Pressure Vessel Inspection Code: In-service Inspection, Rating, Repair, and Alteration

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Suggested revisions are invited and should be submitted to the Standards Department, API, 200 Massachusetts Avenue, NW, Suite 1100, Washington, DC 20001, standards@api.org.

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1 Scope

1.1 General Application

1.1.1 Coverage

This inspection code covers the in-service inspection, repair, alteration, and rerating activities for pressure vessels and the pressure-relieving devices (PRDs) protecting these vessels. This inspection code applies to all hydrocarbon and chemical process vessels that have been placed in service unless specifically excluded per 1.2.2; however, it could also be applied to process vessels in other industries at owner-operator discretion. This includes:

a) vessels constructed in accordance with an applicable construction code [e.g., ASME *Boiler and Pressure Vessel Code* (*BPVC*)]; where a pressure vessel has been constructed to the American Society of Mechanical Engineers (ASME) *Section VIII Code*, API 510 is intended to apply to Divisions 1 and 2 and not Division 3;

b) vessels constructed without a construction code (noncode vessels);

c) vessels constructed and approved as jurisdictional-special based upon jurisdiction acceptance of particular design, fabrication, inspection, testing, and installation;

d) nonstandard vessels.

However, vessels that have been officially decommissioned (i.e. no longer are an asset of record from a financial/accounting standpoint) are no longer covered by this "in-service inspection" code. Abandoned-in-place vessels may still need some amount of inspection and/or risk mitigation to assure they do not become a hazard because of continuing deterioration. Pressure vessels temporarily out of service and preserved for potential future use are still covered by this code.

The ASME *BPVC* and other recognized construction codes are written for new construction; however, most of the technical requirements for design, welding, nondestructive examination (NDE), and materials can be applied to the inspection, rerating, repair, and alteration of in-service pressure vessels. If for some reason an item that has been placed in service cannot follow the construction code because of its new construction orientation, the requirements for design, material, fabrication, and inspection shall conform to API 510 rather than to the construction code. If in-service vessels are covered by requirements in the construction code and API 510 or if there is a conflict between the two codes, the requirements of API 510 shall take precedence. As an example of the intent of API 510, the phrase "applicable requirements of the construction code" has been used in API 510 instead of the phrase "in accordance with the construction code."

1.1.2 Intent

The application of this inspection code is restricted to owner-operators that employ or have access to the following technically qualified individuals and organizations:

a) an authorized inspection agency;

b) a repair organization;

c) an engineer;

d) an inspector;

e) examiners.

Inspectors are to be certified as stated in this inspection code (see Annex B). Since other codes covering specific industries and general service applications already exist (e.g., NB-23), the refining and petrochemical industry has developed this inspection code to fulfill their own specific requirements for vessels and PRDs that fit within the restrictions listed in the scope.

The intent of this code is to specify the in-service inspection and condition-monitoring program needed to determine the integrity of pressure vessels and PRDs. The program should provide reasonably accurate and timely assessments to determine if any changes in the condition of pressure equipment could compromise continued safe operation. The owner-operators shall respond to any inspection results that require corrective actions to assure the continued safe operation of pressure vessels and PRDs.

This code does not cover source inspection of newly fabricated pressure vessels. Refer to API RP 588 *Recommended Practice for Source Inspection and Quality Surveillance of Fixed Equipment* for guidance on the surveillance of supplier vendors fabricating and/or repairing pressure vessels that will be installed on site. Owner-operators may engage the services of individuals qualified and certified in accordance with API RP 588 or this code.

1.1.3 Limitations

Adoption and use of this inspection code does not permit its use in conflict with any prevailing regulatory requirements. However, if the requirements of this code are more stringent than the requirements of the regulation, then the requirements of this code shall govern.

1.2 Specific Applications

1.2.1 Exploration and Production (E&P) Vessels

All pressure vessels used for E&P service [e.g., drilling, producing, gathering, transporting, lease processing, and treating liquid petroleum, natural gas, and associated salt water (brine)] may be inspected under the alternative rules set forth in Section 9. Except for Section 6, all of the sections in this inspection code are applicable to pressure vessels in E&P service. The alternative rules in Section 9 are intended for services that may be regulated under safety, spill, emission, or transportation controls by the U.S. Coast Guard; the Office of Hazardous Materials Transportation of the U.S. Department of Transportation (DOT), and other units of DOT; the Bureau of Ocean Energy Management, Regulation, and Enforcement, formerly the Minerals Management Service of the U.S. Department of the Interior; state and local oil and gas agencies; or any other regulatory commission.

1.2.2 Excluded and Optional Services

Vessels excluded from the specific requirements of this inspection code are listed in Annex A. However, each owner-operator has the option of including any excluded pressure vessel in their inspection program as outlined in this code.

Some vessels exempted in accordance with the criteria in ASME *BPVC*, *Section VIII, Division 1* should be considered for inclusion based on risk (probability and consequence of failure) as determined by the owner-operator. An example of such vessels might be vacuum flashers in refining service or other large vessels operating in vacuum service.

1.2.3 Recognized Technical Concepts

For inspection planning and engineering assessment of in-service pressure vessels, this inspection code recognizes the applicability of fitness-for-service (FFS) assessment and risk-based inspection (RBI) methodologies. API 579-1/ ASME FFS-1 provides detailed assessment procedures for specific types of damage referenced in this code. API RP 580 provides guidelines for conducting a risk-based assessment program. API RP 581 provides a method of conducting RBI in accordance with the principles in API RP 580.

2 Normative References

The following documents are referred to in the text in such a way that some or all of their content constitutes requirements of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any addenda) applies.

API 510, *Inspector Certification Examination Body of Knowledge*

API Recommended Practice 571, *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*

API Recommended Practice 572, *Inspection of Pressure Vessels*

API Recommended Practice 576, *Inspection of Pressure-relieving Devices*

API Recommended Practice 577, *Welding Inspection and Metallurgy*

API Recommended Practice 578, *Material Verification Program for New and Existing Alloy Piping Systems*

API Standard 579-1/*ASME FFS-1, Fitness-For-Service*

API Recommended Practice 580, *Risk-Based Inspection*

API Recommended Practice 581, *Risk-Based Inspection Methodology*

API Recommended Practice 582, *Welding Guidelines for the Chemical, Oil, and Gas Industries*

API Recommended Practice 583, *Corrosion Under Insulation and Fireproofing*

API Recommended Practice 584, *Integrity Operating Windows*

API Recommended Practice 585, *Pressure Equipment Integrity Incident Investigations*

API Recommended Practice 751, *Safe Operation of Hydrofluoric Acid Alkylation Units*

API Recommended Practice 939-C, *Guidelines for Avoiding Sulfidation (Sulfidic) Corrosion Failures in Oil Refineries*

API Recommended Practice 941, *Steels for Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemical Plants*

API Recommended Practice 2201, *Safe Hot Tapping Practices for the Petroleum and Petrochemical Industries*

ASME PCC-1,[1] *Guidelines for Pressure Boundary Bolted Flange Joint Assembly*

ASME PCC-2, *Repair of Pressure Equipment and Piping*

ASME *Boiler and Pressure Vessel Code, Section II: Materials*

ASME *Boiler and Pressure Vessel Code, Section V: Nondestructive Examination*

ASME *Boiler and Pressure Vessel Code, Section VIII: Rules for Construction of Pressure Vessels; Division 1*

ASME *Boiler and Pressure Vessel Code, Section VIII: Rules for Construction of Pressure Vessels; Division 2: Alternative Rules*

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1 American Society of Mechanical Engineers, Two Park Avenue, New York, New York 10016-5990, www.asme.org.

ASME *Boiler and Pressure Vessel Code, Section IX: Welding and Brazing Qualifications*

ASNT CP-189,[2] *Standard for Qualification and Certification of Nondestructive Testing Personnel*

ASNT SNT-TC-1A, *Personnel Qualification and Certification in Nondestructive Testing*

3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

For the purposes of this code, the following terms and definitions apply.

3.1.1
abandoned-in-place
A pressure vessel meeting all of the following: has been decommissioned with no intention for future use; has been completely de-inventoried/purged of hydrocarbon/chemicals; and is physically disconnected (e.g., air-gapped) from all energy sources and/or other piping/equipment but remains in place.

3.1.2
alteration
A physical change in any component that has design implications that affect the pressure-containing capability of a pressure vessel beyond the scope described in existing data reports. The following should not be considered alterations: any comparable or duplicate replacement; the addition of any reinforced nozzle less than or equal to the size of existing reinforced nozzles; and the addition of nozzles not requiring reinforcement.

3.1.3
applicable construction code
The code, code section, or other recognized and generally accepted engineering standard or practice to which the pressure vessel was built or deemed by the owner-operator or the engineer to be most appropriate for the situation.

3.1.4
authorization
Approval/agreement to perform a specific activity (e.g., repair) prior to the activity being performed.

3.1.5
authorized inspection agency
Any one of the following:

a) the inspection organization of the jurisdiction in which the pressure vessel is used;

b) the inspection organization of an insurance company licensed or registered to write pressure vessel insurance;

c) the inspection organization of an owner-operator of pressure vessels who maintains an inspection organization for his/her equipment only and not for vessels intended for sale or resale;

d) an independent organization or individual under contract to and under the direction of an owner-operator and recognized or otherwise not prohibited by the jurisdiction in which the pressure vessel is used. The owner-operator's inspection program shall provide the controls necessary when contract inspectors are used.

[2] American Society for Nondestructive Testing International Service Center, PO Box 28518, 1711 Arlingate Lane, Columbus, Ohio, 43228-0518, www.asnt.org.

3.1.6
authorized pressure vessel inspector
An employee of an authorized inspection agency who is qualified and certified to perform inspections under this inspection code, including Annex B. Whenever the term “inspector” is used in API 510, it refers to an authorized pressure vessel inspector.

3.1.7
condition-monitoring location
CML
A designated area on pressure vessels where periodic examinations are conducted to directly assess and monitor the condition of the vessel using a variety of examination methods and techniques based on damage mechanism susceptibility. CMLs may contain one or more examination points and can be a single small area on a pressure vessel, e.g., a 50 mm (2 in.) diameter spot or plane through a section of a nozzle where recording points exist in all four quadrants of the plane.

NOTE CMLs include but are not limited to what were previously called thickness-monitoring locations (TMLs).

3.1.8
construction code
The code or standard to which a vessel was originally built, such as API/ASME (now out of date), ASME *BPVC*, API, or state special/non-ASME or any other construction code to which the vessel was built.

3.1.9
controlled-deposition welding
CDW
Any welding technique used to obtain controlled grain refinement and tempering of the underlying heat-affected zone in the base metal. Various controlled-deposition techniques, such as temper bead (tempering of the layer below the current bead being deposited) and half bead (requiring removal of one-half of the first layer), are included (see 8.6).

3.1.10
corrosion allowance
Additional material thickness available to allow for metal loss during the service life of the vessel component.

3.1.11
corrosion rate
The rate of metal loss due to erosion, erosion/corrosion, and/or the chemical reaction(s) with the environment, either internal and/or external.

3.1.12
corrosion specialist
A person acceptable to the owner-operator, who is knowledgeable and experienced in the specific process chemistries, damage mechanisms, materials selection, corrosion mitigation methods, corrosion-monitoring techniques, and their impact on equipment.

3.1.13
corrosion under fireproofing
CUF
Corrosion of piping, pressure vessels, and structural components resulting from water trapped under fireproofing.

3.1.14
corrosion under insulation
CUI
External corrosion of piping, pressure vessels, and structural components resulting from water trapped under insulation. External chloride stress corrosion cracking (ECSCC) of austenitic and duplex stainless steel under insulation is also classified as CUI damage.

3.1.15
cyclic service
Refers to service conditions that could result in cyclic loading and produce fatigue damage or failure (e.g., cyclic loading from pressure, thermal, and/or mechanical loads). Other cyclic loads associated with vibration could arise from such sources as impact, turbulent flow vortices, resonance in compressors, and wind, or any combination thereof (see 5.4.4).

3.1.16
damage mechanism
Any type of deterioration encountered in the refining and chemical process industry that can result in flaws/defects that can affect the integrity of vessels (e.g., corrosion, cracking, erosion, dents, and other mechanical, physical, or chemical impacts). See API RP 571 for a comprehensive list and description of damage mechanisms.

3.1.17
decommissioned
Termination of pressure vessel from its service. A pressure vessel at this stage of its life-cycle is permanently removed from service, and either removed from the process unit or abandoned-in-place.

3.1.18
defect
A discontinuity or discontinuities that by nature or accumulated effect render a part or product unable to meet minimum applicable acceptance standards or specifications (e.g., total crack length). The term designates rejectability.

3.1.19
deferral
An approved and documented postponement of an inspection, test, or examination (see 6.6.3.5).

3.1.20
design temperature
The temperature used for the design of the pressure vessel per the applicable construction code.

3.1.21
documentation
Records containing descriptions of specific vessel design, personnel training, inspection plans, inspection results, NDE, repair, alteration, rerating and pressure-testing activities, FFS assessments, procedures for undertaking these activities, or any other information pertinent to maintaining the integrity and reliability of vessels.

3.1.22
due date
The date established by the owner-operator in accordance with this code, whereby an inspection, test, examination, or inspection recommendation falls due. The date may be established by rule-based inspection methodologies (e.g., fixed intervals, retirement half-life interval, retirement date), risk-based methodologies (e.g., RBI target date), FFS analysis results, owner-operator inspection agency practices/procedures/guidelines, or any combination thereof.

3.1.23
engineer
Pressure vessel engineer.

3.1.24
examination point
recording point
measurement point
test point
A more specific location within a CML. CMLs may contain multiple examination points, for example, a vessel nozzle may be a CML and have multiple examination points (e.g., an examination point in all four quadrants of the CML on the nozzle).

NOTE The term “test point” is no longer in use, as “test” refers to mechanical or physical tests, e.g. tensile tests or pressure tests.

3.1.25
examinations
A process by which an examiner or inspector investigates a component of the pressure vessel using NDE in accordance with approved NDE procedures (e.g., inspection of a CML, quality control (QC) of repair areas).

3.1.26
examiner
A person who assists the inspector by performing specific NDE on pressure vessel components and evaluates to the applicable acceptance criteria but does not evaluate the results of those examinations in accordance with API 510 unless specifically trained and authorized to do so by the owner-operator.

3.1.27
external inspection
A visual inspection performed from the outside of a pressure vessel to find conditions that could impact the vessel’s ability to maintain pressure integrity or conditions that compromise the integrity of the supporting structures (e.g., ladders, platforms, supports). The external inspection may be done either while the vessel is operating or while the vessel is out of service and can be conducted at the same time as an on-stream inspection.

3.1.28
fitness-for-service evaluation
FFS evaluation
A methodology whereby flaws and other deterioration/damage or operating conditions contained within a pressure vessel are assessed in order to determine the integrity of the vessel for continued service.

3.1.29
general corrosion
Corrosion distributed approximately uniform over the surface of the metal.

3.1.30
heat-affected zone
HAZ
The portion of the base metal whose mechanical properties or microstructure have been altered by the heat of welding or thermal cutting.

3.1.31
hold point
A point in the repair or alteration process beyond which work may not proceed until the required inspection or NDE has been performed.

3.1.32
idle
Pressure vessel not currently operating, but remains connected to piping, electrical or instrumentation (may be blinded or blocked in).

NOTE An idled pressure vessel is considered in-service and is still subject to the requirements of this code.

3.1.33
imperfection
Flaws or other discontinuities noted during inspection or examination that may or may not exceed the applicable acceptance criteria.

3.1.34
indication
A response or evidence resulting from the application of an NDE that may be nonrelevant, flawed, or defective upon further analysis.

3.1.35
industry-qualified UT angle beam examiner
A person who possesses an ultrasonic angle beam qualification from API (e.g., API QUTE/QUSE detection and sizing tests) or an equivalent qualification approved by the owner-operator.

NOTE Rules for equivalency are defined on the API ICP website.

3.1.36
in-service
The life-cycle stage of a pressure vessel that begins after initial installation (where typically initial commissioning or placing into active service follows) and ends at decommissioning. Pressure vessels that are idle in an operating site and vessels that are not currently in operation because of a process outage are still considered in-service pressure vessels.

NOTE Does not include pressure vessels that are still under construction or in transport to a site prior to being placed in operation nor does it include pressure vessels that have been decommissioned.

3.1.37
in-service inspection
All inspection activities associated with an in-service pressure vessel (after installation, but before it is decommissioned).

3.1.38
inspection
The external, internal, or on-stream evaluation (or any combination of the three) of the condition of a vessel conducted by the authorized inspector or his/her designee in accordance with this code.

3.1.39
inspection code
A reference to the API 510 code.

3.1.40
inspection plan
A strategy defining how and when a pressure vessel or PRD will be inspected, examined, repaired, and/or maintained (see 5.1).

3.1.41
inspector
A shortened title for an authorized pressure vessel inspector qualified and certified in accordance with this code.

3.1.42
integrity operating window
IOW
Established limits for process variables (parameters) that can affect the integrity of the equipment if the process operation deviates from the established limits for a predetermined amount of time (see 4.1.4).

3.1.43
internal inspection
An inspection performed from the inside of a pressure vessel using visual and/or NDE techniques.

3.1.44
jurisdiction
A legally constituted governmental administration that may adopt rules relating to pressure vessels.

3.1.45
localized corrosion
Corrosion that is typically confined to a limited or isolated area(s) of the metal surface of a pressure vessel.

3.1.46
major repair
Any work not considered an alteration that removes and replaces a major part of the pressure boundary other than a nozzle (e.g., replacing part of the shell or replacing a vessel head). If any of the restorative work results in a change to the design temperature, minimum allowable temperature (MAT), or maximum allowable working pressure (MAWP), the work shall be considered an alteration, and the requirements for rerating shall be satisfied.

3.1.47
management of change
MOC
A documented management system for review and approval of changes (both physical and process) to pressure vessels prior to implementation of the change. The MOC process includes involvement of inspection personnel who may need to alter inspection plans as a result of the change.

3.1.48
manufacturer's data report
A document that contains data and information from the manufacturer of the pressure vessel that certifies the materials of construction contained in the vessel meet certain material property requirements, tolerances, etc. and are in accordance with specified standards.

3.1.49
maximum allowable working pressure
MAWP
The maximum gauge pressure permitted at the top of a pressure vessel in its operating position for a designated temperature. This pressure is based on calculations using the minimum (or average pitted) thickness for all critical vessel elements (exclusive of thickness designated for corrosion) and adjusted for applicable static head pressure and nonpressure loads (e.g., wind and seismic). The MAWP may refer to either the original design or a rerated MAWP obtained through an FFS assessment.

