} + A_5 &= 0.147 + 0.340 + 0.140 + 0.062 + 2.748 = 3.437 \text{ in.}^2 \\ &> A = 3.246 \text{ in.}^2 \end{aligned}$$

Next, we will check that the welds have adequate strength to assure that the attaching welds can transmit the loads carried by the individual elements.

Figure PW-15 EXAMPLES OF WELD STRENGTH CALCULATIONS can be used as a guide for the required weld check calculations. Since our example was taken from sketch (c) the required weld strength is:

$$\begin{aligned} W &= (A - A_1)S_v \\ &= (3.246 - 0.147) \times 10800 = 33470 \text{ lbs.} \end{aligned}$$

$$\text{Weld strength} = WL_2 \text{ in shear} + t_2 \text{ in tension}$$

$$\begin{aligned} &= 0.49(1/2)WL_2\pi(D_p + WL_2)S_v f_{r3} + 0.74(1/2)t_2\pi(d + 2t_n)S_v f_{r1} \\ &= 0.49 \times 0.5 \times .25 \times \pi \times (11.022 + .25) \times 10800 \times 1 = 23425 \text{ lbs.} \\ &= 0.74 \times 0.5 \times 0.375 \times \pi \times (5.761 + (2 \times 0.432)) \times 10800 \times 1 = 31188 \text{ lbs.} \\ &= 23425 + 31188 = 54613 \text{ lbs.} > 33470 \text{ lbs.} \end{aligned}$$

Check nozzle to pad and shell (PG-37.3):

$$W = (A - A_1 - A_{42} - A_5)S_v \\ = (3.246 - 0.147 - 0.062 - 2.748) \times 10800 = 3121 \text{ lbs.}$$

Weld strength = WL_1 in shear + t_2 in tension

$$= 0.49(\frac{1}{2})WL_1\pi(d + 2t_n + WL_1)S_{vr1}f_{r1} + 0.74(\frac{1}{2})t_2\pi(d + 2t_n)S_{vr1}f_{r1} \\ = 0.49 \times 0.5 \times .375 \times \pi \times (5.761 + (2 \times 0.432) + .375) \times 10800 \times 1 = 21,820 \text{ lbs.} \\ = 0.74 \times 0.5 \times .375 \times \pi \times (5.761 + (2 \times 0.432)) \times 10800 \times 1 = 31,188 \text{ lbs.} \\ = 20820 + 31188 = 53008 \text{ lbs.} > 3121 \text{ lbs.}$$

PG-27 CYLINDRICAL COMPONENTS UNDER INTERNAL PRESSURE (REPRODUCED FROM ASME SECTION I)

PG-27.1 General. Unless the requirements of A-317 of Appendix A are selected, the formulas under this paragraph shall be used to determine the minimum required thickness or the maximum allowable working pressure of piping, tubes, drums, shells, and headers in accordance with the appropriate dimensional categories as given in PG-27.2.1, PG-27.2.2, and PG-27.2.3 for temperatures not exceeding those given for the various materials listed in Tables 1A and 1B of Section II, Part D.

The calculated and ordered thickness of material must include the requirements of PG-16.2, PG-16.3, and PG-16.4. Stress calculations must include the loadings as defined in PG-22 unless the formula is noted otherwise.

When required by the provisions of this Code, allowance must be provided in material thickness for threading and minimum structural stability (see PWT-9.2 and PG-27.4, Notes 3 and 5).

If local thin areas are present in cylindrical shells, the required thickness may be less than the thickness determined in PG-27 provided the requirements of Mandatory Appendix IV are met.

PG-27.2 Formulas for Calculation

PG-27.2.1 Tubing — Up to and Including 5 in. (125 mm) Outside Diameter

For bare tubes or bimetallic tubes when the strength of the clad is not included,¹ use the following equations:

$$t = \frac{PD}{2S_w + P} + 0.005D + e$$

$$P = S_w \left[\frac{2t - 0.01D - 2e}{D - (t - 0.005D - e)} \right]$$

See PG-27.4.2, PG-27.4.4, PG-27.4.8, and 27.4.10.

For bimetallic tubes when the strength of the clad is included,¹ use the following equations:

$$tb + tc' = \frac{PD}{2S_b + P} + 0.005D + e$$

$$tc' = tc \left[\frac{S_c}{S_b} \right]$$

$$t = tb + tc$$

$$P = S_b \left[\frac{2(tb + tc') - 0.01D - 2e}{D - [(tb + tc') - 0.005D - e]} \right]$$

See PG-27.4.4, PG-27.4.8, PG-27.4.10, and PG-27.4.11.

PG-27.2.1.2 The wall thickness of the ends of tubes strength-welded to headers or drums need not to be made greater than the run of the tube as determined by these formulas.

PG-27.2.1.3 The wall thickness of the ends of tubes permitted to be attached by threading under the limitations of PWT-9.2 shall not less than t as determined by this formula, plus $0.8/n$ ($20/n$), where n equals the number of threads per inch (per mm).

¹ Generalized wastage and localized corrosion, including stress corrosion cracking, have been observed in the clad of bimetallic tubes in some applications, such as chemical recovery boilers. In such applications, the choice of whether or not to include the clad strength may critically affect service performance, dependent on the environmental susceptibility of the clad.

PG-27.2.1.4 A tube in which a fusible plug is to be installed shall be not less than 0.22 in. (5.6 mm) in thickness at the plug in order to secure four full threads for the plug (see also A-20).

PG-27.2.1.5 Bimetallic tubes for which the strength of the clad is not included and meeting the requirements of PG-9.4 shall use an outside diameter, D , in the appropriate equation in PG-27.2.1 no less than the calculated outside diameter of the core material. The outside diameter of the core material shall be determined by subtracting twice the minimum thickness of the cladding from the outside diameter of the bimetallic tube, including the maximum plus tolerance of the core tube. The minimum required thickness, t , shall apply only to the core material.

Tubes for which the strength of the clad is included and meeting the requirements of PG-9.4 shall use an outside diameter, D , in the appropriate equation in PG-27.2.1 equal to the outside diameter of the bimetallic tube, including the maximum plus tolerance for both the core tube diameter and clad thickness.

PG-27.2.2 Piping, Drums, Shells, and Headers. (based on strength of weakest course)

$$t = \frac{PD}{2SE + 2yP} + C \quad \text{or} \quad \frac{PR}{SE - (1 - y)P} + C$$

$$P = \frac{2SE(t - C)}{D - 2y(t - C)} \quad \text{or} \quad \frac{SE(t - C)}{R + (1 - y)(t - C)}$$

See PG-27.4.1, PG-27.4.3, and PG-27.4.5 through PG-27.4.9.

PG-27.2.3 Thickness Greater Than One-Half the Inside Radius of the Component. The maximum allowable working pressure for parts of boilers of cylindrical cross section, designed for temperatures up to that of saturated steam of critical pressure [705.4°F (374.1°C)], shall be determined by the formulas in A-125.

PG-27.3 Symbols. Symbols used in the preceding formulas are defined as follows:

- C = minimum allowance for threading and structural stability (see PG-27.4.3)
- D = outside diameter of cylinder
- E = efficiency (see PG-27.4.1)
- e = thickness factor for expanded tube ends (see PG-27.4.4)
- P = maximum allowable working pressure (see PG-21)
- R = inside radius of cylinder
- S = maximum allowable stress value at the design temperature of the metal, as listed in the tables specified in PG-23 (see PG-27.4.2)
- S_b = maximum allowable stress value at the design temperature of the metal, as listed in the tables specified in PG-23, for a bimetallic tube in which the clad strength is to be included (see PG-27.4.11)
- S_c = maximum allowable stress value at the design temperature of the clad metal, as listed in the Section II, Part D, Tables 1A or 1B, for a bimetallic tube in which the clad strength is to be included (see PG-27.4.11)
- t = minimum required thickness (see PG-27.4.7)
- t_b = minimum required thickness of the base metal for a bimetallic tube in which the clad strength is to be included (see PG-27.4.11)
- t_c = minimum required thickness of the clad for a bimetallic tube in which the clad strength is to be included (see PG-27.4.11)
- t_c' = minimum effective clad thickness for strength purposes for a bimetallic tube in which the clad strength is to be included (see PG-27.4.11)
- w = weld joint strength reduction factor per PG-26
- y = temperature coefficient (see PG-27.4.6)

PG-27.4 Notes. Notes referenced in the preceding formulas are as follows:

PG-27.4.1 Note 1

- $E = 1.0$ for seamless cylinders without openings spaced to form ligaments
- = the ligament efficiency per PG-52 or PG-53 for seamless cylinders with ligaments
- = w , the weld joint strength reduction factor per PG-26, for longitudinally welded cylinders without ligaments

For longitudinally welded cylinders with ligaments located such that no part of the longitudinal weld seam is penetrated by the openings forming the ligament, E shall be taken as the lesser of w or the ligament efficiency from PG-52 or PG-53. If any part of the longitudinal seam weld is penetrated by the openings that form ligaments, E shall be taken as the products of w times the ligament efficiency.

PG-27.4.2 Note 2. The temperature of the metal to be used in selecting the S value for tubes shall not be less than the maximum expected mean wall temperature, i.e., the sum of the outside and inside tube surface temperatures divided by 2. For tubes that do not absorb heat, the metal temperature may be taken as the temperature of the fluid within the tube but not less than the saturation temperature.

PG-27.4.3 Note 3. Any additive thickness represented by the general term C may be considered to be applied on the outside, the inside, or both. It is the responsibility of the designer using these formulas to make the appropriate selection of diameter or radius to correspond to the intended location and magnitude of this added thickness. The pressure- or stress-related term in the formula should be evaluated using the diameter (or radius) and the remaining thickness which would exist if the “additive” thickness had not been applied or is imagined to have been entirely removed.

The values of C below do not include any allowance for corrosion and/or erosion, and additional thickness should be provided where they are expected. Likewise, this allowance for threading and minimum structural stability is not intended to provide for conditions of misapplied external loads or for mechanical abuse.