3.1.50
minimum design metal temperature/minimum allowable temperature
MDMT/MAT
The lowest permissible metal temperature for a given material at a specified thickness based on its resistance to brittle fracture. In the case of MAT, it may be a single temperature or an envelope of allowable operating temperatures as a function of pressure. It is generally the minimum temperature at which a significant load can be applied to a pressure vessel as defined in the applicable construction code, e.g., ASME *BPVC*, *Section VIII, Division 1*, Paragraph UG-20(b). It might also be obtained through an FFS evaluation.

3.1.51
National Board
The National Board of Boiler and Pressure Vessel Inspectors.

3.1.52
noncode vessel
A vessel not fabricated to a recognized construction code and meeting no known recognized standard.

3.1.53
nonpressure boundary
Components of the vessel that do not contain the process pressure (e.g., trays, tray rings, distribution piping, baffles, nonstiffening insulation support rings, clips, and davits).

3.1.54
nonstandard vessel
A vessel fabricated to a recognized construction code but that has lost its nameplate or stamping.

3.1.55
on-stream
A condition in which a pressure vessel has not been prepared for an internal inspection (see “on-stream inspection”).

3.1.56
on-stream inspection
An inspection performed from the outside of a pressure vessel while it is on-stream using NDE procedures to establish the suitability of the pressure boundary for continued operation.

3.1.57
overdue inspections
Inspections for in-service vessels still in operation that have not been performed by their documented due dates documented in the inspection plan and have not been deferred by a documented deferral process (see 6.7).

3.1.58
overdue inspection recommendations
Recommendations for repair or other mechanical integrity purposes for vessels still in operation that have not been completed by their documented due dates, which have not been deferred by a documented deferral process (see 6.8).

3.1.59
owner-operator
An owner or operator of pressure vessels who exercises control over the operation, engineering, inspection, repair, alteration, maintenance, pressure testing, and rerating of those pressure vessels.

3.1.60
plate lining
Metal plates welded to the inside of the pressure vessel wall for the purpose of protecting the vessel construction material from interaction with process fluids. Normally, plates are of a more corrosion-resistant or erosion-resistant alloy than the vessel wall and provide additional corrosion/erosion resistance. In some instances, plates of a material of construction similar to the vessel wall are used for specific operating periods in which corrosion and/or erosion rates are predictable.

3.1.61
postweld heat treatment
PWHT
Treatment that consists of heating an entire weldment or vessel to a specified elevated temperature after completion of welding in order to relieve the effects of welding heat, such as to reduce residual stresses, reduce hardness, stabilize chemistry, and/or slightly modify properties.

3.1.62
pressure boundary
That portion of the pressure vessel that contains the pressure retaining elements joined or assembled into a pressure-tight, fluid-containing vessel (e.g., typically the shell, heads, and nozzles) but excluding nonpressure boundary items (e.g., supports, skirts, and clips).

3.1.63
pressure test
A test performed on pressure vessels that have been in service and that have undergone an alteration or repair to the pressure boundary(s) to indicate the integrity of the pressure components are still compliant with the original construction code. The pressure test can be hydrostatic, pneumatic, or a combination thereof.

3.1.64
pressure vessel
A container designed to withstand internal and/or external pressure/loads. This pressure may be imposed by the application of heat from a direct or indirect source, or by any combination thereof. This definition includes heat exchangers, air coolers, columns, towers, unfired steam generators (boilers), and other vapor generating vessels that use heat from the operation of a processing system or other indirect heat source.

NOTE Specific limits and exemptions of equipment covered by this inspection code are provided in Section 1 and Annex A.

3.1.65
pressure vessel engineer
A person acceptable to the owner-operator who is knowledgeable and experienced in the engineering disciplines associated with evaluating mechanical and material characteristics that affect the integrity and reliability of pressure vessels. The pressure vessel engineer, by consulting with appropriate specialists, should be regarded as a composite of all entities needed to properly assess the technical requirements. Wherever the term "engineer" is used in this code, it refers to a pressure vessel engineer.

3.1.66
procedures
A document that specifies or describes how an activity is to be performed. It may include methods to be employed, equipment or materials to be used, qualifications of personnel involved, and sequence of work.

3.1.67
quality assurance
QA
All planned, systematic, and preventative actions specified to determine if materials, equipment, or services will meet specified requirements so that equipment will perform satisfactorily in service. The minimum contents of a QA inspection manual for in-service inspection are outlined in 4.1.2.

3.1.68
quality control
QC
Those physical activities conducted to check conformance with specifications in accordance with the QA plan.

3.1.69
R-stamp
An "R" Certificate of Authorization issued by the National Board.

3.1.70
repair
The work necessary to restore a vessel to a condition suitable for safe operation at the design conditions. If any of the restorative work results in a change to the design temperature, minimum design metal temperature (MDMT), or MAWP, the work shall be considered an alteration, and the requirements for rerating shall be satisfied. Any welding, cutting, or grinding operation on a pressure-containing component not specifically considered an alteration is considered a repair.

3.1.71
repair organization
An organization that is qualified to make the repair by meeting the criteria of 4.3.

3.1.72
required thickness
The minimum thickness without corrosion allowance for each element of a pressure vessel based on the appropriate design code calculations and code allowable stress that consider internal and external pressure, mechanical, and structural loadings including the effects of static head. Alternately, required thickness can be reassessed and revised using FFS analysis in accordance with API 579-1/ ASME FFS-1.

3.1.73
rerating
A change in either the design temperature rating, the MDMT rating, or the MAWP rating of a vessel. The design temperature and MAWP of a vessel may be increased or decreased because of a rerating. Derating (rerating below original design conditions) is a permissible way to provide for additional corrosion allowance.

3.1.74
risk-based inspection
RBI
An inspection planning methodology that incorporates a risk assessment process that considers both the probability of failure and consequence of failure. The methodology is primarily aimed at managing unacceptable risks, reducing loss of containment failures, and optimization of the inspection strategy.

3.1.75
scanning nondestructive examination
Examination methods designed to find the thinnest spot or all defects in a specified area of a pressure vessel such as profile radiography of nozzles, scanning ultrasonic techniques, and/or other suitable nondestructive examination (NDE) techniques that will reveal the scope and extent of localized corrosion or other deterioration.

3.1.76
same or similar service
A designation in which two or more pressure vessels are installed in parallel, comparable, or identical service and their process and environmental conditions have been consistent over a period of years based on the inspection criteria being assessed such that the damage mechanisms and rates of damage are comparable.

EXAMPLE 1 Parallel service: A process or part of a process connected in parallel having comparable configuration with analogous and readily recognized similarities.

EXAMPLE 2 Identical service: A designation where there is agreement that the configuration, process, and operating regime, metallurgy, and environmental conditions are all the same, such that expected degradation characteristics are expected to be the same.

3.1.77
strip lining
Strips of metal plates welded to the inside of the vessel wall for the purpose of protecting the vessel construction material from interaction with process fluids. Normally the strips are of a more corrosion-resistant or erosion-resistant alloy than the vessel wall and provide additional corrosion/erosion resistance. This is similar to plate lining except narrower strips are used instead of larger plates.

3.1.78
temper embrittlement
The reduction in fracture toughness due to a metallurgical change that can occur in some low-alloy steels (e.g., 2 1/4Cr-1Mo) as a result of long-term exposure in the temperature range of about 345 °C to 575 °C (650 °F to 1070 °F).

3.1.79
temporary repair
Repairs made to pressure vessels to restore sufficient integrity to continue safe operation until permanent repairs are conducted (see 8.2).

3.1.80
testing
Within this document, testing generally refers to either pressure testing, whether performed hydrostatically, pneumatically, or a combination hydrostatic/pneumatic, or mechanical testing to determine such data as material hardness, strength, and notch toughness. Testing, however, does not refer to examination using NDE techniques such as liquid penetrant examination (PT), magnetic particle examination (MT), ultrasonic examination (UT), radiographic examination (RT), etc.

3.1.81
tightness test
A pressure test conducted on pressure vessels after maintenance or repair activities to indicate the equipment is leak free and is conducted at a test pressure determined by the owner-operator that is not higher than the MAWP.

3.1.82
transition temperature
The temperature at which a material fracture mode changes from ductile to brittle.

3.1.83
VR-stamp
A "VR" Certificate of Authorization issued by the National Board.

3.2 Acronyms and Abbreviations

For the purposes of this code, the following acronyms and abbreviations apply.

ASME *Code*	ASME *Boiler and Pressure Vessel Code*, including its addenda and code cases
CCD	corrosion control document
CDW	controlled-deposition welding
CML	condition-monitoring location
CUF	corrosion under fireproofing
CUI	corrosion under insulation
DMW	dissimilar metal welds
E&P	exploration and production
ECSCC	external chloride stress corrosion cracking
ET	eddy current examination
FFS	fitness-for-service
GMAW	gas metal arc welding
GTAW	gas tungsten arc welding
IOW	integrity operating window
MAT	minimum allowable temperature
MAWP	maximum allowable working pressure
MDMT	minimum design metal temperature
MOC	management of change
MT	magnetic particle examination
NDE	nondestructive examination
PAUT	phased array ultrasonic examination

PEI	pressure equipment integrity
PMI	positive material identification
PQR	procedure qualification record
PRD	pressure-relieving device
PT	liquid penetrant examination
PWHT	postweld heat treatment
QA	quality assurance
QC	quality control
RBI	risk-based inspection
RT	radiographic examination
SMAW	shielded metal arc welding
TOFD	time-of-flight diffraction ultrasonic examination
UT	ultrasonic examination
WPQ	welder performance qualification
WPS	welding procedure specification

4 Owner-operator Inspections Organization

4.1 Owner-operator Organization Responsibilities

4.1.1 General

An owner-operator of pressure vessels shall exercise control of the vessel and pressure relief device inspection program, inspection frequencies, and maintenance. The owner-operator is responsible for the function of an authorized inspection agency in accordance with the provisions of this code. The owner-operator inspection organization shall also control activities relating to the rating, repair, alteration, and engineering assessments of its pressure vessels and relief devices.

4.1.2 Owner-operator Systems and Procedures

An owner-operator organization is responsible for developing, documenting, implementing, executing, and assessing pressure vessel/pressure-relieving device inspection systems, inspection/repair systems, and procedures that meet the requirements of this inspection code. These systems and procedures will be contained and maintained in a quality assurance (QA) inspection/repair management system and shall include at least the following:

a) organization and reporting structure for inspection personnel;

b) documenting of inspection and QA procedures;

c) documenting and reporting inspection, examination, and test results;

d) developing and documenting inspection plans;

e) developing and documenting risk-based assessments applied to inspection activities;

f) establishing and documenting the appropriate inspection intervals;

g) corrective action for inspection and test results;

h) internal auditing for compliance with the QA inspection manual;

i) review and approval of drawings, design calculations, engineering assessments, and specifications for repairs, alterations, and reratings;

j) ensuring all jurisdictional requirements for pressure vessel inspection, repairs, alterations, and rerating are continuously met;

k) reporting to the inspector any process changes or other conditions that could affect pressure vessel integrity;

l) training requirements for inspection personnel regarding inspection tools, techniques, and technical knowledge base;

m) controls necessary such that only qualified welders and procedures are used for all repairs and alterations;

n) controls necessary that all repairs and alterations are performed in accordance with this inspection code and applicable specifications;

o) controls necessary that only qualified NDE personnel and procedures are used;

p) controls necessary that only materials conforming to the applicable construction code are used for repairs and alterations through material verification and/or positive material identification;

q) controls necessary that all inspection measurement, NDE, and testing equipment are properly maintained and calibrated;

r) controls necessary that the work of contract inspection or repair organizations meets the same inspection requirements as the owner-operator organization;

s) internal auditing requirements for the QC system for PRDs;

t) management shall have an appropriate requirement and work process to increase the confidence that inspectors have an annual vision test and are capable of reading standard J-1 letters on standard Jaeger eye test type charts for near vision.

4.1.3 Management of Change (MOC)

The owner-operator is responsible for implementing and executing an effective MOC process that reviews and controls changes to either the process or to the hardware. An effective MOC review process is vital to the success of any pressure vessel integrity management program as it allows the inspection group to:

1) be able to address issues concerning the adequacy of the pressure equipment design and current condition for the proposed changes;

2) anticipate changes in corrosion or other types of damage; and

3) update the inspection plan and records to account for those changes.

When pressure equipment integrity may be affected, the MOC process shall include the appropriate inspection, materials/corrosion, and mechanical engineering experience and expertise in order to effectively identify pressure equipment design issues and forecast what changes might affect pressure vessel integrity. The inspection group shall be involved in the approval process for changes that may affect pressure vessel integrity. Changes to the hardware and the process shall be included in the MOC process to improve its effectiveness in managing pressure equipment integrity.

4.1.4 Integrity Operating Windows (IOWs)

The owner-operator should implement and maintain an effective program for creating, establishing, and monitoring integrity operating windows. IOWs are implemented to avoid process parameter exceedances that may have an unanticipated impact on pressure equipment integrity. Future inspection plans and intervals have historically been based on prior measured corrosion rates resulting from past operating conditions. Without an effective IOW and process control program, there often is no warning of changing operating conditions that could affect the integrity of equipment or validation of the current inspection plan. Deviations from and changes of trends within established IOW limits should be brought to the attention of inspection/engineering personnel so they may modify or create new inspection plans depending upon the seriousness of the exceedance.

IOWs should be established for process parameters (both physical and chemical) that could impact equipment integrity if not properly controlled. Examples of the process parameters include temperatures, pressures, fluid velocities, pH, flow rates, chemical or water injection rates, levels of corrosive constituents, chemical composition, etc. IOWs for key process parameters may have both upper and lower limits established, as needed. Particular attention to monitoring IOWs should also be provided during start-ups, shutdowns, and significant process upsets. See API RP 584 for more information on issues that may assist in the development of an IOW program.

4.1.5 Pressure Equipment Integrity (PEI) Incident Investigations

The owner-operator should investigate PEI incidents and near-misses (near-leaks) to determine causes (root, contributing, and direct) that may result in updates to the associated inspection program, IOW, corrosion control document (CCD), etc. If PEI incidents and near-misses are recognized, investigated, and the causes identified, then future leaks and failures of pressure equipment can be minimized or prevented. API RP 585 covers PEI incident investigations and provides owner-operators with guidelines for developing, implementing, sustaining, and enhancing an investigation program for PEI incidents.

4.1.6 Corrosion Control Document (CCD)

The owner-operator may develop a CCD for each process unit in accordance with the work process contained in API RP 970 or alternate methodology outlining all the mechanical integrity damage mechanisms to which the equipment and piping in the process unit are susceptible. The CCDs or alternate documents identifying credible damage mechanisms should be available to stakeholders (e.g., inspectors, mechanical engineers, process engineers) that have a role in fixed equipment integrity.

4.2 Engineer

The pressure vessel engineer is responsible to the owner-operator to make certain that activities involving design, engineering review and analysis, or evaluation of pressure vessels and PRDs are as required in this inspection code and as specified by the owner-operator.

4.3 Repair Organization

The repair organization is responsible to the owner-operator and shall provide the materials, equipment, QC, and workmanship necessary to maintain and repair the vessel or PRD in accordance with the requirements of this inspection code. The repair organization shall meet one of the following criteria:

a) the holder of a valid ASME Certificate of Authorization that authorizes the use of an appropriate ASME *BPVC* symbol stamp;

b) the holder of another recognized code of construction certificate that authorizes the use of an appropriate construction code symbol stamp;

c) the holder of a valid R-stamp issued by the National Board for repair of pressure vessels;

d) the holder of a valid VR-stamp issued by the National Board for repair and servicing of relief valves;

e) an owner-operator of pressure vessels and/or relief valves who repairs his or her own equipment in accordance with this code;

f) a repair contractor whose qualifications are acceptable to the pressure vessel owner-operator;

g) an individual or organization authorized by the legal jurisdiction to repair pressure vessels or service PRDs.

4.4 Inspector

The inspector is responsible to the owner-operator to assure the inspection, NDE, repairs, alterations, and pressure-testing activities meet API 510 code requirements. The inspector shall be directly involved in the inspection activities, especially visual inspections, which in most cases will require field activities to confirm procedures and inspection plans are followed. The inspector may be assisted in performing inspections by properly trained and qualified individuals acceptable to the owner-operator (e.g., examiners and operating or maintenance personnel). However, all NDE results shall be evaluated and accepted in accordance with API 510 by the inspector, who will then make appropriate recommendations for repairs, replacements, or fitness for continued service. Inspectors shall be certified in accordance with the provisions of Annex B. The inspector can be an employee of the owner-operator or be a contractor acceptable to the owner-operator.

4.5 Examiners

4.5.1 The examiner shall perform the NDE in accordance with job requirements, NDE procedures, and owner-operator specifications.

4.5.2 The examiner does not need API 510 inspector certification and does not need to be an employee of the owner-operator. The examiner does need to be trained and competent in the NDE procedures being used and may be required by the owner-operator to prove competency by holding certifications in those procedures. Examples of certifications that may be required include ASNT SNT-TC-1A, ASNT CP-189, CGSB, and AWS QC1. Inspectors conducting their own examinations with NDE techniques shall also be appropriately qualified in accordance with owner-operator requirements.

4.5.3 The examiner's employer shall maintain certification records of the examiners employed, including dates and results of personnel qualifications. These records shall be available to the inspector, who is responsible to the owner-operator to determine all NDE examiners are properly qualified for the work they perform.

4.6 Other Personnel

Operating, maintenance, engineering (process and mechanical), or other personnel who have special knowledge or expertise related to particular pressure vessels and/or PRDs shall be responsible for timely notification to the inspector or engineer of potential issues that may affect vessel integrity such as the following:

a) any action that requires MOC;

b) operations outside defined IOW;

c) changes in source of feedstock and other process fluids that could increase process-related corrosion rates or introduce new damage mechanisms;

d) vessel failures, repair actions conducted, and failure analysis reports;

e) cleaning and decontamination methods used or other maintenance procedures that could affect pressure vessel integrity;

f) reports that may come to their attention of other plants' experiences with similar or same service pressure vessel failures;

g) any unusual conditions that may develop (e.g., noises, leaks, vibration, movements, insulation damage, external vessel deterioration, support structure deterioration, and significant bolting corrosion);

h) any engineering evaluation, including FFS assessments, that might require current or future actions to maintain mechanical integrity until next inspection.

4.7 Inspection Organization Audits

Each owner-operator organization should be audited periodically to determine if the authorized inspection agency is meeting the requirements of this inspection code. The audit team should consist of people experienced and competent in the application of this code. The audit team should typically be from another owner-operator plant site or central office or from a third-party organization experienced and competent in refining and/or petrochemical process plant inspection programs or a combination of third-party and other owner-operator sites. However, periodic self-auditing by those directly involved in the site inspection organization is also recommended.

The audit team should determine in general whether:

a) the requirements and intent of this inspection code are being met;

b) owner-operator responsibilities are being properly discharged;

c) documented inspection plans are in place for covered pressure vessels;

d) intervals and extent of inspections are adequate for covered pressure vessels;

e) general types of inspections and surveillance are being adequately applied;

f) inspection data analysis, evaluation, and recording are adequate;

g) repairs, reratings alterations, and engineering assessments comply with this code.

The owner-operator should receive a report of the audit team's findings. When nonconformances are found, the owner-operator authorized inspection agency shall take the necessary corrective actions. Each organization needs to establish a system for tracking and completion of corrective actions generated from audit findings. The resolution of the audit findings should be made available to the audit team for review. This information should also be reviewed during subsequent audits.

5 Inspection, Examination, and Pressure-testing Practices

5.1 Inspection Plans

5.1.1 General

An inspection plan shall be established for all pressure vessels and PRDs within the scope of this code. Inspection plans should be developed to cover all credible damage mechanisms, as well as code and jurisdictional requirements and may include multiple types of inspections such as: internal, on-stream, external, and thickness examinations.

5.1.2 Development of an Inspection Plan

5.1.2.1 The inspection plan shall be developed by the inspector and/or engineer. A corrosion specialist shall be consulted to identify credible damage mechanisms and susceptible areas for localized corrosion, cracking, corrosion under insulation/corrosion under fireproofing (CUI/CUF) and metallurgical damage. See 5.4.1.

5.1.2.2 The inspection plan is developed from the analysis of several sources of data. Equipment shall be evaluated based on present or credible types of damage mechanisms. The methods and the extent of NDE shall be evaluated to assure the specified techniques can adequately identify the damage mechanism and the extent and severity of damage. Examinations shall be scheduled at intervals that consider the following:

a) type of damage mechanism;

b) rate of damage progression;

c) tolerance of the equipment to the type of damage;

d) probability of the NDE method to identify the damage;

e) maximum intervals as defined in codes and standards;

f) extent of previous examination (equipment history);

g) recent operating history, including IOW exceedances;

h) MOC records that may impact inspection plans;

i) RBI assessments (where available).

5.1.2.3 The inspection plan shall be developed using the most appropriate sources of information. Inspection plans shall be reviewed and amended as needed. Sources of information may include process unit CCDs, RBI assessments, IOWs, past inspections, past failures (industry, company and site) and risk analysis on vessels in similar service, MOC documents, or documents referenced in Section 2 of this code. See API RP 571, API RP 572, and API RP 583 for more information on issues that may assist in the development of inspection plans.

5.1.3 Contents of an Inspection Plan

The inspection plan shall contain the inspection tasks and schedule required to monitor damage mechanisms and assure the mechanical integrity of the equipment (pressure vessel or PRD). The plan should:

a) define the type(s) of inspection needed (e.g., internal, external, etc);

b) identify the next inspection date for each inspection type;

c) describe the inspection and NDE techniques;

d) describe the extent and locations of inspection and NDE;

e) describe the surface-cleaning requirements needed for inspection and examinations;

f) describe the requirements of any needed pressure test (e.g., type of test, test pressure, and duration);

g) describe any previously planned repairs;

h) describe specific considerations due to process or mechanical changes (e.g., MOCs), IOW exceedances, and other operating deviations that occurred since the prior inspection.

Generic inspection plans based on industry standards and practices may be used as a starting point but should be developed to provide sufficient detail to direct the designated inspector to examine all areas of potential concern as indicated by the corrosion specialist and/or process unit CCD as well as historic inspection and maintenance records for the vessel. The inspection plan may include historical and design documents. The contents of the plan should be readily accessible from inspection data systems.

5.1.4 Additional Contents of an Inspection Plan

Inspection plans may also contain other details to assist in understanding the rationale for the plan and in executing the plan. Some of these details may include:

a) describing the types of damage anticipated or experienced in the equipment;

b) defining the location of the damage; and

c) defining any special access requirements.

5.1.5 Execution of Inspection Plan

The inspection plan created by the responsible inspector and/or engineer should be executed by an inspector and examiner assigned to conduct the inspection at the designated time. Deviations from the inspection plan should be approved by the responsible owner-operator inspector, engineer, or designee. Reference 7.8 regarding expectation for reports and records.

5.2 Risk-based Inspection (RBI)

5.2.1 General

RBI can be used to determine inspection intervals and the type and extent of future inspection/examinations. An RBI assessment determines risk by combining the probability and the consequence of equipment failure. When an owner-operator chooses to conduct an RBI assessment, it shall include the minimum program requirements as established by API RP 580. API RP 581 details an RBI methodology that has all of the key elements defined in API RP 580. Identifying and evaluating credible damage mechanisms, current equipment condition, and the effectiveness of the past inspections are important steps in assessing the probability of a pressure vessel failure. Identifying and evaluating the process fluid(s), potential injuries, environmental damage, equipment damage, and equipment downtime are important steps in assessing the consequence of a pressure vessel failure. Identifying and implementing IOWs for key process variables is an important adjunct to RBI, as well as any other method of planning and scheduling inspections (see 4.1.4).

5.2.2 Probability Assessment

The probability assessment shall be based on all forms of damage that could reasonably be expected to affect a vessel in any particular service. Examples of those damage mechanisms include: internal or external metal loss from localized or general corrosion, all forms of cracking, and any other forms of metallurgical, corrosion, or mechanical damage (e.g., fatigue, embrittlement, and creep) Additionally, the effectiveness of the inspection practices, tools, and techniques used for finding the credible damage mechanisms shall be evaluated. Other factors that should be considered in a probability assessment include:

a) appropriateness of the materials of construction;

b) vessel design conditions, relative to operating conditions;

c) appropriateness of the design codes and standards used;

d) effectiveness of corrosion-monitoring programs;

e) the quality of maintenance and inspection QA/QC programs;

f) both the structural and pressure-retaining requirements;

g) operating conditions, both past and projected.

Equipment failure data will also be important information for this assessment.

5.2.3 Consequence Assessment

The consequence of a release is dependent on type and amount of process fluid contained in the equipment. The consequence assessment shall consider the potential incidents that may occur as a result of fluid release, the size of a potential release, and the type of a potential release (includes explosion, fire, or toxic exposure.) The assessment shall also determine the potential incidents that may occur as a result of fluid release, which may include health effects, environmental damage, equipment damage, and equipment downtime.

5.2.4 Documentation

It is essential that all RBI assessments be thoroughly documented in accordance with API RP 580, clearly defining all the factors contributing to both the probability and consequence of a failure of the vessel. After an RBI assessment is conducted, the results can be used to establish the vessel inspection plan and better define the following:

a) the most appropriate inspection and NDE methods, tools, and techniques;

b) the extent of NDE (e.g., percentage of vessel to examine);

c) the interval for internal, external, and on-stream inspections;

d) the need for pressure testing after damage has occurred or after repairs/alterations have been completed;

e) the prevention and mitigation steps to reduce the probability and consequence of a vessel failure (e.g., repairs, process changes, and inhibitors).

5.2.5 Frequency of RBI Assessments

When RBI assessments are used to set vessel inspection intervals, the assessment shall be updated after each vessel inspection as defined in API RP 580. The RBI assessment shall also be updated each time process or hardware changes are made that could significantly affect damage rates or damage mechanisms and anytime an unanticipated failure or inspection discovery occurs due to a damage mechanism.

5.3 Preparation for Inspection

5.3.1 General

Safety precautions are important in pressure vessel inspection and maintenance activities because some process fluids are harmful to human health. Personal protective equipment shall be worn that will protect the inspection personnel from specific hazards when required either by regulations, the owner-operator, or the repair organization. Pressure vessels are enclosed spaces, and internal activities involve exposure to all of the hazards of confined space entry. Prior to entering a vessel, the vessel shall be positively isolated from all sources of liquids, gases, vapors, radiation, and electricity. The vessel shall be drained, purged, cleaned, ventilated, and the atmosphere inside it gas tested before it is entered. Before entering a vessel, individuals shall obtain permission from the responsible operating personnel. All safe entry procedures required by the operating site and the applicable jurisdiction shall be followed. The individual entering the vessel is responsible to assure him/herself all applicable safety procedures, regulations, and permits for confined space entry are being followed prior to their entry of the vessel. Applicable regulations (e.g., those administered by OSHA) govern many aspects of vessel entry and shall be followed. In addition, the owner-operator's safety procedures shall be reviewed and followed. Refer to API RP 572 for more information on inspection safety.

5.3.2 Records Review

Before performing any of the required API 510 inspections, inspectors shall familiarize themselves with prior history of the vessels for which they are responsible. In particular, they should review the vessel's prior inspection results, prior repairs, current inspection plan, as well as any engineering evaluations, and/or other similar service inspections. A general overview of the types of damage and failure modes experienced by pressure equipment is provided in API RP 571 and API 579-1/ASME FFS-1.

5.4 Inspection for Different Types of Damage Mechanisms and Failure Modes

5.4.1 Pressure vessels are susceptible to various types of damage by several mechanisms. Appropriate inspection techniques for each of the credible damage mechanisms for each pressure vessel shall be part of the inspection plans. API RP 571 describes common damage mechanisms and inspection techniques to identify them. Some example damage mechanisms are as follows:

a) General and localized metal loss and pitting corrosion:

1) sulfidation and high-temperature H_2S/H_2 corrosion—refer to API RP 571 and API RP 939-C;

2) oxidation—refer to API RP 571;

3) microbiologically influenced corrosion—refer to API RP 571;

4) naphthenic acid corrosion—refer to API RP 571;

5) erosion/erosion-corrosion—refer to API RP 571;

6) galvanic corrosion—refer to API RP 571;

7) atmospheric corrosion—refer to API RP 571;

8) CUI—refer to API RP 571;

9) cooling water corrosion—refer to API RP 571;

10) boiler water and steam condensate corrosion—refer to API RP 571;

11) soil corrosion—refer to API RP 571;

12) ammonium bisulfide, ammonium chloride, and amine hydrochloride corrosion—refer to API RP 571;

13) CO_2 corrosion—refer to API RP 571.

b) Surface-connected cracking:

1) mechanical fatigue—refer to API RP 571;

2) thermal fatigue—refer to API RP 571;

3) caustic stress corrosion cracking—refer to API RP 571;

4) polythionic acid stress corrosion cracking—refer to API RP 571;

5) wet H_2S damage (sulfide stress cracking [SSC])—refer to API RP 571;

6) chloride stress corrosion cracking—refer to API RP 571.

c) Subsurface cracking:

1) wet H_2S damage (hydrogen-induced cracking [HIC]/ stress-oriented hydrogen-induced cracking [SOHIC])—refer to API RP 571;

d) High-temperature microfissuring/microvoid formation and eventual macrocracking:

   1) high-temperature hydrogen attack—refer to API RP 571 and API RP 941;

   2) creep and stress rupture—refer to API RP 571.

e) Metallurgical changes:

   1) graphitization—refer to API RP 571;

   2) temper embrittlement—refer to API RP 571;

   3) hydrogen embrittlement—refer to API RP 571.

f) Blistering:

   1) wet H_2S damage (hydrogen blistering)—refer to API RP 571.

5.4.2 The presence or potential of damage in a vessel is dependent upon its material of construction, design, construction, and operating conditions. The inspector should be familiar with these conditions and with the causes and characteristics of potential defects and/or damage mechanisms.

5.4.3 More detailed information and more damage mechanisms concerning corrosion, cracking, etc., including critical factors, appearance, and typical inspection and monitoring techniques are found in API RP 571. Additional recommended inspection practices for various damage mechanisms are described in API RP 572.

5.4.4 Vessels in cyclic service (cycles of pressure, temperature, or combinations of both pressure and temperature) should be evaluated for potential fatigue cracking failures and have appropriate inspections planned. The following considerations should be evaluated where applicable for vessels in cyclic service.

a) The fatigue design criteria from the original code of construction and any special precautions and/or fabrication details (e.g., ground flush welds, limits on weld peaking, integral reinforcement, magnetic particle/dye penetrant examinations of weld surface, and volumetric weld examination).

b) The types of vessel internal and external attachments and nozzles (e.g., fillet welded attachments and nozzle reinforcing pads), longitudinal and circumferential weld joint peaking, repairs, modifications, and damage (e.g., dents, bulges, and gouges), and their potential for fatigue cracking due to the stress intensification at these locations. An engineering analysis may be required to determine the high-stress locations for further evaluation and inspection planning.

c) The potential for internal or external corrosion (e.g., CUI) and environmental/stress corrosion cracking and their potential effect on the fatigue life of the vessel.

d) The appropriate NDE and inspection frequency to detect fatigue cracking (e.g., external ultrasonic angle beam flaw detection, external and/or internal wet fluorescent magnetic particle examination, time-of-flight diffraction ultrasonics) and the need for out-of-roundness measurements and measurements of weld seams for peaking or flattening.

Typical examples of vessels in cyclic service include coke drums, mole sieves, and pressure swing adsorbers.

5.4.5 Pressure vessels in HF alkylation service require special attention for inspection planning that is detailed in API RP 751.

5.4.6 Heavy-wall process vessels (over 5 cm [2 in.] thick) should have minimum allowable temperature (MAT) and operating procedures established to minimize the potential for brittle fracture during heat up and cool down cycles.

5.5 Types of Inspection and Surveillance for Pressure Vessels

5.5.1 Types of Inspection and Surveillance

Different types of inspections, examinations, and surveillance are appropriate depending on the circumstances and the pressure vessel. These include the following:

a) internal inspection,

b) on-stream inspection,

c) external inspection,

d) thickness examination,

e) CUI/CUF inspection,

f) operator surveillance.

Inspections shall be conducted in accordance with the inspection plan for each vessel. Refer to Section 6 for the interval/frequency and extent of inspection. Corrosion and other damage identified during inspections and examinations shall be characterized, sized, and evaluated per Section 7 with deviations from the plan being approved by the inspector, pressure vessel engineer, or qualified designee.

5.5.2 Pressure Vessel Internal Inspection

5.5.2.1 General

The internal inspection shall be performed by an inspector in accordance with the inspection plan; other personnel acceptable to the owner-operator (e.g., NDE examiner) may assist (but not replace) the inspector in the internal inspection. An internal inspection is conducted from inside the vessel and shall provide a thorough check of internal pressure boundary surfaces for damage. Inspection through manway or inspection port can be substituted for internal inspections when the vessel is too small to safely enter or when the use of remote visual inspection techniques (e.g., borescope, drones, and robotic crawlers) can visually inspect the areas of potential degradation on the internal vessel surface. Remote visual inspection techniques can be used if approved by the inspector and owner-operator. The inspector shall be present during the inspection along with reviewing and accepting the data from these inspection techniques. Remote visual inspection techniques may aid the check of internal surfaces. How much of the internal surfaces could be thoroughly inspected should be reported and documented.

A primary goal of the internal inspection is to find damage that cannot be found by regular monitoring of external condition-monitoring locations (CMLs) during on-stream inspections. Specific surface and/or volumetric NDE techniques (e.g., wet fluorescent magnetic particle testing, alternating current field measurement, eddy current examination [ET]), and PT) may be required by the owner-operator to find damage specific to the vessel or service conditions and when needed shall be specified in the inspection plan. API RP 572 provides more information on pressure vessel internal inspection and should be used when performing this inspection. Additionally, refer to API RP 572 for extensive information on internal inspection of columns/towers.

5.5.2.2 Pressure Vessel Internals

When vessels are equipped with removable internals, internals may need to be removed, to the extent necessary, to allow inspection of pressure boundary surfaces. The internals need not be removed completely as long as reasonable assurance exists that damage in regions rendered inaccessible by the internals is not occurring to an extent beyond that found in more accessible parts of the vessel. Part of the inspection planning process should include the determination of how much of the removable internals are to be removed for inspection purposes. Inspection of vessel internals (for functionality and integrity) that are not part of the pressure boundary may be included in the inspection plan or conducted by others e.g., process engineers/technicians.

5.5.2.3 Internal Deposits and Linings

The inspector, in consultation with the corrosion specialist, should determine when it is necessary to remove deposits or linings to perform adequate inspections. Whenever operating deposits, such as coke, are normally permitted to remain on a vessel surface, it is important to determine whether these deposits adequately protect the vessel or do not cause deterioration of the surface. Spot examinations at selected areas, with the deposit thoroughly removed, may be required to determine the vessel surface condition.

Internal linings (e.g., refractory, strip linings, plate linings, coatings) should be thoroughly examined. If internal linings are in good condition and there is no reason to suspect damage is occurring behind them, it is not necessary to remove linings during the internal inspection. If the lining appears damaged, bulged, or cracked, it may be advisable to remove portions of the linings to investigate the condition of the lining and the vessel surface beneath. External NDE techniques may be advisable to explore for damage beneath linings. Refer to API RP 572 for more information on inspection of pressure vessel linings.

5.5.3 On-stream Inspection of Pressure Vessels

5.5.3.1 The on-stream inspection may be required by the inspection plan. All on-stream inspections should be conducted by either an inspector or examiner in accordance with the inspection plan. All on-stream inspection work performed by an examiner shall be authorized and approved by the inspector. When on-stream inspections of the pressure boundary are specified, the appropriate NDE techniques shall be specified to detect the damage mechanisms and their associated flaw types identified in the inspection plan.

5.5.3.2 The inspection may include a number of examination techniques to assess damage mechanisms associated with the service. Techniques used in on-stream inspections are chosen for their ability to identify particular damage mechanisms from the exterior and their capabilities to perform in the on-stream conditions of the pressure vessel (e.g., metal temperatures). The thickness examination described in 5.5.5 would typically be part of an on-stream inspection.

There are inherent limitations when applying external NDE techniques trying to locate internal damage. Issues that can affect those limitations include:

a) type of material of construction (alloy);

b) type of parent material (plate, pipe, casting);

c) weldments;

d) nozzles, support saddles, reinforcing plates;

e) internal attachments;

f) internal lining or cladding;

g) physical access and equipment temperature;

h) limitations inherent to the selected NDE technique to detect the damage mechanism;

i) examination surface condition (e.g., significant pitting or poor surface preparation/grinding).

5.5.3.3 On-stream inspection may be acceptable in lieu of internal inspection for vessels under the specific circumstances defined in 6.5.2. In situations where on-stream inspection is acceptable, such inspection may be conducted either while the vessel is depressurized or pressured.

5.5.4 External Inspection of Pressure Vessels

5.5.4.1 General

5.5.4.1.1 Visual external inspections are normally performed by an inspector; however, other qualified personnel may conduct the external inspection when their qualifications to do so are acceptable to the owner-operator. In such cases, the persons performing the external inspection in accordance with API 510 shall be qualified with appropriate training as specified by the owner-operator.