Threaded Pipe ^a	Value of C^b in. (mm)
$D \leq \frac{3}{4}$ in. (19 mm) nominal	0.065 (1.65)
$D > \frac{3}{4}$ in. (19 mm) nominal	Depth of thread h^c

(a) Steel or nonferrous pipe lighter than Schedule 40 of ASME B36.10M, Welded and Seamless Wrought Steel Pipe, shall not be threaded.

(b) The values of C stipulated above are such that the actual stress due to internal pressure in the wall of the pipe is no greater than the values of S given in Table 1A of Section II, Part D, as applicable in the formulas.

(c) The depth thread h in in. (mm) may be determined from the formula $h = 0.8/n$ ($h = 20/n$), where n is the number of threads per inch (25 mm) or from the following:

n	h
8	0.100 (2.5)
11½	0.0696 (1.77)

PG-27.4.4 Note 4

- $e = 0.04$ (1.0) over a length at least equal to the length of the seat plus 1 in. (25 mm) for tubes expanded into tube seats, except
- = 0 for tubes expanded into tube seats provided the thickness of the tube ends over a length of the seat plus 1 in. (25 mm) is not less than the following:
 - (a) 0.095 in. (2.41 mm) for tubes 1¼ in. (32 mm) O.D. and smaller
 - (b) 0.105 in. (2.67 mm) for tubes above 1¼ in. (32 mm) O.D. and up to 2 in. (50 mm) O.D., incl.
 - (c) 0.120 in. (3.05 mm) for tubes above 2 in. (50 mm) O.D. and up to 3 in. (75 mm) O.D., incl.
 - (d) 0.135 in. (3.43 mm) for tubes above 3 in. (76 mm) O.D. and up to 4 in. (100 mm) O.D., incl.
 - (e) 0.150 in. (3.81 mm) for tubes above 4 in. (100 mm) O.D. and up to 5 in. (125 mm) O.D., incl.
- = 0 for tube strength-welded to headers and drums

PG-27.4.5 Note 5. While the thickness given by the formula is theoretically ample to care of both bursting pressure and material removed in threading, when steel pipe is threaded and used for steam pressures of 250 psi (1.7 MPa) and over, it shall be seamless and of a weight at least equal to Schedule 80 in order to furnish added mechanical strength.

PG-27.4.6 Note 6

y = a coefficient having values as follows:

	Temperature, °F (°C)							
	900 (480) and below	950 (510)	1,000 (540)	1,050 (565)	1,100 (595)	1,150 (620)	1,200 (650)	1,250 (675) and above
Ferritic	0.4	0.5	0.7	0.7	0.7	0.7	0.7	0.7
Austenitic	0.4	0.4	0.4	0.4	0.5	0.7	0.7	0.7
Alloy 800, 801	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.7
800H, 800HT	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.7
825	0.4	0.4	0.4	...	...	...	...	...
230 Alloy	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.7
N06022	0.4	0.4	0.4	0.4	0.5	0.7	0.7	0.7
N06045	0.4	0.4	0.4	0.4	0.5	0.7	0.7	0.7
N06600	0.4	0.4	0.4	0.4	0.5	0.7	0.7	...
N06601	0.4	0.4	0.4	0.4	0.5	0.7	0.7	...
N06625	0.4	0.4	0.4	0.4	0.4	...	...	...
N06690	0.4	0.4	0.4	0.4	0.5	0.7	0.7	...
Alloy 617	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.7
S31803	0.4	...	...	...	...	...	...	...

Values of y between temperatures listed may be determined by interpolation. For nonferrous materials not listed, $y = 0.4$.

PG-27.4.7 Note 7. If pipe is ordered by its nominal wall thickness, as is customary in trade practice, the manufacturing tolerance on wall thickness must be taken into account. After the minimum pipe wall thickness t is determined by the formula, this minimum thickness shall be increased by an amount sufficient to provide the manufacturing tolerance allowed in the applicable pipe specification. The next heavier commercial wall thickness may then be selected from Standard thickness schedules as contained in ASME B36.10M. The manufacturing tolerances are given in the several pipe specifications listed in PG-9.

PG-27.4.8 Note 8. When computing the allowable pressure for a pipe of a definite minimum wall thickness, the value obtained by the formulas may be rounded up to the next higher unit of 10 psi (0.1 MPa).

PG-27.4.9 Note 9. Inside backing strips, when used at longitudinal welded joints, shall be removed and the weld surface prepared for volumetric examinations as required. Inside backing rings may remain at circumferential welded seams of cylinders provided such construction complies with requirements of PW-41.

PG-27.4.10 Note 10. The maximum allowable working pressure P need not include the hydrostatic head loading. PG-22, when used in this equation.

PG-27.4.11 Note 11. This note has additional requirements for bimetallic tubes for which the strength of the clad is included. For additional fabrication requirements, see PW-44. For such bimetallic tubes, the thermal conductivity of the base metal shall be equal to or greater than the thermal conductivity of the clad material. The cladding process shall achieve a metallurgical bond between the clad and the base metal (core tube).

The temperature of the metal to be used in selecting the S_b value for core tubes shall not be less than the maximum expected mean wall temperature calculated using the base metal thermal properties for a tube with the same outside diameter and total wall thickness as the clad tube, i.e., the sum of the outside and inside tube surface temperature of an equivalent core tube, divided by 2.

The temperature of the metal to be used in selecting the Sc value for the clad shall not be less than the maximum expected mean wall temperature of the clad, i.e., the sum of the outside surface temperature and the base metal-clad interface temperature, divided by 2.

The value of Sc shall be taken as that for an annealed wrought material with nominally equivalent strength and composition as the clad. Values applicable to either Section I or Section VIII, Division 1 may be used. If two stress values are listed for a material, the higher value may be used.

The sizing equation is subject to the following constraints:

$$tb \geq tc \text{ (excludes clads thicker than core tube)}$$

$$t < \frac{D}{4} \text{ (exclude thick-walled tubes)}$$

$$\text{If } \left(\frac{Sc}{Sb} \right) \geq 1, \text{ the ratio is set to 1 in the calculation}$$

$$\text{If } \left(\frac{Sc}{Sb} \right) < 1, \text{ the actual ratio is used in the calculation}$$

PG-29 DISHED HEADS (REPRODUCED FROM SECTION I)

PG-29.1 The thickness of a blank unstayed dished head with the pressure on the concave side, when it is a segment of a sphere, shall be calculated by the following equation:

$$t = 5PL / 4.8Sw$$

where

L = radius to which the head is dished, measured on the concave side of the head

P = maximum allowable working pressure (hydrostatic head loading need not be included)

S = maximum allowable working stress using values given in Table 1A of Section II, Part D

t = minimum thickness of head

w = weld joint strength reduction factor per PG-26

PG-29.1.1 If local thin areas are present in the spherical portion of the dished head, the required thickness may be less than the thickness determined in PG-29.1 provided the requirements of Mandatory Appendix IV are met.

PG-29.2 The radius to which a head is dished shall be not greater than the outside diameter of flanged portion of the head. Where two radii are used the longer shall be taken as the value of L in the equation.

PG-29.3 When a head dished to a segment of a sphere has a flanged-in manhole or access opening that exceeds 6 in. (150 mm) in any dimension, the thickness shall be increased by not less than 15% of the required thickness for a blank head computed by the above formula, but in no case less than 1/8 in. (3 mm) additional thickness over a blank head. Where such a dished head has a flanged opening supported by an attached flue, an increase in thickness over that for a blank head is not required. If more than a manhole is inserted in a head, the thickness of which is calculated by this rule, the minimum distance between the openings shall be not less than one-fourth of the outside diameter of the head.

PG-29.4 Except as otherwise provided for in PG-29.3, PG-29.7, and PG-29.12, all openings which require reinforcement, placed in a head dished to a segment of a sphere, or in an ellipsoidal head, or in a

full-hemispherical head, including all types of manholes except those of the integral flanged-in type, shall be reinforced in accordance with the rules in PG-33.

When so reinforced, the thickness of such a head may be the same as for a blank unstayed head.

PG-29.5 When the radius L to which the head is dished is less than 80% of the outside diameter of the head, the thickness of the head with a flange-in manhole opening shall be at least that found by making L equal to 80% of the outside diameter of the head and with the added thickness for the manhole. The thickness shall be the minimum thickness of a head with a flanged-in manhole opening for any form of head and the maximum allowable working stress shall not exceed the values given in Table 1A of Section II, Part D.

PG-29.6 No head, except a full-hemispherical head, shall be of a lesser thickness than that required for a seamless shell of the same diameter.

PG-29.7 A blank head of a semiellipsoidal form in which half the minor axis or the depth of the head is at least equal to one-quarter of the inside diameter of the head shall be made at least as thick as the required thickness of a seamless shell of the same diameter as provided in PG-27.2.2. If a flanged-in manhole that meets the Code requirements is placed in an ellipsoidal head, the thickness of the head shall be the same as for a head dished to a segment of a sphere (see PG-29.1 and PG-29.5) with a dish radius equal to eight-tenths the outside diameter of the head and with the added thickness for the manhole as specified in PG-29.3.

PG-29.8 When heads are made to an approximate ellipsoidal shape, the inner surface of such heads must lie outside and not inside of a true ellipse drawn with the major axis equal to the inside diameter of the head and one-half the minor axis equal to the depth of the head. The maximum variation from this true ellipse shall not exceed 0.0125 times the inside diameter of the head.

PG-29.9 Unstayed dished heads with the pressure on the convex side shall have a maximum allowable working pressure equal to 60% of that for heads of the same dimensions with the pressure on the concave side.

Head thickness obtained by using the formulas in PG-29.11 for hemispherical heads and PG-29.7 for a blank semiellipsoidal heads do not apply to heads with pressure on the convex side.