5.5.4.1.2 External inspections are performed to check the condition of the outside surface of the vessel, insulation systems, painting and coating systems, supports, and associated structure, and to check for leakage, hot spots, vibration, the allowance for expansion, and the general alignment of the vessel on its supports. During the external inspection, particular attention should be given to welds used to attach components (e.g., reinforcement plates and clips) for cracking or other defects. Any signs of leakage should be investigated to determine the cause for the leakage. Normally, weep holes in reinforcing plates should remain open to provide visual evidence of leakage as well as to prevent pressure buildup behind the reinforcing plate. External inspections should note any areas where insulation coverings and/or penetrations may be allowing moisture ingress on vessels susceptible to CUI.

A checklist should be developed by or made available to the responsible inspector or engineer that includes all items that should be checked and noted by the designated inspector conducting the external inspection.

5.5.4.1.3 Vessels shall be examined for visual indications of bulging, out-of-roundness, sagging, and distortion. If any distortion of a vessel is suspected or observed, the overall dimensions of the vessel shall be checked to determine the extent of the distortion. API RP 572 provides more information on external inspection of pressure vessels and should be used when conducting this inspection. Any personnel who observe vessel deterioration should report the condition to the owner-operator and inspector/engineer responsible.

5.5.4.2 Inspection of Buried Vessels

Buried vessels shall be inspected to determine their external surface condition. The inspection interval shall be based on an assessment of the cathodic protection system (if any exists) effectiveness and on corrosion rate information obtained from one or more of the following methods:

a) during maintenance activity on connecting piping of similar material;

b) from the periodic examination of similarly buried corrosion test coupons of like material;

c) from representative portions of the actual vessel; or

d) from a vessel in similar circumstances.

Excavation of buried vessels for the purpose of inspection should take into account the potential for damaging the coating and or cathodic protection systems. Particular attention needs to be taken for buried vessel in light hydrocarbon service. Consideration should be made for the remaining life of the external coating, the known or unknown quality of the coating installation, the long-term effectiveness of the cathodic protection, the quality of the installation of the overburden materials, and other mitigation activities. Scanning UT thickness readings and/or other appropriate scanning NDE methods for determining the condition of the external surface condition could be conducted on the vessel internally to monitor for external corrosion. Refer to API RP 571 on soil corrosion when conducting inspections of buried vessels.

5.5.5 Thickness Examination

5.5.5.1 Thickness measurements are taken to verify the thickness of vessel components. This data is used to determine the corrosion rates and remaining life of the vessel. Thickness measurements shall be obtained by the inspector or examiner as required and scheduled by the inspection plan.

5.5.5.2 Although thickness measurements are not required to be obtained while the pressure vessel is on-stream, on-stream thickness monitoring is the primary method for monitoring corrosion rates.

5.5.5.3 The inspector shall review the results of the thickness inspection data to look for possible anomalies and should consult with a corrosion specialist when the short-term corrosion rate changes significantly from the previous identified rate to determine the cause. Appropriate responses to accelerated corrosion rates may include additional thickness readings, UT scans in suspect areas, corrosion/process monitoring, and revisions to the vessel's inspection plan. Whenever corrosion rates change significantly or other unanticipated deterioration is found, an investigation should be performed. Information contained in the CCD, IOW limits, and or RBI documents may need to be updated as an outcome of the investigation (see 4.1.5).

5.5.5.4 The owner-operator is responsible to assure all individuals taking thickness readings are trained and qualified as a UT TM (thickness-monitoring) examiner in accordance with the applicable procedure used during the examination. The procedure(s) used for thickness monitoring should address and provide guidance in detection and characterization of corrosion, pitting, laminations, blisters, and inclusions. The training should include the variables known to affect the quality of thickness measurements. See API RP 572 for more information on thickness examination techniques.

5.5.5.5 Regarding CMLs on insulated vessels, care should be taken so that CML sealing systems, e.g., CML plugs, are kept in place to provide adequate sealing of insulation covers to avoid ingress of moisture that could cause CUI.

5.5.6 CUI/CUF Inspection

5.5.6.1 Susceptible Temperature Range for CUI

Inspection for CUI shall be considered for externally insulated vessels and those in intermittent service or operate at temperatures between:

a) –12 °C (10 °F) and 177 °C (350 °F) for carbon and low-alloy steels;

b) 60 °C (140 °F) and 177 °C (350 °F) for austenitic stainless steels;

c) 138 °C (280 °F) and 177 °C (350 °F) for duplex stainless steels.

Owner-operator should be aware vessel penetrations (e.g., nozzles and support) can go in and out of the CUI range (see API RP 583). The vessel may operate outside the CUI range and be deemed not susceptible to CUI whereas the metal temperature of penetrations may transition into the CUI range. This should be taken into account when assigning CUI susceptibility and documented in the inspection plan.

5.5.6.2 Susceptible Locations for CUI on Equipment

With carbon and low-alloy steels, CUI usually causes localized corrosion. However, vessels in sweating service may have general corrosion with localized corrosion occurring at locations with coating failure. With austenitic and duplex stainless steel materials, CUI is usually in the form of external chloride stress corrosion cracking. See API RP 583 for more information on inspection for ECSCC on insulated austenitic stainless steels. When developing the inspection plan for CUI inspection, the inspector should consider areas most susceptible to CUI but be aware that locations for CUI damage can be very unpredictable. On vessels, the most susceptible areas include:

a) above insulation or stiffening rings;

b) nozzles and manways;

c) other penetrations (e.g., ladder clips, supports);

d) damaged insulation with areas of potential water ingress;

e) areas with failed insulation caulking;

f) top and bottom heads;

g) other areas that tend to trap water.

If CUI damage is found, the inspector should inspect other susceptible areas on the vessel. See API RP 583 on CUI for more detailed information.

5.5.6.3 Insulation Removal

CUI damage may still be occurring underneath good condition external insulation and associated jacketing/cladding systems. CUI inspection may require removal of some or all insulation (i.e., removing selected windows in the insulation). If external coverings are in good condition and there is no reason to suspect damage behind them, it is not necessary to remove them for inspection of the vessel. It may be necessary to remove insulation for detection of CUI on pressure vessels due to the diameter limitations of traditional NDE techniques typically used for CUI on smaller diameters. The amount of insulation to be removed will depend on the risk of an incident being caused by CUI. For locations where insulation is not removed, API RP 583 provides guidance on NDE methods that can be applied to detect CUI/CUF under insulation.

Considerations on the need for insulation removal are not limited to but include:

a) consequences of CUI leakage;

b) history of CUI for the vessel or comparable equipment;

c) visual condition of the external covering and insulation;

d) evidence of fluid leakage (e.g., stains);

e) equipment in intermittent service;

f) condition/age of the vessel coating under insulation, if applicable;

g) potential for the type of insulation to absorb/hold more water (e.g., calcium silicate vs cellular glass);

h) ability to apply specialized NDE that can effectively locate CUI without insulation removal;

i) potential for damage due to vessels in sweating service.

Alternatively, shell thickness measurements done internally at typical CUI problem areas may be performed during internal inspections, but the inspector should be aware CUI damage is often highly localized and therefore may be difficult to detect from the inside diameter of a vessel.

5.5.6.4 CUF Inspection

For vessels with fireproofing installed over the vessel shell or structural supports, external inspections shall include checking for potential signs of CUF, e.g., looking for signs of fireproofing material deterioration, spalling, cracking, bulging, and stains from corrosion of exposed rebar. If damage is found, further investigation is warranted as deterioration can lead to ingress of moisture that may cause CUF of the vessel, supports, and/or reinforcing materials in the fireproofing. If significant damage is found, timely maintenance should be scheduled so that the fireproofing system will continue to perform as intended and the integrity of the vessel and/or supports is not compromised. API RP 2218 provides further guidance for inspection and maintenance of fireproofing. API RP 583 also addresses CUF inspection.

5.5.7 Operator Surveillance

When walking through the facility, operators should report anything unusual associated with pressure vessels and PRDs to the inspector or engineer. Such things include vibration, signs of leakage, unusual noises, insulation deterioration, relief device having opened, distortion, denting, temperature excursions, presence of rust stain coming out from under insulation, or other barriers or crevices (aka rust bleeding), etc.

5.6 Condition-monitoring Locations (CMLs)

5.6.1 General

CMLs are designated areas on pressure vessels where periodic examinations are conducted to monitor the presence and rate of damage. The type of CML selected and placement of CMLs shall consider the potential for localized corrosion and service-specific damage as described in 5.4. Examples of different types of CMLs include locations for thickness measurement, locations for stress corrosion cracking examinations, and locations for high-temperature hydrogen attack examinations.

5.6.2 CML Examinations

5.6.2.1 Each pressure vessel shall be monitored by conducting a representative number of examinations at CMLs to satisfy the requirements for an internal and/or on-stream inspection. For example, the thickness for all major components (shells, heads, cone sections) and a representative sample of vessel nozzles should be measured and recorded. Corrosion rates, the remaining life, and next inspection intervals should be calculated to determine the limiting component. CMLs with the highest corrosion rates and least remaining life shall be part of those included in next planned examinations.

5.6.2.2 Pressure vessels with high potential consequences if failure should occur and those subject to higher corrosion rates, localized corrosion, and high rates of damage from other mechanisms will normally have more CMLs and be monitored more frequently. The rate of corrosion/damage shall be determined from successive measurements and the next inspection interval appropriately established.

5.6.2.3 Where thickness measurements are obtained at CMLs, the minimum thickness at a CML can be located by ultrasonic measurements or radiography. Volumetric measuring techniques also can be used to identify thin areas that may then be measured by ultrasonic techniques or radiography. Additionally, when localized corrosion is expected or a concern, it is important that examinations are conducted using scanning methods such as profile radiography, density radiography, scanning ultrasonic techniques, and/or other suitable NDE techniques that will reveal the scope and extent of localized corrosion. When scanning with ultrasonics, scanning consists of taking several thickness measurements at the CML searching for localized thinning.

5.6.2.4 The thinnest reading or an average of several measurement readings taken within the area of an examination point shall be recorded and used to calculate the corrosion rates. If detailed thickness grids are needed in a specific CML to perform FFS assessments of the metal loss, refer to API 579-1/ASME FFS-1 for preparation of such thickness grids.

5.6.2.5 CMLs and examination points should be permanently recorded, (e.g., marked on inspection drawings and/or on the equipment) to allow repetitive measurements at the same CMLs. Repeating measurements at the same location improves accuracy of the calculated damage rate.

5.6.3 CML Selection and Placement

5.6.3.1 A decision on the type, number, and location of the CMLs should consider results from previous inspections, the patterns of corrosion and damage expected, and the potential consequence of loss of containment. CMLs should be distributed appropriately over the vessel to provide adequate monitoring coverage of major components and nozzles. Thickness measurements at CMLs are intended to establish general and localized corrosion rates in different sections of the vessel. For pressure vessels susceptible to damage mechanisms other than relatively general thinning such as localized corrosion, embrittlement and cracking mechanisms, corrosion specialists should be consulted about the appropriate placement and number of CMLs.

More CMLs should be selected for pressure vessels with any of the following characteristics:

a) higher potential for creating an immediate safety or environmental emergency in the event of a leak, unless the internal corrosion rate is known to be relatively uniform and low;

b) higher expected or experienced corrosion rates;

c) higher potential for localized corrosion.

Fewer CMLs can be selected for pressure vessels with any of the following three characteristics:

a) low potential for creating a safety or environmental emergency in the event of a leak;

b) relatively noncorrosive contents;

c) generally uniform corrosion rates.

5.6.3.2 CMLs may be eliminated or the number significantly reduced when the probability and/or consequence of failure is low (e.g., clean noncorrosive hydrocarbon service). In circumstances where CMLs will be substantially reduced or eliminated, a corrosion specialist should be consulted.

5.7 Condition-monitoring Methods

5.7.1 Examination Technique Selection

5.7.1.1 General

In selecting the technique(s) to use during a pressure vessel inspection, the possible types of damage for that vessel should be taken into consideration. The inspector should consult with a corrosion specialist or an engineer to help define the type of damage, the NDE technique, and extent of examination. Examples of NDE techniques that may be used include the following.

a) MT for cracks and other elongated discontinuities that extend to the surface of the material in ferromagnetic materials. ASME *Code*, Section V, Article 7 provides guidance on performing MT.

b) Penetrant testing, either florescent or visible, for detecting cracks, porosity, or pin holes that extend to the surface of the material and for outlining other surface imperfections, especially in nonmagnetic materials. ASME *Code, Section* V, Article 6 provides guidance on performing PT.

c) RT for detecting internal imperfections such as porosity, weld slag inclusions, cracks, and thickness of components. ASME *Code, Section V*, Article 2 provides guidance on performing RT.

d) Ultrasonic thickness measurement and flaw detection for detecting the thickness of components and for detecting internal and surface breaking cracks and other elongated discontinuities. ASME *Code*, *Section V,* Articles 4, 5, and 23 provide guidance on performing ultrasonic examination (UT).

e) Alternating current flux leakage examination technique for detecting surface-breaking cracks and elongated discontinuities.

f) ET for detecting localized metal loss, cracks, and elongated discontinuities. ASME *Code*, *Section V,* Article 8 provides guidance on performing ET.

g) Field metallographic replication for identifying metallurgical changes.

h) Acoustic emission examination for detecting structurally significant defects. ASME *Code, Section V,* Article 12 provides guidance on performing acoustic emission examination.

i) Infrared thermography for determining temperature of components.

j) Pressure testing for detecting through-thickness defects. ASME *Code, Section V*, Article 10 and ASME PCC-2, Article 501 provide guidance on performing leak testing.

k) Macrohardness and microhardness measurements using portable equipment for identifying variations in mechanical properties due to changes in material.

l) Advanced ultrasonic techniques (e.g., TOFD and PAUT) for detecting high-temperature hydrogen attack referenced in API RP 941.

Refer to API RP 572 for more information on examination techniques, API RP 571 for application inspection techniques per damage mechanism, and API RP 577 for more information on weld quality examination.

5.7.1.2 Surface Preparation

Adequate surface preparation is important for proper visual examination and for the satisfactory application of any NDE procedures, such as those mentioned above. The type of surface preparation required depends on the individual circumstances and NDE technique, but surface preparations such as wire brushing, grit or water blasting, chipping, grinding, polishing, etching, or a combination of these preparations may be required.

5.7.1.3 UT Angle Beam Examiners

The owner-operator shall specify industry-qualified UT angle beam examiners when the owner-operator requires the following where detection, characterization, and/or through-wall sizing is required of defects:

a) detection of interior surface (ID) breaking and internal flaws when inspecting from the external surface (OD); or

b) for cases where manual UT is used to examine welds in lieu of a pressure test.

Application examples for the use of industry-qualified UT angle beam examiners include monitoring known interior flaws from the external surface, checking for suspected interior flaws, and collecting data for FFS evaluations.

5.7.2 Thickness Measurement Methods

5.7.2.1 Corrosion may cause a uniform loss (a general, relatively even metal loss of a surface area) or localized loss (only occurring in specific isolated areas) or may cause a pitted appearance (an obvious, irregular surface metal loss). Uniform corrosion may be difficult to detect visually, so thickness measurements are usually necessary to determine its extent. Localized corrosion and pitted surfaces may be thinner than they appear visually, and when there is uncertainty about the original surface location or depth of metal loss, thickness determinations may also be necessary. Measurements may be obtained as follows.

a) Any suitable NDE, such as spot ultrasonic or profile RT, may be used as long as it will provide minimum thickness determinations. When a measurement method produces considerable uncertainty, other nondestructive thickness measurement techniques, such as ultrasonic A-scan, B-scan, or C-scan, may be employed.

b) The depth of corrosion may be determined by gauging from the uncorroded surfaces within the vessel when such surfaces are in the vicinity of the corroded area.

c) Ultrasonic thickness-measuring instruments usually are the most accurate means for obtaining thickness measurements. Proper repair of insulation and insulation weather coating following ultrasonic readings at CMLs is recommended to reduce potential for CUI. Where practical, radiographic profile techniques, which do not require removing insulation, may be considered as an alternative.

5.7.2.2 Ultrasonic scanning or radiographic profile techniques are preferred where corrosion is localized or the remaining thickness is approaching the required thickness.

5.7.2.3 Corrective procedures should be used when metal temperatures (typically above 65 °C [150 °F]) impact the accuracy of the thickness measurements obtained. Instruments, couplants, and procedures should be used that result in accurate measurements at the higher temperatures. Typically, procedures will involve calibrating with hot test plates or adjusting measurements by the appropriate temperature correction factor.

5.7.2.4 Inspectors and examiners should be aware of possible sources of measurement inaccuracies and make every effort to eliminate their occurrence. As a general rule, each of the NDE techniques will have practical limits with respect to accuracy. Factors that can contribute to reduced accuracy of ultrasonic measurements include the following:

a) improper instrument calibration;

b) external coatings or scale;

c) excessive surface roughness;

d) excessive “rocking” of the probe (on curved surfaces);

e) subsurface material flaws, such as laminations;

f) temperature effects (at temperatures above 65 °C [150 °F]);

g) small flaw detector screens;

h) doubling of the thickness response on thinner materials.

5.8 Pressure Testing

5.8.1 General

Refer to ASME PCC-2, Article 501 for more information on pressure testing.

5.8.2 When to Perform a Pressure Test

5.8.2.1 Pressure tests are not normally conducted as part of routine inspection. A pressure test is normally required after an alteration or major repair. After repairs (other than major repairs) are completed, a pressure test shall be applied if the inspector believes one is necessary and specifies it in the repair plan. Potential alternatives to pressure tests are outlined in 5.8.8.

5.8.2.2 Pressure tests are typically performed on an entire vessel. However, where practical, pressure tests of vessel components/sections can be performed in lieu of entire vessels (e.g., a new nozzle). An engineer should be consulted when a pressure test of vessel component/sections is to be performed to confirm it is suitable for the intended purpose.

5.8.3 Test Pressure Determination

5.8.3.1 When a code hydrostatic pressure test is required, the minimum test pressure should be in accordance with the rules of the applicable construction code. For this purpose, the minimum test pressure for vessels that have been rerated using the design allowable stress published in the 1999 addendum or later of ASME *BPVC*, *Section VIII, Division 1*, Code Case 2290, or Code Case 2278, is 130 % of MAWP and corrected for temperature. The minimum test pressure for vessels rerated using the design allowable stress of ASME *BPVC*, *Section VIII, Division 1*, published prior to the 1999 addendum, is 150 % of MAWP and corrected for temperature. The minimum test pressure for vessels designed using ASME *BPVC*, *Section VIII, Division 1* is as follows:

$$\text{Test pressure in psig (MPa)} = 1.5\ \text{MAWP} \times (S_{\text{test temp}}/S_{\text{design temp}}),\ \text{prior to 1999 addendum} \quad (1)$$

$$\text{Test pressure in psig (MPa)} = 1.3\ \text{MAWP} \times (S_{\text{test temp}}/S_{\text{design temp}}),\ \text{1999 addendum and later} \quad (2)$$

where

$S_{\text{test temp}}$ is the allowable stress at test temperature in ksi (MPa);

$S_{\text{design temp}}$ is the allowable stress at design temperature in ksi (MPa).