PG-29.11 The thickness of a blank unstayed full-hemispherical head with the pressure on the concave side shall be calculated by the following equation:

$$t = \frac{PL}{2Sw - 0.2P}$$

where

L = radius to which the head was formed, measured on the concave side of the head

P = maximum allowable working pressure

S = maximum allowable working stress, using values given in Table 1A of Section II, Part D

t = minimum thickness of head

w = weld joint strength reduction factor per PG-26

The above equation shall not be used when the required thickness of the head given by this formula exceeds 35.6% of the inside radius, and instead, the following equation shall be used:

$$t = L(Y^{1/3} - 1)$$

where

$$Y = \frac{2(Sw + P)}{2Sw - P}$$

Joints in full-hemispherical heads including the joint to the shell shall be governed by and meet all the requirements for longitudinal joints in a cylindrical shells, except that in a butt welded joint attaching a head to a shell the middle lines of the plate thickness need not be in alignment.

If local thin areas are present in the full-hemispherical head, the required thickness may be less than the thickness determined above provided the requirements of Mandatory Appendix IV are met.

PG-29.12 If a flanged-in manhole that meets the Code requirements is placed in a full-hemispherical head, the thickness of the head shall be the same for a head dished to a segment of a sphere (see PG-29.1 and PG-29.5), with a dish radius equal to eight-tenths the outside diameter of the head and with the added thickness for the manhole as specified in PG-29.3.

PG-29.13 The corner radius of an unstayed dished head measured on the concave side of the head shall be not less than three times the thickness of the material in the head; but in no case less than 6% of the outside diameter of the head. In no case shall the thinning-down due to the process of forming, of the knuckle portion of any dished head consisting of a segment of a sphere encircled by a part of a torus constituting the knuckle portion (torispherical), exceed 10% of the thickness required by the formula in PG-29.1. Other types of heads shall have a thickness after forming of not less than that required by the applicable equation.

ASME B16.34-2009
TABLE 1 MATERIAL SPECIFICATION LIST
(REPRODUCED FROM ASME B16.34)

GROUP 1 MATERIALS

Material		Forgings		Castings		Plates		Bars		Tubular	
Group No.	Nominal Designation	Spec. No.	Grade	Spec. No.	Grade	Spec. No.	Grade	Spec. No.	Grade	Spec. No.	Grade
1.1	C-Si C-Mn-Si	A 105	LF2	A 216	WCB	A 515	70	A 105 A 350 A 696	LF2 C	A 672 A 672	C 70 B 70
		A 350				A 516 A 537	70 Cl. 1				
1.2	3½Ni C-Mn-Si-V	A 350	LF3 LF6 Cl. 1	A 352 A 352 A 216 A 352	LC2 LC3 WCC LCC	A 350	LF3 LF6 Cl. 1	A 350 A 350	LF3 LF6 Cl. 1	A 106	C
		A 350				A 203 A 203 A 203	B E				
1.3	C C-Si 2½Ni 3½Ni C-Mn-Si C-½Mo	A 350	LF6 Cl. 2	A 352	LCB	A 515 A 203 A 203 A 516	65 A D 65	A 675	70	A 672 A 672	B 65 C 65
						A 217 A 352	WC1 LC1				
1.4	C C-Si C-Mn-Si		LF1	A 350		A 515 A 516	60 60	A 675 A 675 A 350 A 696	60 65 LF1 B	A 106 A 672 A 672	B B 60 C 60

1.5	C-½Mo	A 182	F1			A 204 A 204	A B	A 182	F1	A 691	CM-70
1.6	½Cr-½Mo					A 387 A 387	2 Cl. 1 2 Cl. 2			A 691	½CR
1.7	C-½Mo ½Cr-½Mo Ni-½Cr-½Mo ¾Ni-Mo-¾Cr	A 182	F2	A 217 A 217	WC4 WC5			A 182	F2	A 691	CM-75
1.8	1Cr-½Mo 1¼Cr-½Mo-Si 2¼Cr-1Mo					A 387 A 387 A 387	12 Cl. 2 11 Cl. 1 22 Cl. 1			A 691 A 691 A 335 A 469	1¼CR 2¼CR P22 FP22
1.9	1¼Cr-½Mo-Si 1¼Cr-½Mo	A 182	F11 Cl. 2	A 217	WC6	A 387	11 Cl. 2	A 182 A 739	F11 Cl. 2 B11		
1.10	2¼Cr-1Mo	A 182	F22 Cl. 3	A 217	WC9	A 387	22 Cl. 2	A 182 A 739	F22 Cl. 3 B22		
1.11	3Cr-1Mo Mn-½Mo Mn-½Mo-½Ni Mn-½Mo-¾Ni C-Mn-Si C-½Mo	A 182	F21			A 387 A 302 A 302 A 302 A 537 A 204	21 Cl. 2 A & B C D CL2 C	A 182	F21		
1.12	5Cr-½Mo 5Cr-½Mo-Si					A 387 A 387	5 Cl. 1 5 Cl. 2			A 691 A 335 A 369 A 335	5CR P5 FP5 P5b

ASME B36.10M-2004 **ELDED AND SEAMLESS WROUGHT STEEL PIPE**

TABLE 2 DIMENSIONS AND WEIGHTS OF WELDED AND SEAMLESS STEEL PIPE
(EXCERPT – REPRODUCED FROM ASME B36.10M)

CUSTOMARY UNITS					SI UNITS				
NPS [NOTE (1)]	OUTSIDE DIAMETER, IN.	WELL THICKNESS, IN.	PLAIN END WEIGHT, LB/FT	IDENTIFICATION [STANDARD (STD), EXTRA-STRONG (XS), OR DOUBLE EXTRA STRONG (XXS)]	SCHEDULE NO.	DN [NOTE (2)]	OUTSIDE DIAMETER, MM	WALL THICKNESS, MM	PLAIN END MASS, KG/M
6	6.625	0.312	21.06	...	...	150	168.3	7.92	31.33
6	6.625	0.344	23.10	...	...	150	168.3	8.74	34.39
6	6.625	0.375	25.05	...	...	150	168.3	9.53	37.31
6	6.625	0.432	28.60	XS	80	150	168.3	10.97	42.56
6	6.625	0.500	32.74	...	...	150	168.3	12.70	48.73
6	6.625	0.562	36.43	...	120	150	168.3	14.27	54.21
6	6.625	0.625	40.09	...	...	150	168.3	15.88	59.69
6	6.625	0.719	45.39	...	160	150	168.3	18.26	67.57
6	6.625	0.750	47.10	...	...	150	168.3	19.05	70.12
6	6.625	0.864	53.21	XXS	...	150	168.3	21.95	79.22
6	6.625	0.875	53.78	...	...	150	168.3	22.23	80.08
8	8.625	0.109	9.92	...	5	200	219.1	2.77	14.78
8	8.625	0.125	11.36	...	...	200	219.1	3.18	16.93
8	8.625	0.148	13.41	...	10	200	219.1	3.76	19.97
8	8.625	0.156	14.12	...	...	200	219.1	3.96	21.01
8	8.625	0.188	16.96	...	...	200	219.1	4.78	25.26
8	8.625	0.203	18.28	...	...	200	219.1	5.16	27.22
8	8.625	0.219	19.68	...	...	200	219.1	5.56	29.28
8	8.625	0.250	22.38	...	20	200	219.1	6.35	33.32
8	8.625	0.277	24.72	...	...	200	219.1	7.04	36.82
8	8.625	0.312	27.73	...	...	200	219.1	7.92	41.25
8	8.625	0.322	28.58	STD	40	200	219.1	8.18	42.55
8	8.625	0.344	30.45	...	...	200	219.1	8.74	45.34
8	8.625	0.375	33.07	...	...	200	219.1	9.53	49.25
8	8.625	0.406	35.67	...	60	200	219.1	10.31	53.09
8	8.625	0.438	38.33	...	...	200	219.1	11.13	57.08
8	8.625	0.500	43.43	XS	80	200	219.1	12.70	64.64

8	8.625	0.562	48.44	...	...	200	219.1	14.27	72.08
8	8.625	0.594	51.00	...	...	200	219.1	15.09	75.92
8	8.625	0.625	53.45	...	...	200	219.1	15.88	79.59
8	8.625	0.719	60.77	...	...	200	219.1	18.26	90.44
8	8.625	0.750	63.14	...	...	200	219.1	19.05	93.98
8	8.625	0.812	67.82	...	...	200	219.1	20.62	100.93
8	8.625	0.875	72.49	XXS	...	200	219.1	22.23	107.93
8	8.625	0.906	74.76	...	...	200	219.1	23.01	111.27
8	8.625	1.000	81.51	...	...	200	219.1	25.40	121.33
10	10.750	0.134	15.21	...	...	250	273.0	3.40	22.61
10	10.750	0.156	17.67	...	...	250	273.0	3.96	26.27
10	10.750	0.165	18.67	...	...	250	273.0	4.19	27.78
10	10.750	0.188	21.23	...	...	250	273.0	4.78	31.62
10	10.750	0.203	22.89	...	...	250	273.0	5.16	34.08
10	10.750	0.219	24.65	...	...	250	273.0	5.56	36.67
10	10.750	0.250	28.06	...	...	250	273.0	6.35	41.76
10	10.750	0.279	31.23	...	...	250	273.0	7.09	46.49
10	10.750	0.307	34.27	...	...	250	273.0	7.80	51.01
10	10.750	0.344	38.27	STD	...	250	273.0	8.74	56.96
10	10.750	0.365	40.52	...	...	250	273.0	9.27	60.29
10	10.750	0.438	48.28	...	...	250	273.0	11.13	71.88
10	10.750	0.500	54.79	XS	...	250	273.0	12.70	81.53
10	10.750	0.562	61.21	...	...	250	273.0	14.27	91.05
10	10.750	0.594	64.49	...	...	250	273.0	15.09	95.98
10	10.750	0.625	67.65	...	...	250	273.0	15.88	100.69
10	10.750	0.719	77.10	...	...	250	273.0	18.26	114.71
10	10.750	0.812	86.26	...	...	250	273.0	20.62	128.34
10	10.750	0.844	89.38	...	...	250	273.0	21.44	133.01
10	10.750	0.875	92.37	...	...	250	273.0	22.23	137.48
10	10.750	0.938	98.39	...	...	250	273.0	23.83	146.43
10	10.750	1.000	104.23	XXS	...	250	273.0	25.40	155.10
10	10.750	1.125	115.75	...	...	250	273.0	28.58	172.27
10	10.750	1.250	126.94	...	...	250	273.0	31.75	188.90
12	12.750	0.156	21.00	...	...	300	323.8	3.96	31.24
12	12.750	0.172	23.13	...	...	300	323.8	4.37	34.43
12	12.750	0.180	24.19	...	...	300	323.8	4.57	35.98
12	12.750	0.188	25.25	...	...	300	323.8	4.78	37.61

SME B36.10M-2004

ELDED AND SEAMLESS WROUGHT STEEL PIPE

TABLE 2 DIMENSIONS AND WEIGHTS OF WELDED AND SEAMLESS STEEL PIPE
(EXCERPT – REPRODUCED FROM ASME B36.10M)

CUSTOMARY UNITS					SI UNITS				
NPS [NOTE (1)]	OUTSIDE DIAMETER, IN.	WELL THICKNESS, IN.	PLAIN END WEIGHT, LB/FT	IDENTIFICATION [STANDARD (STD), EXTRA-STRONG (XS), OR DOUBLE EXTRA STRONG (XXS)]	SCHEDULE NO.	DN [NOTE (2)]	OUTSIDE DIAMETER, MM	WALL THICKNESS, MM	PLAIN END MASS, KG/M
12	12.750	0.203	27.23	...	...	300	323.8	5.16	40.55
12	12.750	0.219	29.34	...	...	300	323.8	5.56	43.64
12	12.750	0.250	33.41	...	20	300	323.8	6.35	49.71
12	12.750	0.281	37.46	...	...	300	323.8	7.14	55.76
12	12.750	0.312	41.48	...	...	300	323.8	7.92	61.70
12	12.750	0.330	43.81	...	30	300	323.8	8.38	65.19
12	12.750	0.344	45.62	...	...	300	323.8	8.74	67.91
12	12.750	0.375	49.61	STD	...	300	323.8	9.53	73.86
12	12.750	0.406	53.57	...	40	300	323.8	10.31	79.71
12	12.750	0.438	57.65	...	...	300	323.8	11.13	85.82
12	12.750	0.500	65.48	XS	...	300	323.8	12.70	97.44
12	12.750	0.562	73.22	...	60	300	323.8	14.27	108.93

12	12.750	0.625	81.01	...	...	...	300	323.8	15.88	120.59
12	12.750	0.688	88.71	...	...	80	300	323.8	17.48	132.05
12	12.750	0.750	96.21	...	...	...	300	323.8	19.05	143.17
12	12.750	0.812	103.63	...	...	...	300	323.8	20.62	154.17
12	12.750	0.844	107.42	...	...	100	300	323.8	21.44	159.87
12	12.750	0.875	111.08	...	...	...	300	323.8	22.23	165.33
12	12.750	0.938	118.44	...	...	...	300	323.8	23.83	176.29
12	12.750	1.000	125.61	XXS	...	120	300	323.8	25.40	186.92
12	12.750	1.062	132.69	...	...	...	300	323.8	26.97	197.43
12	12.750	1.125	139.81	...	...	140	300	323.8	28.58	208.08
12	12.750	1.250	153.67	...	...	...	300	323.8	31.75	228.68
12	12.750	1.312	160.42	...	...	160	300	323.8	33.32	238.69
14	14.000	0.156	23.09	...	...	5	350	355.6	3.96	34.34
14	14.000	0.188	27.76	...	...	...	350	355.6	4.78	41.36
14	14.000	0.203	29.94	...	...	...	350	355.6	5.16	44.59
14	14.000	0.210	30.96	...	...	...	350	355.6	5.33	46.04
14	14.000	0.219	32.26	...	...	...	350	355.6	5.56	48.00
14	14.000	0.250	36.75	...	...	10	350	355.6	6.35	54.69
14	14.000	0.281	41.21	...	...	...	350	355.6	7.14	61.36
14	14.000	0.312	45.65	...	...	20	350	355.6	7.92	67.91

ASME B16.34-2009
TABLE 2.1.1 RATING FOR GROUP 1.1 MATERIALS
(REPRODUCED FROM ASME B16.34)

A 105 (1) (2)	A 515 Gr. 70 (1)	A 696 Gr. C (5)	A 672 Gr. B70 (1)
A 216 GR. WCB (1)	A 516 Gr. 70 (1) (3)	A 350 Gr. LF6 Cl. 1 (4)	A 672 Gr. C70 (1)
A 350 Gr. LF2 (1)	A 537 Cl. 1 (5)	A 350 Gr. LF3 (6)	

NOTES:

- (1) Upon prolonged exposure to temperature above 425°C, the carbide phase of steel may be converted to graphite. Permissible, but not recommended for prolonged usage above 425°C.
(2) Only killed steel shall be used above 455°C.
(3) Not be used over 455°C.
(4) Not be used over 460°C.
(5) Not be used over 370°C.
(6) Not be used over 345°C.

A – Standard Class

Temperature, °C	Working Pressure by Class, bar						
	150	300	600	900	1500	2500	4500
–29 to 38	19.6	51.1	102.1	153.2	255.3	425.5	765.9
50	19.2	50.1	100.2	150.4	250.6	417.7	751.9
100	17.7	46.6	93.2	139.8	233.0	388.3	699.0
150	15.8	45.1	90.2	135.2	225.4	375.6	676.1
200	13.8	43.8	87.6	131.4	219.0	365.0	675.0
250	12.1	41.9	83.2	125.8	209.7	349.5	629.1
300	10.2	39.8	79.6	119.5	199.1	331.8	597.3
325	9.3	38.7	77.4	116.1	193.6	322.6	580.7
350	8.4	37.6	75.1	112.7	187.8	313.0	563.5
375	7.4	36.4	72.7	109.1	181.8	303.1	545.5
400	6.5	34.7	69.4	104.2	173.6	289.3	520.8
425	5.5	28.8	57.5	86.3	143.8	239.7	431.5
450	4.6	23.0	46.0	69.0	115.0	191.7	345.1
475	3.7	17.4	34.9	52.3	87.2	145.3	261.5
500	2.8	11.8	23.5	35.3	58.8	97.9	176.3
538	1.4	5.9	11.8	17.7	29.5	49.2	88.6

B – Special Class

Temperature, °C	Working Pressure by Class, bar						
	150	300	600	900	1500	2500	4500
–29 to 38	19.8	51.7	103.4	155.1	258.6	430.9	775.7
50	19.8	51.7	103.4	155.1	258.6	430.9	775.7
100	19.8	51.6	103.3	154.9	258.2	430.3	774.5
150	19.6	51.0	102.1	153.1	255.2	425.3	765.5
200	19.4	50.6	101.1	151.7	252.9	421.4	758.6
250	19.4	50.5	101.1	151.6	252.6	421.1	757.9
300	19.4	50.5	101.1	151.6	252.6	421.1	757.9
325	19.2	50.1	100.2	150.3	250.6	417.6	751.7
350	18.7	48.9	97.8	146.7	244.6	407.6	733.7
375	18.1	47.1	94.2	141.3	235.5	392.5	706.5
400	16.6	43.4	86.8	130.2	217.0	361.7	651.0
425	13.8	36.0	71.9	107.9	179.8	299.6	539.3
450	11.0	28.8	57.5	86.3	143.8	239.6	431.4
475	8.4	21.8	43.6	65.4	109.0	181.6	326.9
500	5.6	14.7	29.4	44.1	73.5	122.4	220.4
538	2.8	7.4	14.8	22.2	36.9	61.6	110.8