5.8.3.2 When a noncode-related pressure test (leak/tightness test) is performed after repairs, the test pressure may be conducted at pressures determined by the owner-operator. Tightness test pressures are determined by the owner-operator but are generally not for the purpose of proving strength of repairs.

5.8.4 Pressure Test Preparation

5.8.4.1 Before applying a pressure test, appropriate precautions and procedures should be taken to ensure the safety of personnel involved with the pressure test. This review is especially important for in-service pressure vessels that may have experienced metallurgical degradation or a cracking phenomenon. It is even more important for pneumatic pressure tests where the potential energy released could be very high. A close visual inspection of pressure vessel components shall not be performed until the vessel pressure is at or below the MAWP.

5.8.4.2 When a pressure test is to be conducted in which the test pressure will exceed the set pressure of the PRD(s), the PRD(s) should be removed. An alternative to removing the PRD(s) is to use test clamps to hold down the valve disks. Applying an additional load to the valve spring by turning the compression screw is prohibited. Other appurtenances, such as gauge glasses, pressure gauges, and rupture disks, that may be incapable of withstanding the test pressure should be removed or blanked off. When the pressure test has been completed, PRDs and appurtenances removed or made inoperable during the pressure test shall be reinstalled or reactivated.

5.8.5 Hydrostatic Pressure Tests

5.8.5.1 Before applying a hydrostatic test, the supporting structures and foundation design should be reviewed to determine they are suitable for the hydrostatic test load. All instruments and other components that might experience the full hydrostatic test pressure should be checked to determine they are designed for the specified pressure test; otherwise, they shall be blinded off from the test.

5.8.5.2 Hydrostatic pressure tests of equipment having components of Type 300 series stainless steel should be conducted with potable water, steam condensate, or other fluid having a chloride concentration of less than 50 ppm.

5.8.5.3 After the test, the vessel should be completely drained and dried. The inspector should verify the specified water quality is used and the vessel has been drained and dried (all high-point vents should be open during draining). If potable water is not available or if immediate draining and drying is not possible, water having a very low chloride level (e.g., steam condensate), higher pH (>10), and inhibitor addition should be considered to reduce the risk of pitting, chloride stress corrosion cracking, and microbiologically influenced corrosion (biocide). For sensitized austenitic stainless steel piping subject to polythionic stress corrosion cracking, the use of an alkaline-water solution for pressure testing should be considered (see NACE SP0170).

5.8.6 Pneumatic Pressure Tests

Pneumatic testing (including combined hydropneumatic) may be used when hydrostatic testing is impracticable because of limited supporting structure or foundation, refractory linings, or process reasons. When used, the potential personnel and property risks of pneumatic testing shall be considered by an engineer before conducting the test. As a minimum, the inspection precautions contained in the ASME *BPVC* shall be applied when performing any pneumatic test. A pneumatic test procedure should be developed by the engineer following the steps outlined in ASME PCC-2, Article 501.

5.8.7 Test Temperature and Brittle Fracture Considerations

5.8.7.1 At ambient temperatures, carbon, low-alloy, and other ferritic steels may be susceptible to brittle failure. A number of failures have been attributed to brittle fracture of steels that were exposed to temperatures below their transition temperature and to pressures greater than 20 % of the required hydrostatic test pressure. Most brittle fractures, however, have occurred on the first application of a high-stress level (the first hydrostatic or overload). The potential for a brittle failure shall be evaluated prior to hydrostatic or especially prior to pneumatic testing because of the higher potential energy involved. Special attention should be taken when testing:

a) low-alloy steels, especially 2 1/4 Cr-1Mo, because they may be prone to temper embrittlement, or

b) any other metal that may be prone to embrittlement per the damage mechanisms listed in API RP 571 or because of high triaxial stresses due to thickness or geometry considerations.

5.8.7.2 To minimize the risk of brittle fracture during a pressure test, the metal temperature should be maintained at least 17 °C (30 °F) above the MDMT or MAT for vessels more than 5 cm (2 in.) thick and 6 °C (10 °F) above the MDMT or MAT for vessels that have a thickness of 5 cm (2 in.) or less. The test temperature need not exceed 50 °C (120 °F) unless there is information on the brittle characteristics of the vessel material indicating a higher test temperature is needed.

5.8.7.3 When hydrotesting solid weld overlaid or clad austenitic stainless steel, the water temperature should not exceed 50 °C (120 °F) to avoid possible chloride stress corrosion cracking.

5.8.8 Pressure-testing Alternatives

5.8.8.1 Appropriate NDE (e.g., RT, UT, PT, and MT) shall be specified and conducted when a pressure test is not performed after a major repair or alteration. Substituting NDE procedures for a pressure test after an alteration or major repair may be done only after the engineer and inspector have approved. In such cases, it is advisable to conduct an FFS assessment to identify the critical flaw size(s) to specify the acceptance criteria for the specified NDE technique(s). Refer to ASME PCC-2, Article 502 for guidance on NDE in lieu of pressure testing for repairs and alterations.

5.8.8.2 For cases where manual UT is used to examine welds in lieu of pressure test, the owner-operator shall specify industry-qualified angle beam examiners. For use of UT in lieu of RT, ASME *BPVC* Case 2235 or ASME *BPVC Section VIII, Division 2*, 7.5.5 shall be followed.

5.9 Material Verification and Traceability

5.9.1 During repairs or alterations of pressure vessels, the inspector shall verify all new materials (including carbon steel as well as all alloys) are in compliance with the specifications. At the discretion of the owner-operator or the inspector, this assessment can be made by 100 % verification checking, 100 % positive material identification (PMI), or by sampling a percentage of the materials depending upon the criticality of each service. PMI testing can be done by the inspector or the examiner using suitable methods such as optical emission spectrographic analyzers or X-ray fluorescence analyzers. The inspector or examiner shall be trained and qualified to conduct the PMI testing. When using PMI to verify small amounts of alloy composition that are critical to corrosion resistance, precautions should be taken to determine the potential for inaccurate measurements associated with the particular PMI instrument under consideration. API RP 578 has additional guidance on material verification programs.

5.9.2 If a pressure vessel component experiences accelerated corrosion or should fail because an incorrect material was inadvertently substituted for the specified material, the inspector shall consider the need for further verification of existing materials in the pressure vessel or other pressure vessels in same or similar service. The extent of further verification will depend upon various factors including the consequences of failure and the probability of further material errors.

5.10 Inspection of In-service Welds

5.10.1 Inspection for weld quality is normally accomplished as a part of the requirements for new construction, repairs, or alterations. However, welds and weld heat-affected zones are often inspected for corrosion and/or service-induced cracking as part of the in-service inspections. When preferential weld corrosion or cracking is noted, additional welds of the pressure vessel should be examined to determine the extent of damage. API RP 577 provides additional guidance on weld inspection.

5.10.2 On occasion, profile radiography, density radiography, and UTs may reveal what appears to be a flaw in an existing weld. If crack-like flaws are detected while the pressure vessel is in operation, further inspection may be used to assess the magnitude of the flaw. Additionally, an effort should be made to determine whether the crack-like flaws are from original weld fabrication or caused by a service-related cracking mechanism.

5.10.3 Crack-like flaws, environmental cracking and preferential weld corrosion shall be assessed by the inspector and either an engineer or corrosion specialist (refer to API 579-1/ASME FFS-1).

5.10.4 Dissimilar metal welds (DMW) may be prone to cracking or preferential in-service corrosion and as such, the inspection plan should include techniques to identify cracking or corrosion damage at the DMWs when operating temperatures and/or service conditions indicate the need. API RP 572 provides additional guidance on DMW.

5.11 Inspection and Repair of Flanged Joints

5.11.1 Flanged joints should be examined for evidence of leakage, such as stains, deposits, or drips. Process leaks onto flange fasteners may result in corrosion or environmental cracking. This examination should include those flanges enclosed with flange or splash-and-spray guards. Flanged joints that have been clamped and pumped with sealant should be checked for leakage at the bolts. Fasteners subjected to such leakage may corrode or crack (e.g., caustic cracking). If repumping is being considered, UT of the bolts before repumping may be necessary to assess their integrity depending upon the process conditions to which they are exposed (refer to ASME PCC-2).

5.11.2 Accessible flange faces should be examined for distortion and to determine the condition of gasket-seating surfaces. Gasket-seating surfaces damaged and likely to result in a joint leak should be resurfaced prior to being placed back in service. Special attention should be provided to flange faces in high-temperature/high-pressure hydroprocessing services prone to gasket leaks during start-up and on-stream. If flanges are excessively bent or distorted, their markings and thicknesses should be checked against engineering requirements before taking corrective action. Refer to ASME PCC-1, Appendix D for guidance on flange face evaluation.

5.11.3 Flange fasteners should be examined visually for corrosion and thread engagement. Fasteners shall be fully engaged for the full depth of the nut on new and reassembled bolted joints. Fasteners not fully engaged on existing bolted joint assemblies may be considered acceptably engaged if the lack of complete engagement is not more than one thread. Refer to ASME PCC-1 for more details.

5.11.4 The markings on a representative sample of newly installed fasteners and gaskets should be examined to determine whether they meet the material specification. The markings are identified in the applicable ASME and ASTM standards. Questionable fasteners should be verified or renewed. If mismarked fasteners are located, they should be brought to the attention of those involved in QA/QC of the vendor/supplier for corrective action but may be used if the proper specification is verified and the markings corrected.

5.11.5 Flanges in high-pressure and/or high-temperatures services that have been boxed in or leaked on-stream during the previous operating run should receive special attention during inspection and maintenance outages to determine what corrective action is appropriate to avoid further leaks.

5.11.6 Guidance on the inspection and repair of flanged joints can be found in ASME PCC-2, Article 305. Additionally, ASME PCC-1, Appendix A provides guidance for establishing criteria for the training and qualifications of bolted joint assembly personnel. Such training and qualifications may help to reduce/avoid bolted flange joint leaks. Owner-operator should follow the guidance in this ASME PCC-1, Appendix A with their own training and qualification program or use an external organization providing such services. This appendix also provides guidance for the training, qualification, duties, and responsibilities for qualified bolting specialists and instructors engaged in the inspection and quality assurance of the assembly and disassembly of bolted joints.

5.12 Inspection of Shell and Tube Heat Exchangers

Refer to API RP 572 for more information on inspection of several types of heat exchangers and ASME PCC-2, Article 312 for guidance on the inspection and repair of shell and tube heat exchangers. Also refer to API RP 586 Part 1 for guidance on selecting heat exchanger tubular inspection techniques.

6 Interval/Frequency and Extent of Inspection

6.1 General

6.1.1 All pressure vessels and associated PRDs shall be inspected and tested at the intervals/frequencies provided in this section.

6.1.2 The appropriate inspection shall provide the information necessary to determine all of the essential sections or components of the equipment are safe to operate until the next scheduled inspection. The risks associated with operational shutdown and start-up and the possibility of increased corrosion due to exposure of vessel surfaces to air and moisture should be evaluated when an internal inspection is being planned.

6.2 Inspection During Installation and Service Changes

6.2.1 Vessel Installations

6.2.1.1 Pressure vessels shall be inspected by an inspector at the time of installation. The purpose of this inspection is to verify the equipment is safe for operation and that no unacceptable damage occurred during transportation to the installation site, and to initiate plant inspection records for the equipment. This inspection also provides an opportunity to collect desired baseline information and to obtain the initial thickness readings at designated CMLs. The installation inspection shall verify:

a) the nameplate information is correct per the manufacturer's data reports and design requirements;

b) the equipment is installed correctly, supports are adequate and secured, exterior equipment such as ladders and platforms are secured, insulation is properly installed and flanged, and other mechanical connections are properly assembled and the vessel is clean and dry;

c) PRDs satisfy design and installation requirements per the requirements in API PR 576.

If noncompliance is found or the requirements for the PRD are not met, document and recommend appropriate repairs or engineering assessment that may be necessary to confirm the vessel is fit for service and properly protected from over-pressure.

6.2.1.2 Internal field inspection of new vessels is not required, provided appropriate documentation (e.g., manufacturer's data reports and final shop inspection report) assures the vessels comply with the specified design and specification requirements.

6.2.2 Vessel Service Change

6.2.2.1 If the service conditions of a vessel are changed (e.g., process contents, maximum operating pressure, and the maximum and minimum operating temperature), the inspection intervals shall be established for the new service conditions.

6.2.2.2 If both the ownership and the location of a vessel are changed, the vessel shall be internally and externally inspected before it is reused. This inspection should include baseline examinations for any anticipated future examinations planned as a result of the new service (e.g., if the vessel is going into a service where stress corrosion cracking is a potential, then a baseline examination of weld cracking is advisable). Also, the allowable service conditions and the inspection interval shall be established for the new service. The inspector should also assure adequate documentation (process safety information) for the vessel is on file.

6.2.2.3 In some cases (e.g., movement to a new location of ASME *BPVC, Section VIII, Division 2* vessels), a reanalysis or review/revalidation of the user design specification may be required.

6.3 RBI

6.3.1 An RBI assessment, in compliance with API RP 580, may be used to establish the appropriate inspection intervals for internal, on-stream, and external inspections, as well as inspection and testing intervals for PRDs. The RBI assessment may allow previously established inspection intervals to be exceeded from limits specified in 6.4 and 6.5, including the 10-year inspection and one-half remaining life limits for internal and on-stream inspections and the 5-year inspection limit for the external inspections. RBI intervals on external inspections shall not exceed 10 years.

6.3.2 When an RBI interval for the internal or on-stream inspection exceeds the 10-year limit, the RBI assessment shall be reviewed and approved by the engineer and inspector at intervals not to exceed 10 years (or more often if warranted by process, equipment, or consequence changes).

6.3.3 When an RBI assessment is used to extend the internal or on-stream inspection interval, the assessment should include a review of the inspection history and potential fouling of the vessel's PRD(s).

6.4 External Inspection

6.4.1 Unless justified by an RBI assessment, each aboveground pressure vessel shall have a visual external inspection at an interval that does not exceed the lesser of five years or the required internal/on-stream inspection. It is preferred to perform this inspection while the vessel is in operation. The interval is established by the inspector or engineer in accordance with the owner-operator's QA system.

6.4.2 External inspection intervals for vessels in noncontinuous service are the same as for vessels in continuous service because the external environment does not change during noncontinuous service. For equipment abandoned-in-place, the owner-operator may need to conduct appropriate external inspections to make sure deterioration of insulation, vessel supports, and other appurtenances do not deteriorate to the point where they become a hazard to personnel or to any nearby in-service equipment.

6.5 Internal, On-stream, and Thickness Measurement Inspections

6.5.1 Inspection Interval

6.5.1.1 Unless justified by an RBI assessment, the period between internal or on-stream inspections shall not exceed one-half the remaining life of the vessel or 10 years, whichever is less. When the extent of thinning can be detected or effectively monitored externally, an internal inspection is not required at one-half the remaining life. Whenever the remaining life is less than four years, the inspection interval may be the full remaining life up to a maximum of two years. The interval is established by the inspector or engineer in accordance with the owner-operator's QA system. Refer to 6.5.2 for guidance on when an on-stream inspection may be used to satisfy (in-lieu of) an internal inspection requirement.

6.5.1.2 Unless justified by an RBI assessment, the period between thickness measurement inspections shall not exceed the lesser of one-half the remaining life of the vessel or 10 years. Whenever the remaining life is less than four years, the inspection interval may be the full remaining life up to a maximum of two years.

6.5.1.3 Due to changes in operating characteristics of some process units, corrosion rates in certain sections of the unit sometimes accelerate or become unstable for various reasons. When that happens, an investigation consistent with the principles documented in API RP 585 should be implemented to determine the cause of the change. Additionally, the operations group should alert those responsible for monitoring mechanical integrity (inspection and corrosion SMEs) so that inspection plans and/or frequency of inspections can be adjusted as necessary. However, when it is determined that the operating conditions are not easily controllable or cannot be readily changed to bring corrosion rates back under control, it sometimes results in extended periods of time when shortened inspection frequencies become the primary means of controlling the risk of a loss of containment (LOC). The owner-operator is advised to be aware that frequent inspections could be a higher risk integrity strategy than replacement, redesign, or upgrading the materials of construction to be more resistant to the fluids contained. Under some circumstances, permanently mounted sensors, which can be continuously monitored, may also be more appropriate than manual frequent inspections.

6.5.1.4 For pressure vessels in noncontinuous service, the interval is based on the number of years of actual service (vessel in operation) instead of calendar years, provided that when idled, the vessel is:

a) isolated from the process fluids, and

b) not exposed to corrosive internal environments (e.g., inert gas purged or filled with noncorrosive hydrocarbons). Vessels in noncontinuous service and not adequately protected from corrosive environments may experience increased internal corrosion while idle. The corrosion rates should be carefully reviewed before setting the internal or on-stream intervals.

6.5.1.5 An alternative method to establish the required inspection interval is by calculating the projected MAWP of each vessel component as described in 7.3. This procedure may be iterative, involving selection of an inspection interval, determination of the corrosion loss expected over the interval, and calculation of the projected MAWP. The inspection interval is within the maximum permitted as long as the projected MAWP of the limiting component is not less than the lower of the nameplate or rerated MAWP plus applicable static head pressure. Unless an RBI assessment is performed, the maximum inspection interval using this method is also 10 years.

6.5.1.6 Vessels may be exempt from the internal inspection and corrosion monitoring designated in this section provided a qualified corrosion subject matter expert (SME) documents that there are no credible internal degradation mechanisms. Vessels by their design that cannot be satisfactorily inspected either internally or on-stream for credible degradation mechanisms (e.g., aluminum core exchanger) shall have appropriate analysis, monitoring, and maintenance strategies to manage the risk of failure. External inspections are still required for both types of equipment.