APPENDIX V

ILLUSTRATIONS OF VARIOUS TYPES OF BOILERS

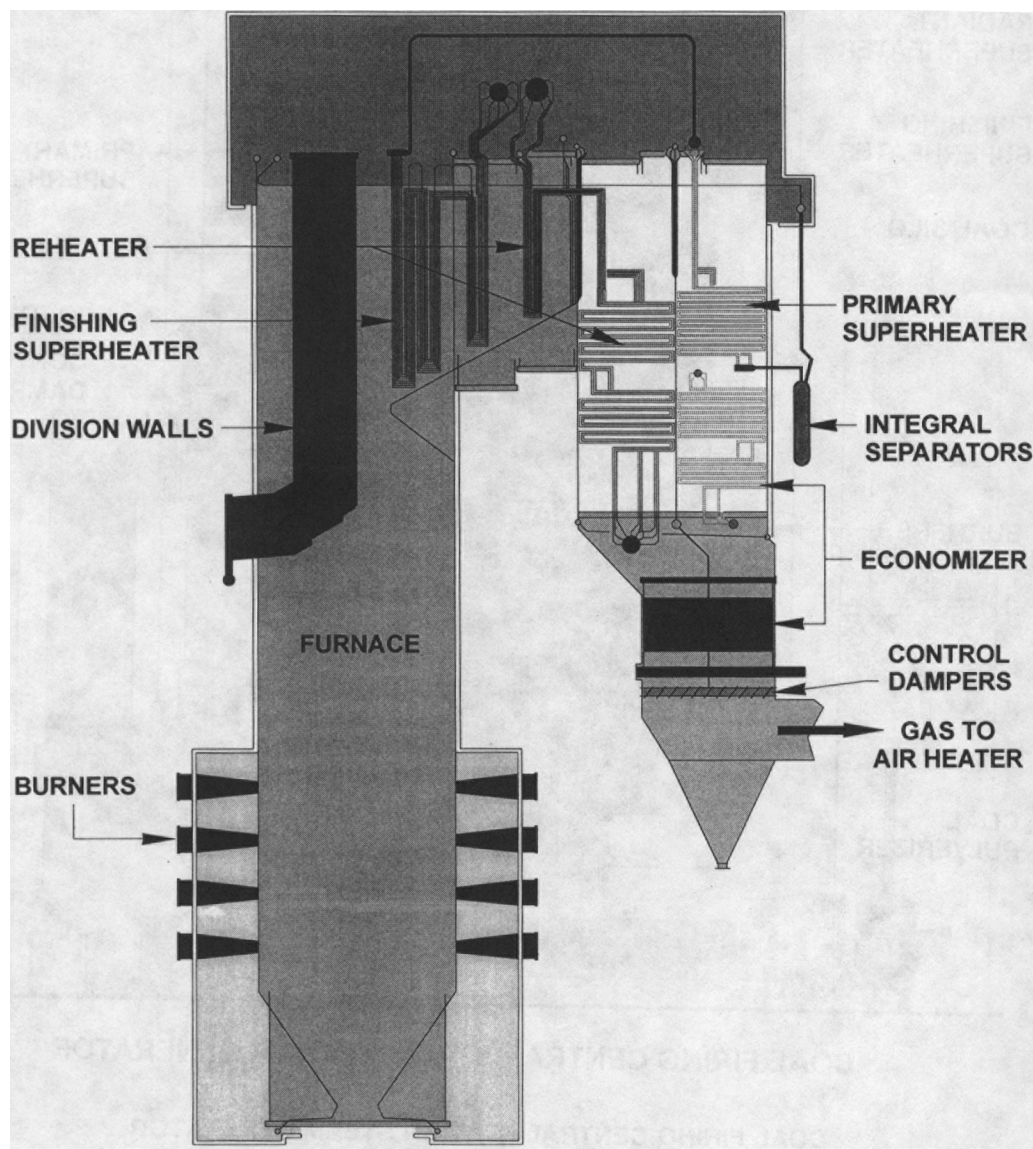


FIG. A.V.1
SUPERCritical ONCE-THROUGH COAL FIRING STEAM GENERATOR
(COURTESY OF FOSTER WHEELER ENERGY CORPORATION)

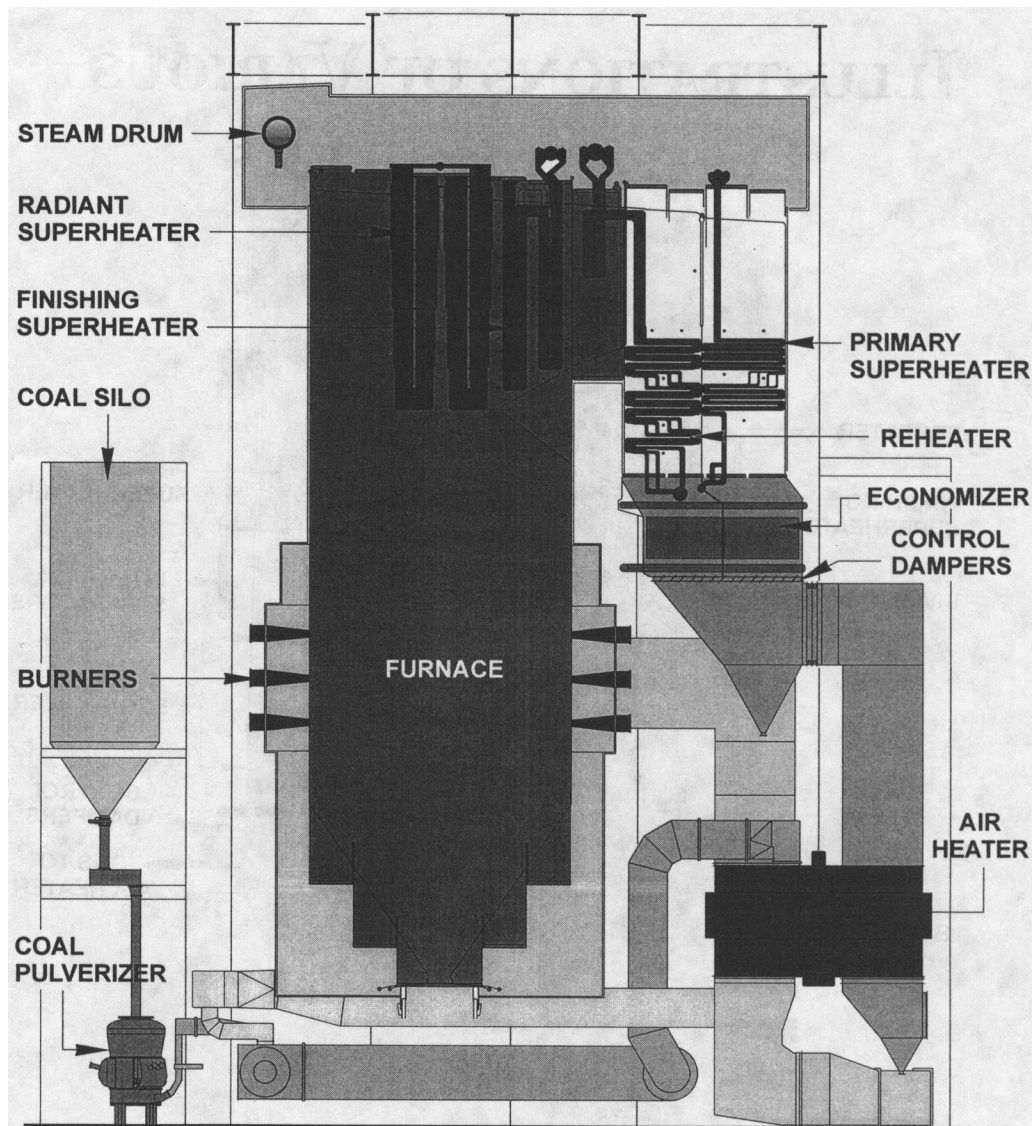


FIG. A.V.2
COAL FIRING CENTRAL STATION STEAM GENERATOR
(COURTESY OF FOSTER WHEELER ENERGY CORPORATION)

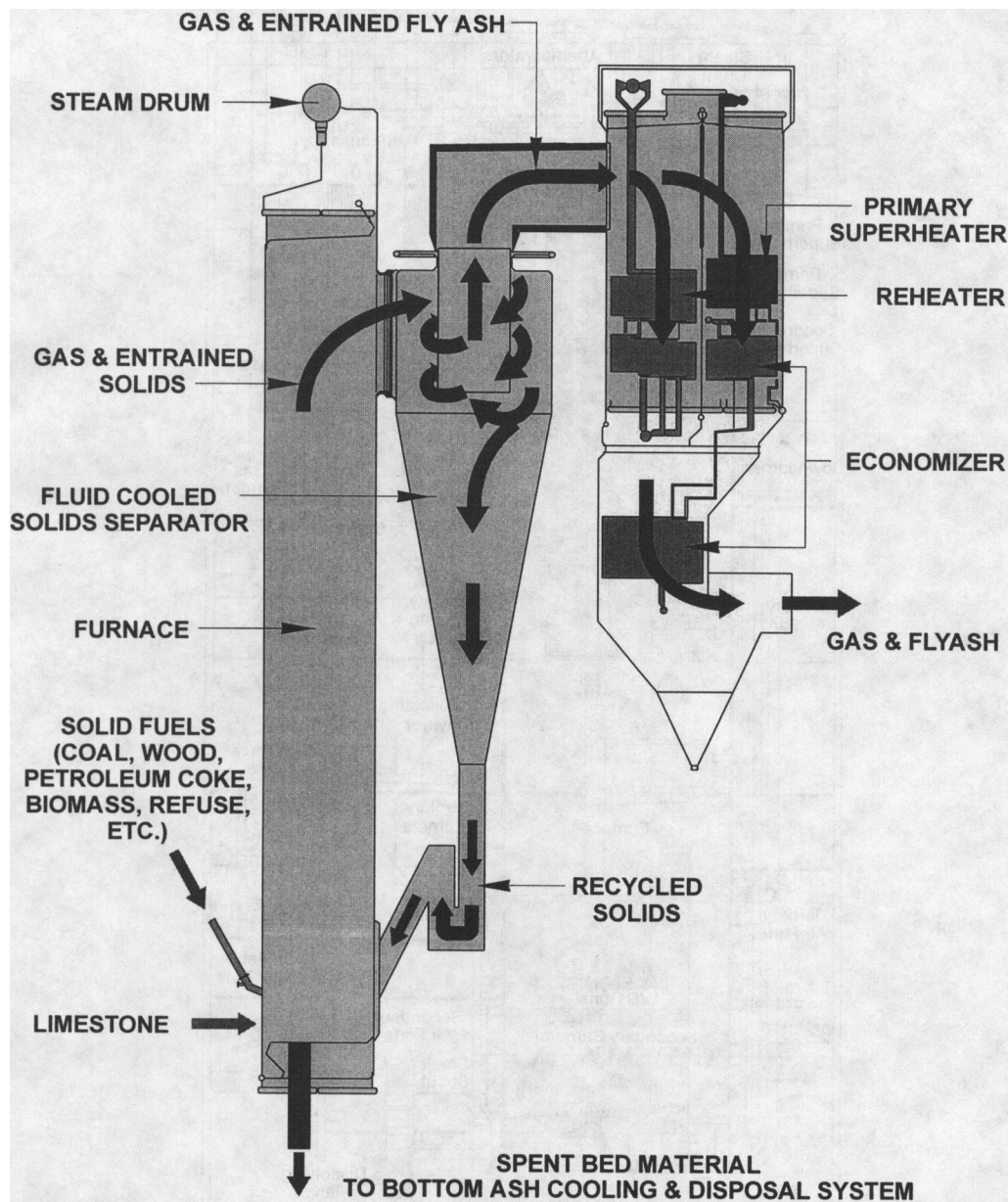


FIG. A.V.3
CIRCULATING FLUIDIZED BED BOILER
(COURTESY OF FOSTER WHEELER ENERGY CORPORATION)