6.5.2 On-stream Inspection in Lieu of Internal Inspections

6.5.2.1 At the discretion of the inspector, an on-stream inspection may be substituted for the internal inspection in the following situations:

a) when size or configuration makes vessel entry for internal inspection physically impossible;

b) when vessel entry for internal inspection is physically possible and all of the following conditions are met:

   1) the general corrosion rate of a vessel is known to be less than 0.125 mm (0.005 in.) per year;

   2) the vessel remaining life is greater than 10 years;

   3) the corrosive character of the contents, including the effect of trace components, has been established by at least five years of the same or similar service;

   4) no questionable condition is discovered during the external inspection;

   5) the operating temperature of the steel vessel shell does not exceed the lower temperature limits for the creep rupture range of the vessel material referenced in API 579-1/ASME FFS-1;

   6) the vessel is not subject to environmental cracking or hydrogen damage from the fluid being handled;

   7) the vessel does not have a nonintegrally bonded liner such as strip lining or plate lining.

6.5.2.2 If the requirements of 6.5.2.1 b) are not met, the next inspection shall be an internal inspection. As an alternate to the above limits, an on-stream inspection can be performed if an RBI assessment (per 6.3) determines risk associated with the vessel is acceptable to the owner-operator and the effectiveness of the external NDE technique(s) is adequate for the expected damage mechanism. This assessment should include a review of past process conditions and likely future process conditions.

6.5.2.3 When an on-stream inspection is conducted, the type and extent of NDE shall be specified in the inspection plan. This could include ultrasonic thickness measurements, radiography, or other appropriate means of NDE to measure metal thicknesses and/or assess the integrity of the pressure boundary (e.g., vessel wall and welds). When an on-stream inspection is conducted, the inspector shall have sufficient access to all parts of the vessel (heads, shell, and nozzles) so an accurate assessment of the vessel condition can be made.

6.5.3 Same and Similar Service Equipment

When a vessel has been internally inspected, the results of that inspection can be used to determine whether an on-stream inspection can be substituted for an internal inspection on a similar pressure vessel operating within the same or similar service and conditions.

The inspection of one vessel (preferably the worst case) may be taken as representative of the whole train when the following conditions are observed:

a) two or more pressure vessels are installed in series and no potentially corrosive contaminants are introduced at an intermediate point in the train or otherwise become present that could potentially affect the vessel integrity;

b) the operating conditions in any part of the train are the same;

c) sufficient corrosion history has been accumulated.

Risk assessment or RBI analysis may be useful when considering the extent of same service applicability in determining internal and on-stream inspection requirements based on comparing one pressure vessel to other pressure vessels and the number of pressure vessels to be inspected within a grouping.

However, if the vessel is subject to environmental cracking or hydrogen damage, the results of an internal inspection on a similar service pressure vessel cannot be used to substitute an on-stream inspection for an internal inspection.

6.5.4 Multizone Vessels

For a large vessel with two or more zones of differing corrosion rates, each zone may be treated independently when determining the inspection intervals or for substituting the internal inspection with an on-stream inspection. Each zone shall be inspected based on the interval for that zone.

6.6 Pressure-relieving Devices

6.6.1 General

PRDs shall be tested and repaired by a repair organization qualified and experienced in relief valve maintenance per definitions in 3.1.71. PRDs shall be inspected, tested, and maintained in accordance with API RP 576 and API 510.

6.6.2 Quality Assurance (QA) Process

6.6.2.1 Each PRV repair organization shall have a fully documented QA system. As a minimum, the following shall be included in the QA manual:

a) title page;

b) revision log;

c) contents page;

d) statement of authority and responsibility;

e) organizational chart;

f) scope of work;

g) drawings and specification controls;

h) requirements for material and part control;

i) repair and inspection program;

j) requirements for welding, NDE, and heat treatment;

k) requirements for valve testing, setting, leak testing, and sealing;

l) general example of the valve repair nameplate;

m) requirements for calibrating measurement and test gauges;

n) requirements for updating and controlling copies of the QC manual;

o) sample forms;

p) training and qualifications required for repair personnel;

q) requirements for handling of nonconformances;

r) requirements for shop auditing for adherence to the QA process.

6.6.2.2 Each repair organization shall have a documented training program that shall verify that repair personnel are qualified within the scope of the repairs they will be conducting.

6.6.3 Testing and Inspection Intervals

6.6.3.1 PRDs shall be tested and inspected at intervals frequent enough to verify the devices perform reliably in the particular service conditions. Other PRDs (e.g., rupture disks and vacuum-breaker valves) shall be inspected at intervals based on service conditions. The inspection interval for all PRDs is determined by the inspector, engineer, or other qualified individual per the owner-operator's QA system.

6.6.3.2 Unless documented experience and/or an RBI assessment indicates a longer interval is acceptable, test and inspection intervals for PRDs in typical process services should not exceed:

a) five years for typical process services, and

b) 10 years for clean (nonfouling) and noncorrosive services.

6.6.3.3 Wherever possible, as-received pop testing should be conducted prior to cleaning in order to yield accurate as-received pop testing results that will help establish the appropriate inspection and servicing interval. Cleaning of deposits prior to as-received pop testing can remove deposits that would have prevented the valve from opening at set pressure. Refer to API RP 576 for more information on as-received pop-testing.

6.6.3.4 When a PRD is found to be heavily fouled or stuck shut or when a PRD fails an as received pop test, the inspection and testing interval shall be reevaluated to determine if the interval should be shortened or other corrective action taken. An investigation consistent with the principles documented in API 585 should be undertaken to determine the cause of the fouling or the reasons for the PRD not operating properly. Refer to API RP 576 "'As-received'" Pop Test Results" for additional information on PRD pop test results and investigations.

6.6.3.5 After maintenance of the valve(s) is completed and the valve(s) is reinstalled, a full visual on-stream inspection shall be performed by the inspector or designee before startup per API RP 576. This provides a critical check that the proper relief device is in the proper location, installed properly, and has the proper set pressure for the intended service.

6.7 Deferral of Inspections, Tests, and Examinations

6.7.1 General

Pressure vessels or PRDs operated beyond the due date without a valid deferral in accordance with these requirements is not permitted by this code. Deferrals should be the occasional exception, not a frequent occurrence. All deferrals shall be documented. Pressure vessels or PRDs which were granted a deferral can be operated to the new due date without being considered overdue for the deferred inspections, tests, or examinations.

Inspections, tests, or examinations for pressure vessels and associated PRDs that cannot be completed by their due date may be deferred for a specified period, subject to the requirements in the following subsections.

6.7.2 Simplified Deferral

A simplified short-term deferral may be approved by the owner-operator if ***all*** of the following conditions are met.

a) The current due date for the inspection, test, or examination has not been previously deferred.

b) The proposed new due date would not increase the current inspection/servicing interval or due date by more than 10 % or six months, whichever is less.

c) A review of the current operating conditions as well as the pressure vessel or PRD history has been completed with results that support a short-term/one-time deferral.

d) The deferral request has the consent of the inspector representing or employed by the owner-operator and an appropriate operations management representative(s).

e) Updates to the pressure vessel or PRD records with deferral documentation are complete before it is operated beyond the original due date.

6.7.3 Deferral

Deferral requests not meeting the conditions of a simplified deferral above shall follow a documented deferral procedure/process that includes all of the following minimum requirements:

a) Perform a documented risk-assessment or update an existing RBI assessment to determine if the proposed deferral date would increase risk above acceptable risk threshold levels as defined by the owner-operator. The risk assessment may include any of the following elements as deemed necessary by the owner-operator:

   1) FFS analysis results;

   2) consequence of failure;

   3) applicable damage mechanism susceptibilities and rates of degradation;

   4) calculated remaining life;

5) historical conditions/findings from inspections, tests, and examinations and their technical significance;

6) extent and/or probability of detection (i.e., effectiveness) of previous inspections, tests, or examinations as well as the amount of time that has elapsed since they were last performed;

7) considerations for any previous changes to inspection or test intervals (e.g., reductions in interval due to deteriorating conditions);

8) disposition(s) of any previous requests for deferral on the same pressure vessel or pressure-relieving device;

9) historical conditions/findings for pressure vessels or pressure-relieving devices in similar service if available;

b) Determine if the deferral requires the implementation of, or modification to, existing IOWs or operating process control limits;

c) Review the current inspection plan to determine if modifications are needed to support the deferral;

d) Obtain the consent and approval of appropriate pressure vessel personnel including the inspector representing or employed by the owner-operator and appropriate operations management representative(s);

e) Updates to the pressure vessel or PRD records with deferral documentation are complete before it is operated beyond the original due date.

6.8 Deferral of Inspection Repair Recommendation Due Dates

Inspection repair recommendations that cannot be completed by their due date can be deferred for a specific period of time, if appropriate, by a documented change in date of required completion. The deferral of the due date shall be documented in the inspection records and shall have the concurrence with the appropriate pressure equipment inspection personnel including the inspector and the inspection supervisor. Inspection recommendations that have not been completed by the required due date without a documented and approved change of date are not permitted by this code and are considered overdue for completion. The deferral of inspection recommendations should be the occasional exception not a frequent occurrence. Equipment shall remain within the limits of the minimum required thickness as determined in this code or by other engineering evaluation during the period of deferral.

6.9 Review of Inspection Repair Recommendations

Inspector recommendations can be changed or deleted after review by pressure vessel engineer or inspection supervision. If inspector recommendations are changed or deleted, inspection records shall record the reasoning, date of change/deletion, and name of person who did the review.

7 Inspection Data Evaluation, Analysis, and Recording

7.1 Corrosion Rate Determination

7.1.1 Existing Pressure Vessels

7.1.1.1 Corrosion rate for thinning damage mechanisms is determined by the difference between two thickness readings divided by the time interval between the readings. The determination of corrosion rate may include thickness data collected at more than two different times. Short-term corrosion rates are typically determined by the two most recent thickness readings, whereas long-term rates use the most recent reading and one taken earlier in the life of the equipment. These different rates help identify recent corrosion issues from those acting over the long term. The long-term (LT) corrosion rate shall be calculated from the following formula:

$$\text{Corrosion rate (LT)} = \frac{t_{\text{initial}} - t_{\text{initial}}}{\text{time between } t_{\text{initial}} \text{ and } t_{\text{actual}} \text{(years)}} \tag{3}$$

The short-term (ST) corrosion rate shall be calculated from the following formula:

$$\text{Corrosion rate (ST)} = \frac{t_{\text{previous}} - t_{\text{actual}}}{\text{time between } t_{\text{previous}} \text{ and } t_{\text{actual}} \text{(years)}} \tag{4}$$

where

t_{initial} is the initial thickness at the same CML as t_{actual}. It is either the first thickness measurement at this CML or the thickness at the start of a new corrosion rate environment, in mm (in.);

t_{actual} is the actual thickness of a CML, in mm (in.), measured during the most recent inspection;

t_{previous} is the previous thickness measured during the prior inspection. It is at the same location as t_{actual} measured during a previous inspection, in mm (in.).

7.1.1.2 When evaluating corrosion rates as part of the data assessment, the inspector, in consultation with a corrosion specialist, shall select the corrosion rate that best reflects the current conditions. The following should be considered when evaluating what corrosion rate should be used in a corroded area for calculating remaining life and the next inspection due date:

a) whether the corrosion damage mechanism is general or localized;

b) areas subject to fluid impingement, erosive fluid, or erosive-corrosive conditions;

c) estimated time of initiation of the corrosion problem (if not from initial operation) as a basis for measuring wall loss and appropriate time interval for determining the corrosion rate;

d) the potential point where process change(s) occurred that may have caused the corrosion (such as water wetting, chlorides entering the process, or lower pH);

e) the effect of scale formation to either protect the component from corrosion or the loss of that protection (such as higher fluid velocity stripping the protective scale away from the vessel wall);

f) the potential for accelerated corrosion in stagnant areas (such as where iron sulfide might accumulate);

g) continuing operation within the IOW;

h) whether the short-term rate was due to an episodic event and whether or not the issue that caused the event has been corrected.

7.1.2 Newly Installed Pressure Vessels or Changes in Service

For a new vessel or for a vessel for which service conditions are being changed, one of the following methods shall be used to determine the vessel's probable corrosion rate. The remaining life and inspection interval can be estimated from this rate.

a) A corrosion rate may be calculated from data collected by the owner-operator on vessels operating in the same or similar service.

b) A corrosion rate may be determined through appropriately placed ultrasonic sensors on the equipment.

c) A corrosion rate may be estimated by a corrosion specialist.

d) A corrosion rate may be estimated from published data on vessels in same or similar service.

In a case where items listed a) through d) cannot be applied with confidence and to ensure that an unexpected accelerated corrosion rate does not occur unidentified, the inspection plan shall include determining wall loss change rate on-stream by direct measurement techniques after six months of service. Because of potential measure error, this may not determine an actual corrosion rate, but ensures data is available to direct the inspection plan until a corrosion rate can be established. This is provided as a cautionary guideline due to the statistical variation in thickness readings taken in short interval, which may suggest a corrosion rate that is not truly indicative of the environment.

Subsequent determinations shall be made at appropriate intervals until a credible corrosion rate is established. If it is later determined that an inaccurate corrosion rate was assumed, the corrosion rate in the remaining life calculations shall be changed to the actual corrosion rate.

7.2 Remaining Life Calculations

7.2.1 The remaining life of the vessel (in years) shall be calculated from the following formula:

$$\text{Remaining life} = \frac{t_{\text{actual}} - t_{\text{required}}}{\text{corrosion rate}} \tag{5}$$

where

t_{actual} is the actual thickness of a CML, in mm (in.), measured during the most recent inspection;

t_{required} is the required thickness at the same CML or component, in mm (in.), as the t_{actual} measurement. It is computed by the design formulas (e.g., pressure and structural) and does not include corrosion allowance or manufacturer's tolerances.

7.2.2 A statistical analysis may be used in the corrosion rate and remaining life calculations for the pressure vessel sections. This statistical approach may be applied for assessment of substituting an internal inspection (see 6.5.2.1 b) or for determining the internal inspection interval. Care should be taken to determine the statistical treatment of data results reflects the actual condition of the vessel section, especially those subject to localized corrosion. Statistical analysis may not be applicable to vessels with random but significant localized corrosion. The analysis method shall be documented.

7.2.3 Remaining life calculations have a significant impact on the efficiency and effectiveness of the inspection and maintenance process. The corrosion rate and thickness data used in remaining life calculations should be validated, as they are the data that is to be used to determine next inspection dates. Bad data can lead to increased likelihood of unanticipated equipment failure or premature retirement of vessels (see API RP 572).

7.3 Maximum Allowable Working Pressure (MAWP) Determination

7.3.1 The MAWP for the continued use of a pressure vessel shall be based on computations determined using the applicable construction code. The resulting MAWP from these computations shall not be greater than the original MAWP, unless a rerating is performed in accordance with 8.8.

7.3.2 Computations may be made only if the following essential details comply with the applicable requirements of the code being used: head, shell, and nozzle reinforcement designs; material specifications; allowable stresses; weld joint efficiencies; inspection acceptance criteria; and cyclical service requirements.

7.3.3 The wall thickness used in these computations shall be the actual thickness as determined by inspection (see 5.6.2) minus twice the estimated corrosion loss before the date of the next inspection, as defined by:

$$t = t_{\text{actual}} - 2(C_{\text{rate}} \times I_{\text{internal}}) \tag{6}$$

where

C_{rate} is the governing corrosion rate in mm (in.) per year;

$I_{internal}$ is the interval of the next internal or on-stream inspection in years;

t_{actual} is the actual thickness of a CML, in mm (in.), measured during the most recent inspection.

7.3.4 Multiple thickness measurements shall be taken when the actual thickness determined by inspection of the component is greater or lesser than the thickness reported in the material test report or the manufacturer's data report, especially if the component was made by a forming process. The thickness measurement procedure shall be approved by the inspector. Allowance shall be made for other loads in accordance with the applicable provisions of the ASME *BPVC*.

7.4 Analysis of Corroded Regions

7.4.1 General

This section outlines methodologies that can be used when a vessel thickness is below the required thickness.

7.4.2 Evaluation of Locally Corroded Areas

For locally corroded areas, refer to API 579-1/ ASME FFS-1, which provides assessment methodology.

7.4.3 Evaluation of Pitting

During the current inspection, widely scattered pits may be ignored as long as all of the following are true:

a) the remaining thickness below the pit is greater than one-half the required thickness (½ $t_{required}$), and greater than 1.6 mm (0.062 in.);

b) the total area of the pitting deeper than the corrosion allowance does not exceed 45 cm^2 (7 $in.^2$) within any 20 cm (8 in.) diameter circle;

c) the sum of the pit diameters whose depths exceed the corrosion allowance along any straight 20 cm (8 in.) line does not exceed 5 cm (2 in.).

API 579-1/ASME FFS-1 may be used to evaluate different pit growth modes, estimate pitting propagation rates, and evaluate the potential problems with pitting remediation vs component replacement. The maximum pit depth and the extent of pitting are related in the API 579-1/ASME FFS-1, Level 1 assessment pitting charts, which may be used to evaluate the extent of pitting allowed before the next inspection.

7.4.4 Alternative Evaluation Methods for Thinning

An alternative to the procedures in 7.4.2 and 7.4.3, general metal loss may be evaluated following API 579-1/ ASME FFS-1 and local metal loss may be evaluated following API 579-1/ASME FFS-1. Where a FFS Level 3 analysis is necessary, refer to API 579-1/ASME FFS-1.

7.4.5 Joint Efficiency Adjustments

When the vessel surface away from a weld is corroded and the joint efficiency is less than 1.0, an independent calculation using the appropriate weld joint factor (typically 1.0) can be made. For this calculation, the surface at a weld includes 2.5 cm (1 in.) on either side of the weld (measured from the toe) or twice the required thickness on either side of the weld, whichever is greater.

7.4.6 Corroded Areas in Vessel Heads

7.4.6.1 The required thickness at corroded areas of ellipsoidal and torispherical heads can be determined as follows.

a) In the knuckle region of the head, use the appropriate head formula in the construction code.

b) In the central portion of the head, use the hemispherical head formula in the construction code. The central portion of the head is defined as the center of the head with a diameter equal to 80 % of the shell diameter.

7.4.6.2 For torispherical heads, the radius to use in the hemispherical head formula is the crown radius (equal to the outside diameter of the shell for standard torispherical heads, though other radii have been permitted).

7.4.6.3 For ellipsoidal heads, the radius to use in the hemispherical head formula shall be the equivalent spherical radius $K_1 \times D$, where D is the shell diameter (equal to the inside diameter) and K_1 is provided in Table 1. In Table 1, h is one-half the length of the minor axis (equal to the inside depth of the ellipsoidal head measured from the tangent line). For many ellipsoidal heads, $D/2h = 2.0$.

Table 1—Values of Spherical Radius Factor K_1

$D/2h$	K_1
3.0	1.36
2.8	1.27
2.6	1.18
2.4	1.08
2.2	0.99
2.0	0.90
1.8	0.81
1.6	0.73
1.4	0.65
1.2	0.57
1.0	0.50

NOTE The equivalent spherical radius equals K_1D; the axis ratio equals $D/2h$. Interpolation is permitted for intermediate values.