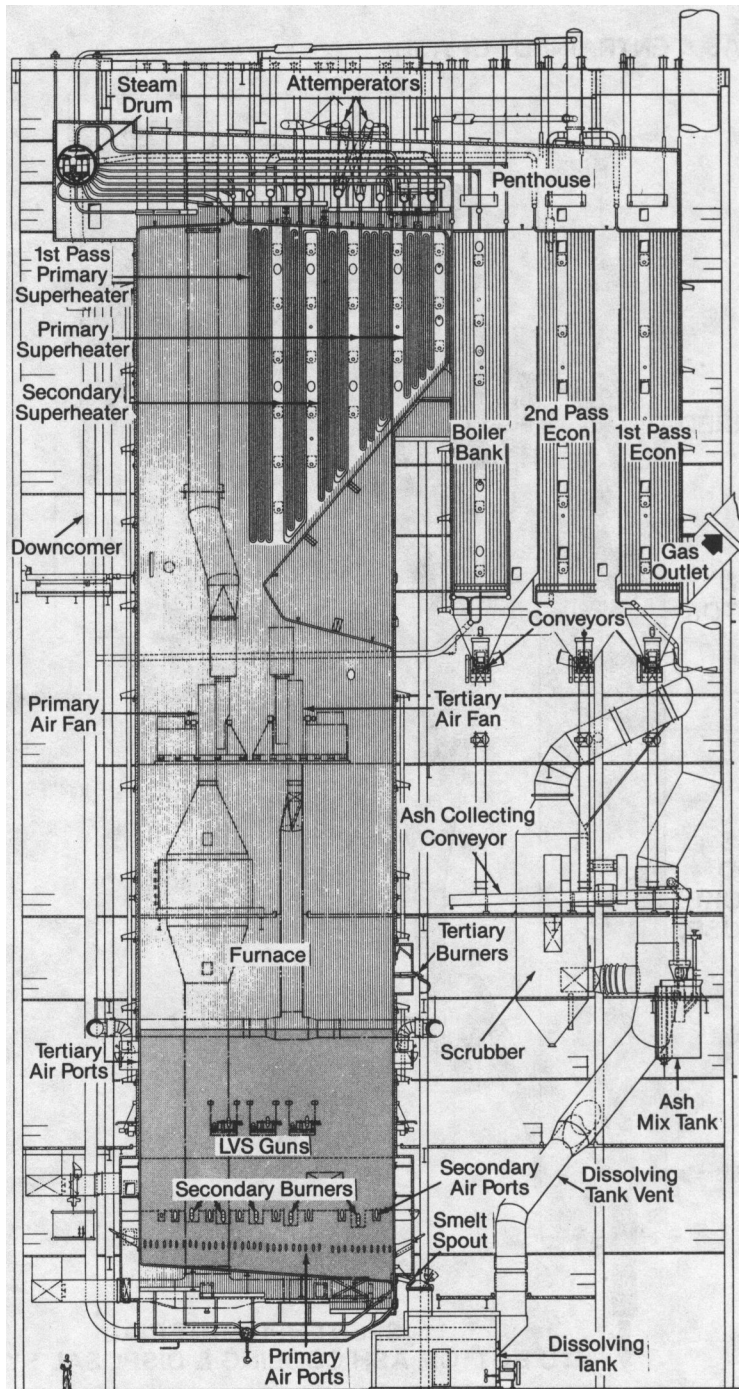


FIG. A.V.4
KRAFT PROCESS BLACK LIQUOR RECOVERY BOILER
(COURTESY OF THE BABCOCK & WILCOX COMPANY)

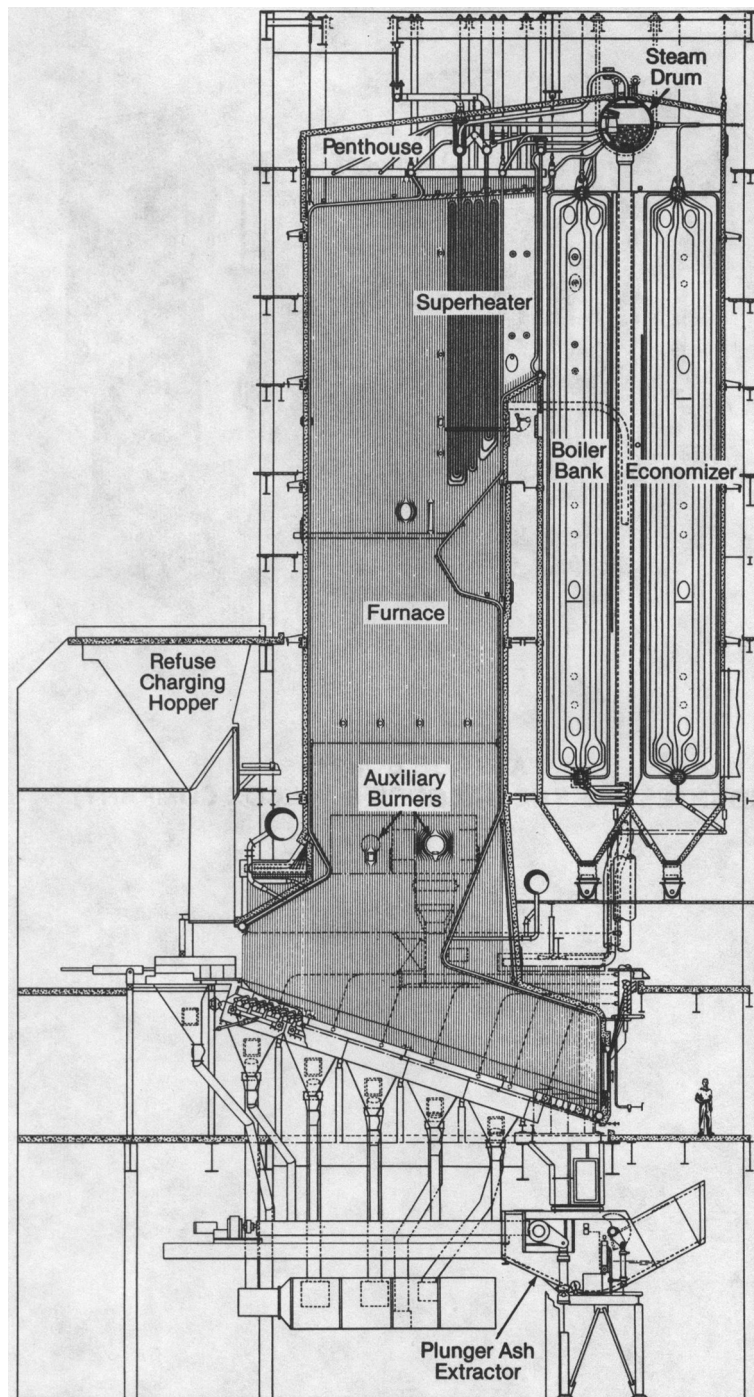


FIG. A.V.5
REFUSE FIRED BOILER
(COURTESY OF THE BABCOCK & WILCOX COMPANY)

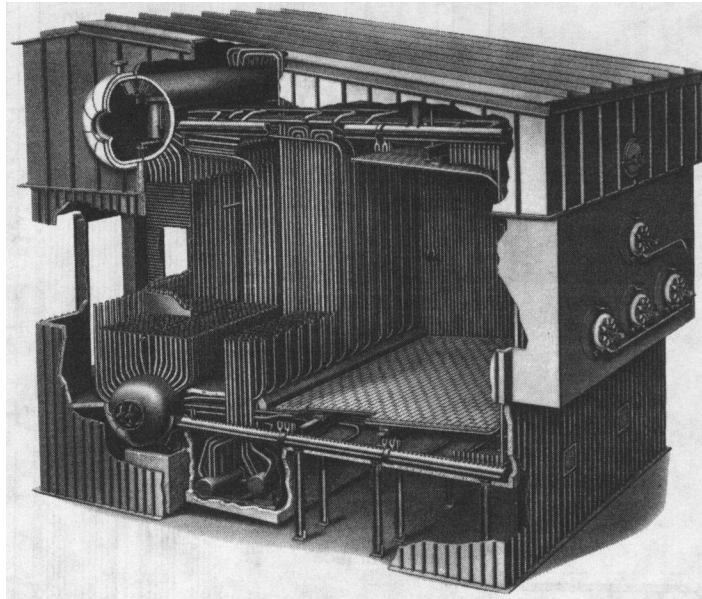


FIG. A.V.6
PACKAGE WATERTUBE BOILER
(COURTESY OF THE BABCOCK & WILCOX COMPANY)

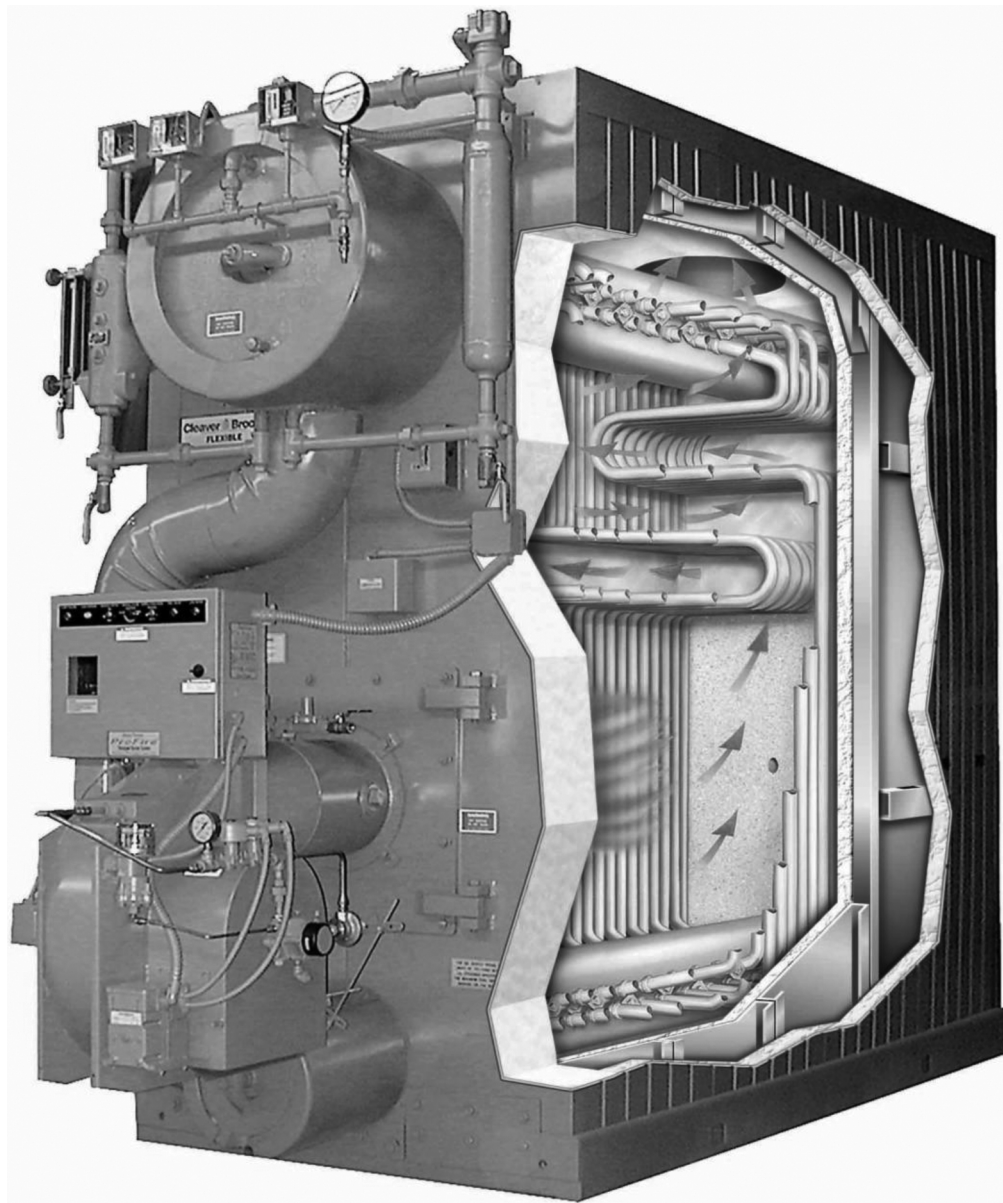


FIG. A.V.7
COMMERCIAL WATERTUBE BOILER
(COURTESY OF CLEAVER-BROOKS INC.)

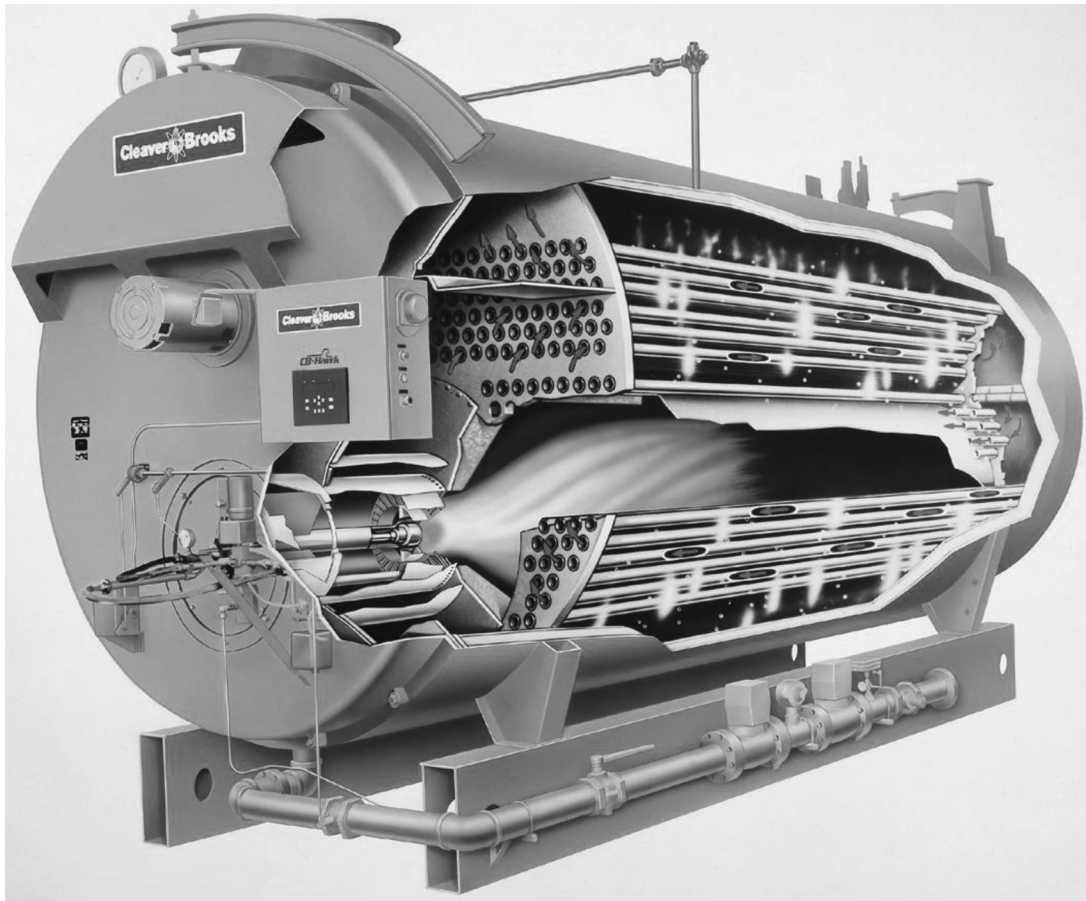


FIG. A.V.8
SCOTH MARINE FIRETUBE BOILER
(COURTESY OF CLEAVER-BROOKS INC.)

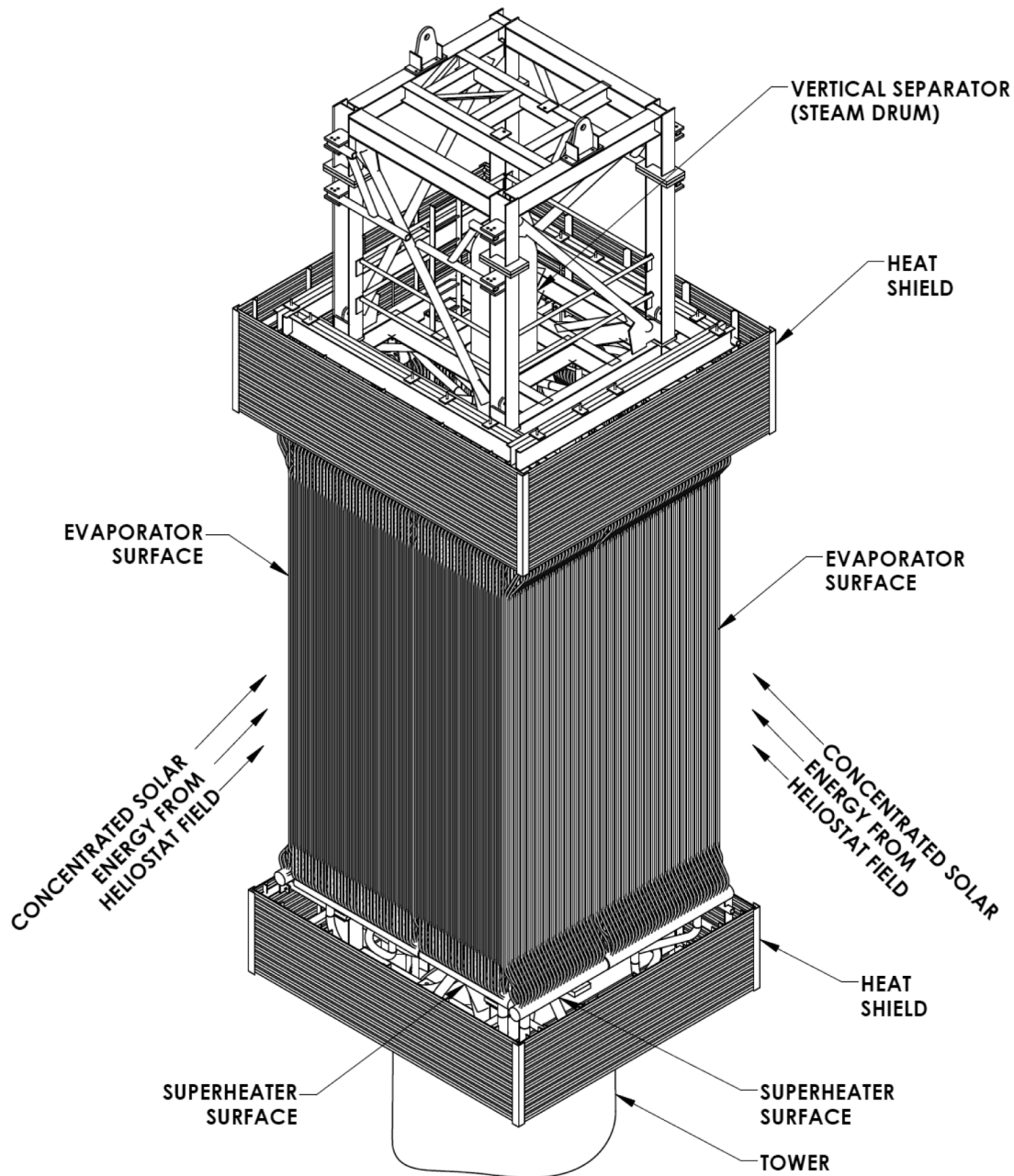


FIG. A.V.9
SOLAR "FIRED" BOILER
(COURTESY OF ESOLAR)