7.5 FFS Evaluations

Pressure-containing components found to have damage that could affect their load carrying capability (pressure loads and other applicable loads, e.g., weight and wind, per API 579-1/ASME FFS-1) shall be evaluated for continued service. FFS evaluations, such as those documented in API 579-1/ASME FFS-1, may be used for this evaluation and applicable to the specific damage observed. The following techniques may be used as an alternative to the evaluation techniques in 7.4.

a) To evaluate metal loss in excess of the corrosion allowance, an FFS assessment may be performed in accordance with API 579-1/ASME FFS-1 as applicable. This assessment requires the use of a future corrosion allowance, which shall be established based on Section 6 of this inspection code. These methods may also be used to evaluate blend ground areas where defects have been removed. It is important to verify there are no sharp corners in blend ground areas to minimize stress concentration effects.

b) To evaluate blisters, HIC/SOHIC damage, and laminations, an FFS assessment should be performed in accordance with API 579-1/ASME FFS-1, respectively. In some cases, this evaluation will require the use of a future corrosion allowance, which shall be established based on Section 6 of this inspection code.

c) To evaluate weld misalignment and shell distortions, an FFS assessment should be performed in accordance with API 579-1/ASME FFS-1.

d) To evaluate crack-like flaws, an FFS assessment should be performed in accordance with API 579-1/ASME FFS-1. When angle beam ultrasonic techniques are employed to size flaws, an industry-qualified UT angle beam examiner shall be used.

e) To evaluate potential creep damage on components operating in the creep regime, an FFS assessment should be performed in accordance with API 579-1/ASME FFS-1.

f) To evaluate the effects of fire damage, an FFS assessment should be performed in accordance with API 579-1/ ASME FFS-1.

g) To evaluate dent and gouge damage on components, an FFS assessment should be performed in accordance with API 579-1/ASME FFS-1.

h) To evaluate fatigue damage on components, an FFS assessment should be performed in accordance with API 579-1 / ASME FFS-1.

7.6 Required Thickness Determination

The required thickness shall be based on pressure, mechanical, and structural considerations using the appropriate design formulae and code allowable stress. For services with high potential consequences if failure were to occur, the engineer should consider increasing the required thickness above the calculated minimum thickness to provide for unanticipated or unknown loadings, undiscovered metal loss, or resistance to normal abuse.

7.7 Evaluation of Existing Equipment with Minimal Documentation

For pressure vessels that have no nameplate and minimal or no design and construction documentation, the following steps may be used to verify operating integrity.

1) Perform inspection to determine condition of the vessel, including a complete dimensional checking of all components necessary to determine the minimum required thickness and adequacy of the design of the vessel, e.g., heads, shell(s), transitions, openings, reinforcement pads, and saddle supports.

2) Define design parameters and prepare drawings.

3) Perform design calculations based on applicable construction codes and standards.

   a) Material—See ASME *BPVC, Section VIII, Division 1*, Paragraph UG-10(c) for guidance on evaluation of unidentified materials. If UG-10(c) is not followed, then for carbon steels, use allowable stresses for SA-283 Grade C and for alloy and nonferrous materials, use X-ray fluorescence analysis to determine material type on which to base allowable stress values.

   b) Allowable Stress—Do not use allowable stress values of the current ASME *BPVC* for vessels designed to an edition or addendum of the ASME *BPVC* due to the change in design factor used to establish allowable stress values. A reasonable assumption of year of construction should be made to determine the ASME *BPVC* edition to obtain an allowable stress value. Table 2 provides a reference to the change in design margin with respect to time.

   c) Joint Efficiency—When the extent of radiography originally performed is not known, use joint efficiency of 0.7 for Type No. (1) and 0.65 for Type No. (2) butt welds and 0.85 for seamless shells, heads, and nozzles or consider performing radiography if a higher joint efficiency is needed. (Recognize that performing radiography on welds in a vessel with minimal or no design and construction documentation may result in the need for an FFS evaluation and significant repairs.)

4) Attach a nameplate or stamping showing the MAWP and temperature, MAT, and date.

5) Perform pressure test as soon as practical, as required by code of construction used for design calculations.

Table 2—Change in Design Margin with Construction Code

Construction Code	Design Margin
ASME Section VIII, Div. 1, pre-1950	5.0
ASME Section VIII, Div. 1, 1950–1998	4.0
ASME Section VIII, Div. 1, 1999 and later	3.5
ASME Section VIII, Div. 2, pre-2007	3.0
ASME Section VIII, Div. 2, 2007 and later	2.4

7.8 Reports and Records

7.8.1 Pressure vessel owners-operators shall maintain permanent and progressive records of their pressure vessels and PRDs. Permanent records will be maintained throughout the service life of each equipment item; progressive records will be regularly updated to include new information pertinent to the inspection and maintenance history of the vessel and pressure relief devices, as well as operating information that may affect equipment integrity.

7.8.2 Pressure vessel and PRD records shall contain four types of information pertinent to mechanical integrity. Those four types and some examples of useful records in each include the following:

a) Construction and Design Information—For example, equipment serial number or other identifier, manufacturer's data reports, fabrication drawings, U-1 or other construction certification forms, nameplate photos/rubbings, heat treatment charts, design specification data, vessel design calculations, PRD sizing calculations, and construction drawings.

b) Inspection History—For example, inspection reports and data for each type of inspection conducted (e.g. internal, external, thickness measurements) and inspection recommendations for repair inspection reports shall document the date of each inspection and/or examination, the date of the next scheduled inspection, the name of the person who performed the inspection and/or examination, the serial number or other identifier of the equipment inspected, a description of the inspection and/or examination performed, and the results of the inspection and/or examination. Pressure vessel RBI records should be in accordance with API RP 580. The records should also indicate the disposition of each inspection recommendation, including the reason why an inspection recommendation was not implemented.

c) Repair, alteration, and rerating information—For example:

   1) repair and alteration forms like that shown in Annex D;

   2) reports indicating equipment still in service with either identified deficiencies, temporary repairs, or recommendations for repair are suitable for continued service until repairs can be completed;

   3) rerating documentation (including rerating calculations, new design conditions, and evidence of stamping).

d) FFS assessment documentation requirements are described in API 579-1/ASME FFS-1, Part 2.8. Specific documentation requirements for the type of flaw being assessed are provided in the appropriate part of API 579-1/ ASME FFS-1.

7.8.3 Site operating and maintenance records, such as operating conditions, including process upsets that may affect mechanical integrity, and mechanical damage from maintenance should also be available to the inspector. Refer to API RP 572 for example inspection recordkeeping forms.

7.8.4 Documented results of the inspection shall be approved by the responsible owner-operator inspector, engineer, or qualified designee and should be posted into the appropriate inspection data management system within 90 days of the completion of the inspection and/or startup.

8 Repairs, Alterations, and Rerating of Pressure Vessels and Pressure-relieving Devices

8.1 Repairs and Alterations

8.1.1 General

All repairs and alterations to pressure vessels shall be performed by a repair organization in accordance with the applicable principles of the ASME *BPVC* or the applicable construction or repair code and the equipment specific repair plan prepared by the inspector or engineer. Repairs to PRDs should be in accordance with API RP 576 and the approved relief valve QA manual. The repair organization shall follow all applicable safety requirements as designated in 5.3.

8.1.2 Authorization of Repair and Alteration

All repair and alteration work shall be authorized by the inspector before the work is started by a repair organization. Authorization for alterations to any pressure vessels and for repairs to pressure vessels that comply with ASME *BPVC, Section VIII, Division 2* may not be initiated until an engineer has also authorized the work. The inspector will designate the hold points required for repairs and alterations. The inspector may give prior general authorization for limited or routine repairs on a specific vessel provided the inspector is satisfied with the competency of the repair organization and the repairs are the kind that will not require a pressure test, e.g., weld overlay of corrosion on a vessel that does not require postweld heat treatment (PWHT).

8.1.2.1 Before any repairs are performed, all proposed methods of design, execution, materials, welding procedures, NDE, and testing shall be approved by the inspector or engineer. For alterations, major repairs, and temporary repairs, approval by both the inspector and engineer is required. The inspector may establish hold points to be implemented during the work execution.

8.1.2.2 The inspector shall approve all specified repair and alteration work at designated hold points and after completion of the work in accordance with the repair plan.

8.1.3 Design

New vessel nozzles, connections, or replacement parts shall meet the design requirements of the applicable construction code. The design of replacement parts and new nozzles shall employ the same allowable stress criteria as used for the vessel design. Design, location, and method of attachment shall comply with requirements of the applicable construction code. When damage to parts of a vessel is so great that repairs cannot restore them to design requirements, the parts shall be replaced. An engineer shall approve all nozzle installations.

8.1.4 Material

The material used in making repairs or alterations shall conform to the applicable construction code. Material markings, material control practices, and material test reports provided to owner-operator shall comply with the applicable construction code. Materials used for welded repairs and alterations shall be of known weldable quality and be compatible with the original material. Carbon or alloy steel with carbon content over 0.35 % shall not be welded, and carbon steel with carbon contents over 0.30 % may need special attention and preheating to avoid weld cracking. If the inspector believes there is any question about material verification documents, PMI should be specified.

8.1.5 Defect Repairs

Repairs to defects found in pressure vessel components may be made by several techniques often dependent upon the size and nature of the defect, the materials of construction, and the design requirements of the pressure vessel. Refer to ASME PCC-2, Article 304 for guidance on flaw excavation and weld repair. Repair techniques can be classified as permanent or temporary, depending upon their design and conformance to the applicable construction code.

8.2 Temporary Repairs

8.2.1 General

Temporary repairs may be conducted on pressure vessels as long as the inspector and engineer are satisfied the repair will render the vessel fit for continued service until permanent repairs can be conducted. Temporary repairs should be removed and replaced with suitable permanent repairs at the next available maintenance opportunity. Temporary repairs may remain in place for a longer period of time only if evaluated, approved, and documented by the engineer and inspector. Documentation of temporary repairs should include:

a) location of the temporary repair;

b) specific details about the repair (e.g., material of construction, thickness, size of welds, NDE performed);

c) details of analyses performed, including engineering calculations demonstrating the vessel is fit for service until permanent repairs or replacement is completed;

d) requirements for future inspections;

e) due date for installing permanent repair.

The inspection plans shall include monitoring the integrity of the temporary repair until permanent repairs are complete. Refer to ASME PCC-2, Article 204 and Article 306 for guidance on welded leak box and mechanical clamp repairs.

8.2.2 Fillet-welded Patches

8.2.2.1 Fillet-welded patches may be used to make temporary repairs to damaged, corroded, or eroded areas of pressure vessel components. Cracks shall not be repaired in this manner unless the engineer determines the cracks will not be expected to propagate from under the patch. In some cases, the engineer may need to perform an FFS analysis. Temporary repairs using fillet-welded patches shall be approved by an inspector and engineer.

8.2.2.2 Fillet-welded patches require special design consideration, especially related to welded joint efficiency.

a) Fillet-welded patches may be applied to the internal or external surfaces of shells, heads, and headers. They would preferably be applied on the external surface to facilitate on-stream examination.

b) The fillet-welded patches are designed to absorb the membrane strain of the parts so that in accordance with the rules of the applicable construction code, the following result:

    1) The allowable membrane stress is not exceeded in the vessel parts or the patches.

    2) The strain in the patches does not result in fillet-weld stresses that exceed allowable stresses for such welds.

    Exceptions to this requirement shall be justified with an appropriate FFS analysis.

c) ASME PCC-2, Article 212 may be used for designing a fillet-welded patch.

8.2.2.3 A fillet-welded patch shall not be installed on top of an existing fillet-welded patch except as additional opening reinforcement, if permitted by the applicable construction code. When installing a fillet-welded patch adjacent to an existing fillet-welded patch, the distance between the toes of the fillet weld shall not be less than:

$$d = 4\sqrt{Rt} \tag{7}$$

where

d is the minimum distance between toes of fillet welds of adjacent fillet weld attachments, in mm (in.);

R is the inside radius of the vessel, in mm (in.);

t is the actual thickness of the underlying vessel wall, in mm (in.).

Exceptions to this requirement in some low-consequence environments (e.g., low-pressure catalyst erosion services) shall be justified by an appropriate combination of FFS and risk analyses.

8.2.2.4 Fillet-welded patch plates shall have rounded corners with a minimum radius of 25 mm (1 in.) minimum radius.

8.2.3 Lap Band Repairs

A full encirclement lap band repair may be considered if the following requirements are met.

a) The design is approved and documented by the engineer and inspector.

b) Cracks shall not be repaired in this manner unless the engineer determines the cracks will not be expected to propagate from under the lap band. In some cases, the engineer may need to perform an FFS analysis.

c) The band is designed to contain the full vessel design pressure.

d) All longitudinal seams in the repair band are full-penetration butt welds with the design joint efficiency and inspection consistent with the appropriate code.

e) The circumferential fillet welds attaching the band to the vessel shell are designed to transfer the full longitudinal load in the vessel shell, using a joint efficiency of 0.45. Where significant, the eccentricity effects of the band relative to the original shell shall be considered in sizing the band attachment welds.

f) Appropriate surface NDE shall be conducted on all attachment welds.

g) Fatigue of the attachment welds, such as fatigue resulting from differential expansion of the band relative to the vessel shell, should be considered, if applicable.

h) The band material and weld metal are suitable for contact with the contained fluid at the design conditions and an appropriate corrosion allowance is provided in the band.

i) The damage mechanism leading to the need for repair shall be considered in determining the need for any additional monitoring and future inspection of the repair.

See ASME PCC-2, Article 206 on full encirclement sleeves for vessel nozzles.

8.2.4 Nonpenetrating Nozzles

Nonpenetrating nozzles (including pipe caps attached as nozzles) may be used to make temporary repairs to damaged pressure vessel components. The design and reinforcement of such nozzles shall consider the loss of the original shell material enclosed by the nozzle. The nozzle material shall be suitable for contact with the contained fluid at the design conditions and an appropriate corrosion allowance shall be provided. The damage mechanism leading to the need for repair shall be considered in determining the need for any additional monitoring and future inspection of the repair. Nonpenetrating nozzles may be used as permanent repairs of damage other than cracks when the design and method of attachment comply with the applicable construction code.

8.2.5 Nonmetallic Composite Wrap

Temporary repairs of pressure vessels may be made on-stream by installing a properly designed and applied nonmetallic composite wrap if the repair is approved by the engineer. The design shall include control of axial thrust loads if the part being repaired is (or may become) insufficient to control pressure thrust. Such temporary repairs shall be in accordance with ASME PCC-2, Part 4, Article 401 for high risk applications and 402 for low risk applications. Composite repairs shall be reviewed by the engineer in preparation for the next turnaround to determine if they need to be removed and the pressure vessel needs to be refurbished.

8.3 Permanent Repair

8.3.1 Permanent Repair Techniques

Typical permanent repair techniques include the following.

a) excavating the defect and blend-grinding to contour in accordance with API 579-1/ASME FFS-1 (also refer to ASME PCC-2, Article 304 for guidance on flaw excavation and weld repair);

b) excavating a defect and repair welding of the excavation;

c) replacing a section or the component containing the defect;

d) weld overlay of corroded area;

e) adding strip or plate lining to the interior surface.

Repairing a crack at a discontinuity, where stress concentrations are high (e.g., crack in a nozzle-to-shell weld), should not be attempted without prior consultation with an engineer.

8.3.2 Insert Plates

Damaged or corroded shell plates may be repaired by removing a section and replacing it with an insert patch (flush patch) that meets the applicable construction code. Insert patches may be used if the following requirements are met.

a) Full-penetration groove welds are provided. ASME *BPVC, Section VIII, Division 2*, 7.5.5

b) The welds are radiographed in accordance with the applicable construction code. Ultrasonic examination in accordance with *ASME BPVC* Case 2235 or *ASME BPVC, Section VIII, Division 2*, 7.5.5 may be substituted for the radiography if the NDE procedures are approved by the inspector.

c) All insert plate corners that do not extend to an existing longitudinal or horizontal weld shall be rounded having a 25 mm (1 in.) minimum radius. Weld proximity to existing welds shall be reviewed by the engineer.

Refer to ASME PCC-2, Article 201 for insert plate repairs.

8.3.3 Filler Metal Strength for Overlay and Repairs to Existing Welds

8.3.3.1 The filler metal used for weld repairs to vessel base metal should have minimum specified tensile strength equal to or greater than the minimum specified tensile strength of the base metal.

8.3.3.2 If a filler metal is used that has a minimum specified tensile strength lower than the minimum specified tensile strength of the base metal, the compatibility of the filler metal chemistry with the base metal chemistry shall be considered regarding weldability and service damage. In addition, all of the following shall be met.

a) The repair thickness shall not be more than 50 % of the required thickness of the base metal (this excludes corrosion allowance).

b) The thickness of the repair weld shall be increased by a ratio of minimum specified tensile strength of the base metal and minimum specified tensile of the filler metal used for the repair.

$$T_{\text{fill}} = d \times S_{\text{base}}/S_{\text{fill}} \tag{8}$$

where

T_{fill}	is the thickness of repair weld metal, in mm (in.);
d	is the depth of base metal lost by corrosion and weld preparation, in mm (in.);
S_{base}	is the base metal tensile strength, in MPa (ksi);
S_{fill}	is the filler metal tensile strength, in MPa (ksi).

c) The increased thickness of the repair shall have rounded corners and shall be blended into the base metal using a 3-to-1 taper.

d) The repair shall be made with a minimum of two passes.

8.3.4 Repairs to Stainless Steel Weld Overlay and Cladding

8.3.4.1 The repair weld procedure(s) to restore removed, corroded, or missing clad or overlay areas shall be reviewed and approved by the engineer and inspector before implementation.

8.3.4.2 The following factors shall be reflected in the repair plan: stress level, P-number of base material, service environment, possible previously dissolved hydrogen, type of lining, deterioration of base metal properties (by temper embrittlement of chromium-molybdenum alloys or other damage mechanisms causing loss of toughness), minimum pressurization temperatures, and a need for future periodic examination.

8.3.4.3 For equipment exposed to atomic hydrogen migration in the base metal (operates in hydrogen service at an elevated temperature or has exposed base metal areas open to corrosion), these additional factors shall be considered by the engineer when developing the repair plan:

a) outgassing base metal;

b) hardening of base metal due to welding, grinding, or arc gouging;

c) preheat and interpass temperature control;

d) PWHT to reduce hardness and restore mechanical properties.

These repairs shall be monitored by an inspector to assure compliance to repair requirements. After cooling to ambient temperatures, the repair shall be inspected by the PT method, according to ASME *BPVC, Section VIII, Division 1*, Appendix 8.