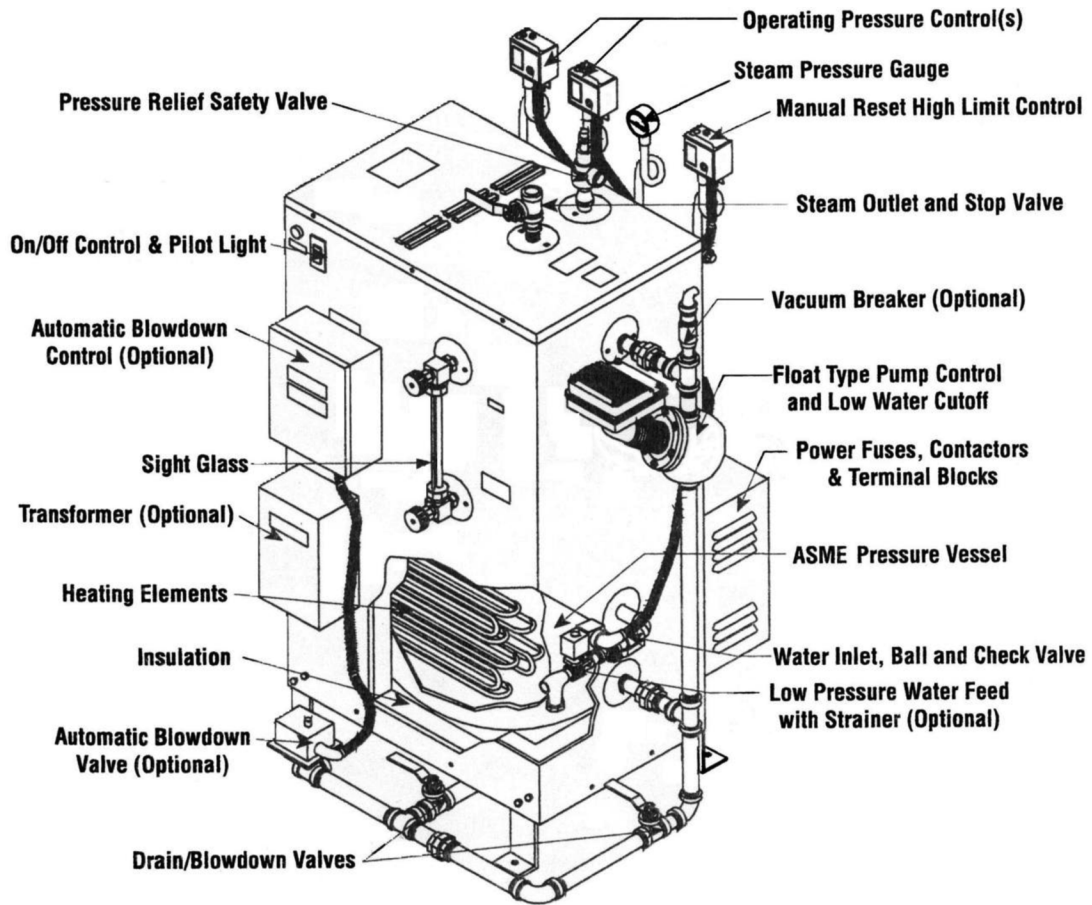


FIG. A.V.10
MINIATURE ELECTRIC BOILER
(COURTESY OF CHROMALOX INC.)

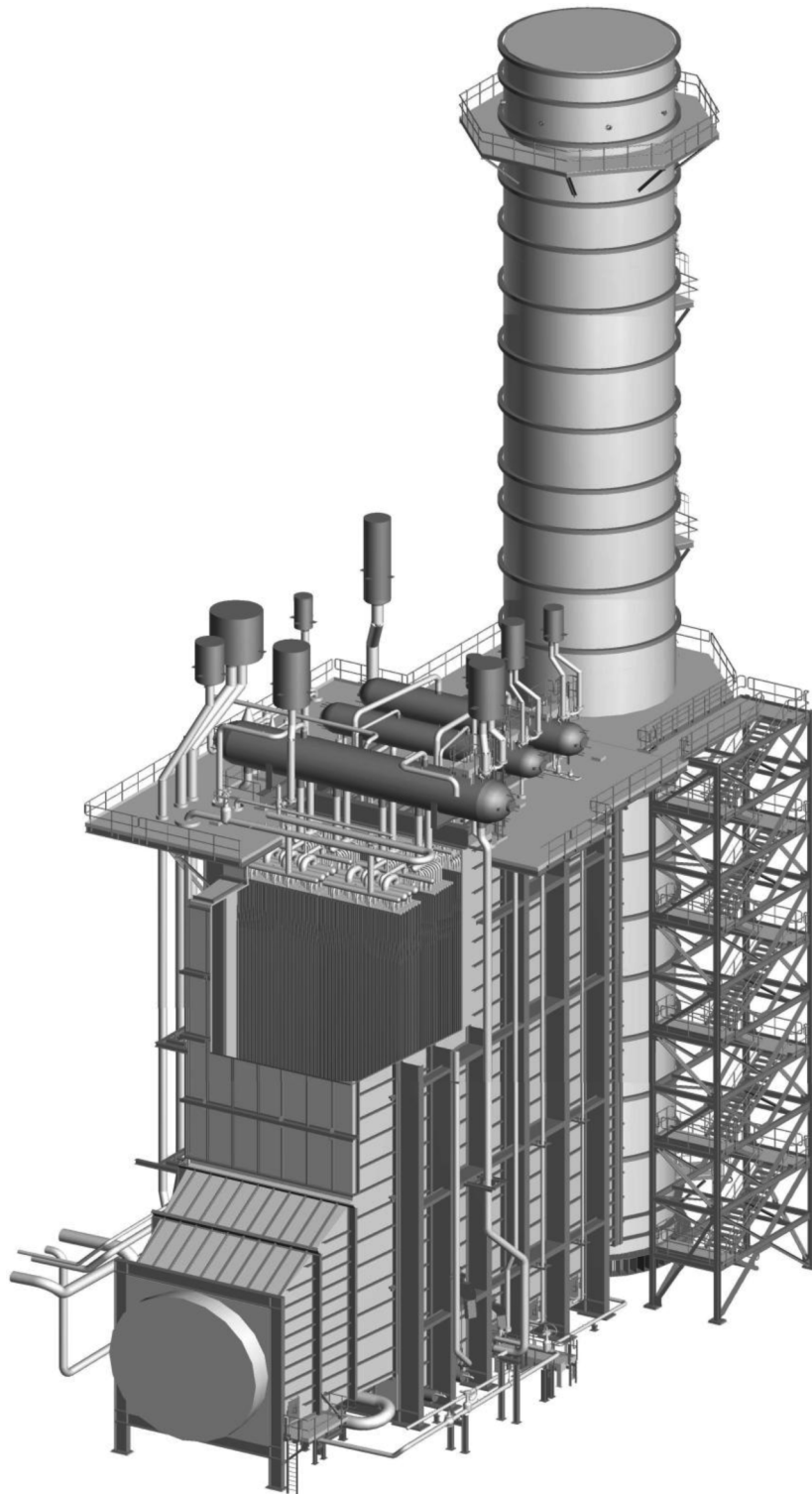


FIG. A.V.11
HEAT RECOVERY STEAM GENERATOR
(COURTESY OF ALSTOM POWER, INC.)

INDEX OF INTERPRETATIONS REFERENCED IN TEXT, THEIR MAJOR SUBJECTS AND ABSTRACTS

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I-81-26	PG-29. Compensation for flued manholes. Reiterates PG-29 requirements for extra head thickness for flued manholes; prohibits use of PG-33 compensation rules for such openings.	11, 76, 78
I-81-27	PG-99. Hydrostatic test pressure. Permits maximum hydrostatic test pressure to be exceeded when manufacturer demonstrates to the satisfaction of the AI that no component has been overstressed.	145

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I-86-69	PG-99. Painting of pressure parts before hydrostatic test.	149
I-86-82	Tube-to-header connection using only a single fillet weld with no additional mechanical support such as provided by expanding the tube is not permitted. This is one of several interpretations on this subject (I-79-18 and I-92-86 are two others), which are not based on any explicit provision of Section I. See discussion under Interpretations on Welding in Chapter 6.	133
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I-92-20	Preamble, PG-27. Fired boiler; separate economizer, corrosion allowance. Advises that: A waste heat boiler using exhaust from a combustion turbine supplemented intermittently by a duct burner is classified as a fired boiler. A separate economizer or preheater outside the limits of boiler external piping, with design pressure and temperature below 160 psi and 250°F, is outside the scope of Section I. Section I does not mandate a corrosion allowance.	12
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I-92-77	Table PW-39. Exemption from PWHT for circumferential weld. Advises that welds joining nozzle to shell or header are not considered to qualify. (See also I-92-23.)	128
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I-92-83	PG-55.2. Marking of nonpressure parts. Advises that no transfer of product marking is required for nonpressure parts cut from weldable material, such as lugs or hangers.	30
I-92-86	PW-16. Welded connections with single fillet welds. Advises that attachment of a nozzle by a single fillet weld, either to the inside or outside of a vessel, is not permitted. This is one of several interpretations on this subject (I-79-18 and I-86-82 are two others), which are not based on any explicit provision of Section I. See discussion under Interpretations on Welding in Chapter 6.....	133
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I-95-04	PG-60.1.1. Remote level indicator. Advises that a drum level transmitter with a remote readout is considered a remote level indicator.	204
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I-95-07	PG-60.1. Remote water level indication on computer monitor. Advises that computer display of drum water level may be considered an independent remote level indication only if the display is continuous and doesn't require a keystroke to become visible. (See also I-92-63.)	205
I-95-08	PG-11, PG-77. Identification of materials and miscellaneous pressure parts during and after construction. Advises that except for the special identification requirements of PG-77, identification markings required by the material specification and by PG-11 need not remain visible either during or after construction, provided the quality control system provides methods acceptable to the AI for assuring that only the intended material is used in Code construction.	30
I-95-17	PG-104. Pipe bending by organization not authorized to use a Code symbol stamp. Advises that an S or PP stamp holder may subcontract the bending of pipe to an organization without a Code symbol stamp, provided the stamp holder's quality control system covers the subcontracted activity.	168
I-95-22	PG-61.1. Redundancy of feedwater supply during boiler operation for boiler firing solid fuel not in suspension, equipped with two independent means of feeding water, not susceptible to the same interruption. Section I does not prohibit continued operation of the boiler following loss of one of the independent means of feeding water. Section I establishes the feedwater arrangements that must be provided; as a construction code it does not impose rules covering boiler operation.....	201
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