8.3.4.4 For vessels constructed with P-3, P-4, or P-5 base materials, the base metal in the area of repair should also be examined for cracking by the UT in accordance with ASME *Code, Section V*, Article 4, Paragraph T-473. This inspection is most appropriately accomplished following a delay of at least 24 hours after completed repairs for alloys that could be affected by delayed cracking.

8.3.4.5 Refer to ASME PCC-2, Article 211 for additional information on weld overlay and clad restoration.

8.4 Welding and Hot Tapping

8.4.1 General

All repair and alteration welding shall be in accordance with the applicable requirements of the ASME *BPVC* or the applicable construction or repair code, except as permitted in 8.1.2. Refer to API RP 582 and API RP 577 for additional welding considerations. Refer to API RP 2201 for safety aspects when making on-stream welds (e.g., during hot tapping) and to ASME PCC-2, Article 210 for technical guidance for in-service welding

8.4.2 Procedures, Qualifications, and Records

8.4.2.1 The repair organization shall use welders and welding procedures qualified in accordance with ASME *Code, Section IX* or those referenced by the construction code. Inspectors shall verify welders are welding within their ranges qualified on the welder's performance qualifications (WPQ) and within the ranges on the specified welding procedure specification (WPS).

8.4.2.2 The repair organization shall maintain and shall make available to the inspector the following records before the start of welding:

a) qualified WPS with their supporting procedure qualification record (PQR);

b) welder's qualification records;

c) welder continuity logs (a record that validates whether a welder has maintained his/her qualifications);

d) weld maps or other means to identify who made specific welds;

e) any other related records as specified by the owner-operator.

8.4.2.3 API RP 577 provides guidance on how to review weld procedures, procedure qualification records, welder performance qualifications, and how to respond to welding nonconformances.

8.4.3 Preheating

Preheat temperature used in making welding repairs shall be in accordance with the applicable code and qualified welding procedure. Exceptions shall be approved by the engineer and will require a new WPS be applied if the exception is a cooler preheat than specified in the current WPS. The inspector should assure the minimum preheat temperature is measured and maintained. For alternatives to traditional welding preheat, refer to ASME PCC-2, Article 208.

8.5 PWHT

8.5.1 General

PWHT of pressure vessel repairs or alterations should be made using the relevant requirements of the ASME *BPVC*, the applicable construction code, or an approved alternative PWHT procedure defined in 8.6. For field heat treating of vessels, refer to ASME PCC-2, Article 214.

8.5.2 Local PWHT

Local PWHT may be substituted for 360° banding on local repairs on all materials, provided the following precautions are taken and requirements are met.

a) The application is reviewed, and a procedure is developed by an engineer experienced in the appropriate engineering specialties.

b) The suitability of the procedure shall be evaluated considering the following factors:

1) base metal thickness;

2) decay thermal gradients;

3) material properties (e.g., hardness, constituents, and strength);

4) changes due to local PWHT;

5) the need for full-penetration welds;

6) surface and volumetric examinations after local PWHT;

7) the overall and local strains and distortions resulting from the heating of a local restrained area of the pressure vessel shell.

c) A preheat of 150 °C (300 °F) or higher, as specified by specific welding procedures, is maintained during welding.

d) The required local PWHT temperature shall be maintained for a distance of not less than two times the base metal thickness measured from the toe of the weld. The local PWHT temperature shall be monitored by a suitable number of thermocouples (at least two). When determining the number of thermocouples necessary, the size and shape of the area being heat treated should be considered.

e) Controlled heat shall be applied to any nozzle or any attachment within the local PWHT area.

f) When PWHT is performed for environmental-assisted cracking resistance, a metallurgical review shall be conducted to assess whether the procedure is acceptable.

8.5.3 Review of PWHT Charts

When PWHT has been conducted as part of a repair or replacement project, at a minimum the inspector shall carefully review the PWHT charts to determine if the specified PWHT temperatures and soak times were achieved for all sections and components of the vessel. In some cases, the owner-operator may assign a pressure vessel engineer or similar designee to complete the review and acceptance of the PWHT charts.

8.6 Preheat or Controlled-deposition Welding (CDW) Methods as Alternatives to PWHT

8.6.1 General

8.6.1.1 Refer to ASME PCC-2, Article 209 for additional information on alternatives to PWHT.

8.6.1.2 Preheat and CDW, as described in 8.6.2 and 8.6.3, may be used in lieu of PWHT where PWHT is inadvisable or mechanically unnecessary. Prior to using any alternative method, a metallurgical review conducted by an engineer shall be performed to assure the proposed alternative is suitable for the application. The review should consider factors such as the reason for the original PWHT of the equipment, susceptibility to stress corrosion cracking, stresses in the location of the weld, susceptibility to high-temperature hydrogen attack, susceptibility to creep, etc. The inspector is responsible for verifying the methods used are in accordance with owner-operator specification and the requirements of this section.

8.6.1.3 Selection of the welding method used shall be based on the rules of the construction code applicable to the work planned along with technical consideration of the adequacy of the weld in the as-welded condition at operating and pressure test conditions.

8.6.1.4 When reference is made in this section to materials by the ASME designation, P-number, and group number, the requirements of this section apply to the applicable materials of the applicable construction code, either ASME or other, which conform by chemical composition and mechanical properties to the ASME P-number and group number designations.

8.6.1.5 Vessels constructed of steels other than those listed in 8.6.2 and 8.6.3 that initially required PWHT, shall be postweld heat treated if alterations or repairs involving pressure boundary welding are performed. When one of the following methods is used as an alternative to PWHT, the PWHT joint efficiency factor may be continued if the factor has been used in the currently rated design.

8.6.2 Preheating Method (Notch Toughness Testing Not Required)

8.6.2.1 The preheating method, when performed in lieu of PWHT, is limited to the following materials and weld processes.

a) The materials shall be limited to P-No. 1, Groups 1, 2, and 3 and to P-No. 3, Groups 1 and 2 (excluding Mn-Mo steels in Group 2).

b) The welding shall be limited to the shielded metal arc welding (SMAW), gas metal arc welding (GMAW), and gas tungsten arc welding (GTAW) processes.

8.6.2.2 The preheat method shall be performed as follows.

a) The weld area shall be preheated and maintained at a minimum temperature of 150 °C (300 °F) during welding.

b) The 150 °C (300 °F) temperature should be checked to assure that 100 mm (4 in.) of the material or four times the material thickness (whichever is greater) on each side of the groove is maintained at the minimum temperature during welding. The maximum interpass temperature shall not exceed 315 °C (600 °F).

c) When the weld does not penetrate through the full thickness of the material, the minimum preheat and maximum interpass temperatures need only be maintained at a distance of 100 mm (4 in.) or four times the depth of the repair weld, whichever is greater on each side of the joint.

NOTE Notch toughness testing is not required when using this preheat method in lieu of PWHT.

8.6.3 CDW Method (Notch Toughness Testing Required)

The CDW method may be used in lieu of PWHT in accordance with the following.

a) Notch toughness testing, such as that established by ASME *BPVC, Section VIII, Division 1*, Parts UG-84 and UCS-66 is necessary when impact tests are required by the applicable construction code to the work planned.

b) The materials shall be limited to P-No. 1, P-No. 3, and P-No. 4 steels.

c) The welding shall be limited to the SMAW, GMAW, and GTAW processes.

d) A weld procedure specification shall be developed and qualified for each application. The welding procedure shall define the preheat temperature and interpass temperature and include the postheating temperature requirement in item f) 8). The qualification thickness for the test plates and repair grooves shall be in accordance with Table 3. The test material for the welding procedure qualification shall be of the same material specification (including specification type, grade, class, and condition of heat treatment) as the original material specification for the repair. If the original material specification is obsolete, the test material used should conform as much as possible to the material used for construction, but in no case shall the material be lower in strength or have a carbon content of more than 0.35 %.

e) When impact tests are required by the construction code applicable to the work planned, the PQR shall include sufficient tests to determine if the toughness of the weld metal and the heat-affected zone of the base metal in the as-welded condition is adequate at the MDMT (such as the criteria used in *ASME BPVC, Section VIII, Division 1*, Parts UG-84 and UCS 66). If special hardness limits are necessary (e.g., as set forth in NACE SP0472 and NACE MR0103) for stress corrosion cracking resistance, the PQR shall include hardness tests as well.

f) The WPS shall include the following additional requirements.

1) The supplementary essential variables of ASME *Code, Section IX*, Paragraph QW-250 shall apply.

2) The maximum weld heat input for each layer shall not exceed that used in the procedure qualification test.

3) The minimum preheat temperature for welding shall not be less than that used in the procedure qualification test.

4) The maximum interpass temperature for welding shall not be greater than that used in the procedure qualification test.

5) The preheat temperature shall be checked to assure that 100 mm (4 in.) of the material or four times the material thickness (whichever is greater) on each side of the weld joint will be maintained at the minimum temperature during welding. When the weld does not penetrate through the full thickness of the material, the minimum preheat temperature need only be maintained at a distance of 100 mm (4 in.) or four times the depth of the repair weld, whichever is greater on each side of the joint.

6) For the welding processes in item c), use only electrodes and filler metals classified by the filler metal specification with an optional supplemental diffusible-hydrogen designator of H8 or lower. When shielding gases are used with a process, the gas shall exhibit a dew point no higher than –50 °C (–60 °F). Surfaces on which welding will be done shall be maintained in a dry condition during welding and shall be free of rust, mill scale, and hydrogen-producing contaminants such as oil, grease, and other organic materials.

7) The welding technique shall be a CDW, temper bead, or half bead technique. The specific technique shall be used in the procedure qualification test.

8) For welds made by SMAW, after completion of welding and without allowing the weldment to cool below the minimum preheat temperature, the temperature of the weldment shall be raised to a temperature of 260 °C ± 30 °C (500 °F ± 50 °F) for a minimum period of two hours to assist outgassing diffusion of any weld metal hydrogen picked up during welding. This hydrogen bakeout treatment may be omitted, provided the electrode used is classified by the filler metal specification with an optional supplemental diffusible-hydrogen designator of H4 (such as E7018-H4).

9) After the finished repair weld has cooled, the final temper bead reinforcement layer shall be removed, leaving the weld substantially flush with the surface of the base material.

Refer to WRC Bulletin 412 for additional supporting technical information regarding CDW.

Table 3—Qualification Limits for Base Metal and Weld Deposit Thicknesses for the CDW Method (Notch Toughness Testing Required)

Depth *t* of Test Groove Welded [a]	Repair Groove Depth Qualified	Thickness *T* of Test Coupon Welded	Thickness of Base Metal Qualified
t	<*t*	50 mm (<2 in.)	<*T*
t	<*t*	50 mm (>2 in.)	50 mm (2 in.) to unlimited

[a] The depth of the groove used for procedure qualification shall be deep enough to allow removal of the required test specimens.

8.7 NDE of Welds

8.7.1 API RP 577 provides guidance on NDE of weld joints and weldments. Prior to welding, typically the area prepared for welding is examined using a surface NDE technique, e.g., the MT or PT technique to determine if defects are present. This examination is especially important after removing cracks and other critical defects.

8.7.2 After the weld is completed, it shall be examined again by the appropriate NDE technique as required in the repair specification to determine if defects exist using acceptance standards included in the repair spec or the applicable construction code.

8.7.3 New welds (as part of a pressure vessel repair or alteration) that were originally required by the construction code to be radiographed (e.g., circumferential and longitudinal welds) shall be radiographically examined in accordance with the construction code. In situations where it is not practical to perform radiography, the accessible surfaces of each nonradiographed new weld shall be fully examined using UT in lieu of RT and/or other appropriate NDE techniques to determine no defects exist. UT in lieu of RT shall follow ASME Sec V: APPENDIX VIII — Ultrasonic Examination Requirements for Fracture Mechanics Based Acceptance Criteria. If other techniques are used rather than the UT in lieu of RT, the joint efficiency should be reduced to the value corresponding to no radiography. Where use of NDE techniques specified by the construction code is not possible or practical, alternative NDE techniques may be used provided they are approved by the engineer and inspector.

8.7.4 Acceptance criteria for welded repairs or alterations should be in accordance with the applicable sections of the ASME *BPVC* or another applicable vessel design code.

8.8 Weld Inspection for Vessels Subject to Brittle Fracture

For vessels constructed of materials that may be subject to brittle fracture (per API 579-1/ASME FFS-1, or other analysis) from either normal or abnormal service (including start-up, shutdown, and pressure testing), appropriate inspection should be considered after welded repairs or alterations. Flaws, notches, or other stress risers could initiate a brittle fracture in subsequent pressure testing or service. MT and other effective surface NDE methods should be considered. Inspection techniques should be selected to detect critical flaws as determined by an FFS assessment.

All vessels subject to brittle fracture from low-temperature excursions or low ambient temperatures that may need weld repairs and that do not have an established MDMT or MAT shall be evaluated for these limits prior to being returned to service. Where a process excursion has the potential to generate temperature below the MAT(s), a process hazard analysis should be completed to evaluate the risk and the appropriate controls, alarms, and interlocks put in place to mitigate the risk to an acceptable level. Operating limits for the MAT should also be established. Low ambient temperature excursions or other process issues may be managed procedurally or with an IOW.

8.9 Rerating

8.9.1 Rerating a pressure vessel by changing its design temperature, minimum metal design temperature, or MAWP may be done only after all of the following requirements have been met.

a) Calculations performed by either the manufacturer or an owner-operator engineer (or his/her designated representative) experienced in pressure vessel design, fabrication, or inspection shall justify rerating.

b) A rerating shall be performed in accordance with the requirements of the vessel's applicable construction code. Alternately, calculations can be made using the appropriate formulas in the latest edition of the construction code provided all of the vessel's essential details comply with the applicable requirements of the ASME *BPVC*. If the vessel was designed to an edition or addendum of the ASME *BPVC* earlier than the 1999 addendum and was not designed to ASME *BPVC* Case 2290 or ASME *BPVC* Case 2278, it may be rerated to the latest edition/addendum of the ASME *BPVC* if permitted by Figure 1. Notice that for vessels built to a code earlier than 1968, the original design allowable stress (based on design factor of 4.0 or 5.0) shall be used.

c) Current inspection records verify the pressure vessel is satisfactory for the proposed service conditions and the corrosion allowance provided is appropriate. An increase in allowable working pressure or design temperature shall be based on thickness data obtained from a recent internal or on-stream inspection.

d) The vessel shall be pressure tested using the applicable testing formula from the code used to perform the rerating calculations unless either of the following is true:

   1) the pressure vessel has at some time been pressure tested to a test pressure equal to or higher than the test pressure required by the construction code; and

   2) the vessel integrity is confirmed by special nondestructive evaluation inspection techniques in lieu of testing.

e) The rerating is acceptable to the engineer.

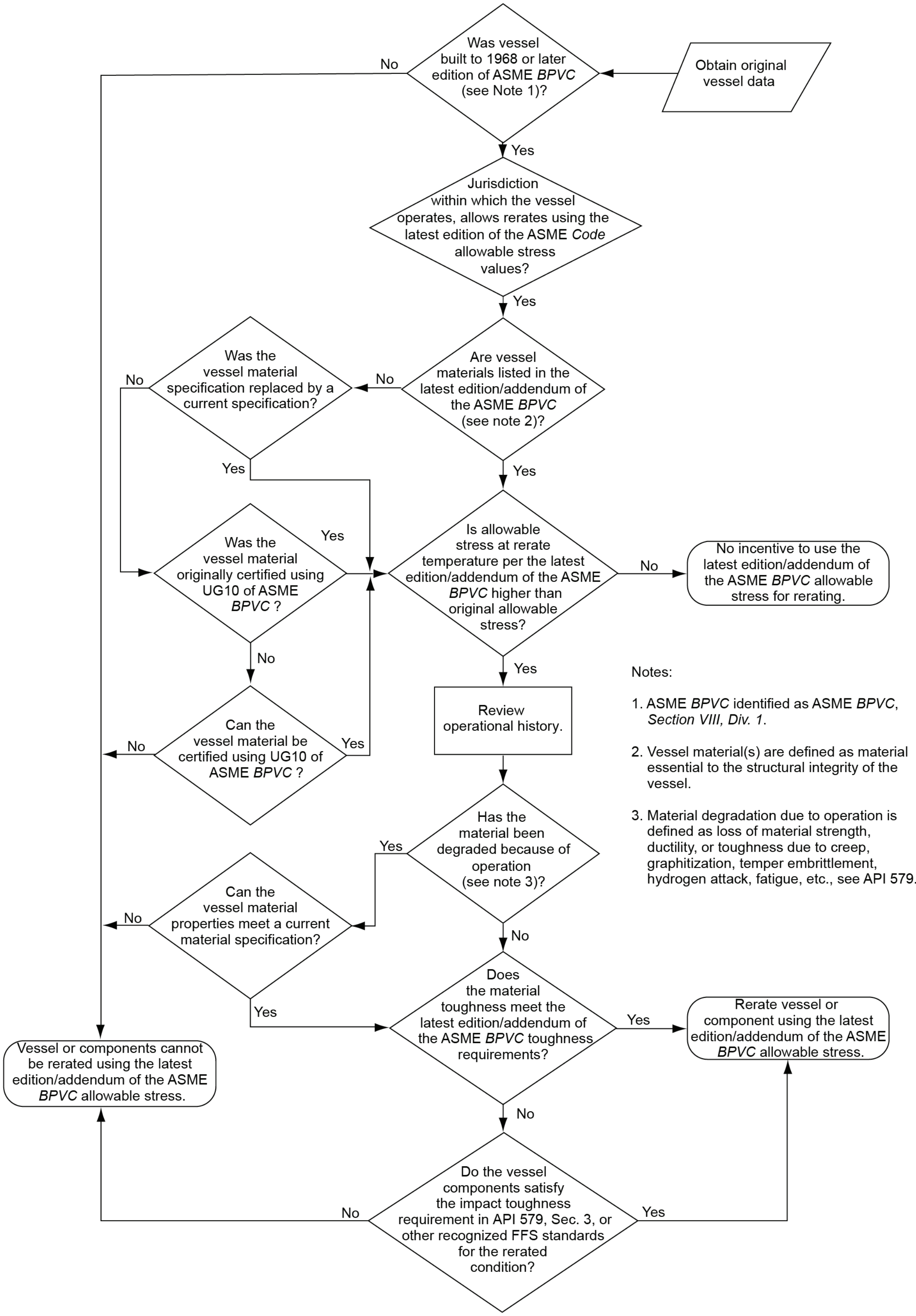

Figure 1—Rerating Vessels Using the Latest Edition or Addendum of the ASME *BPVC* Allowable Stresses

8.9.2 The pressure vessel rerating will be considered complete when the appropriate engineering records are updated followed by the attachment of an additional nameplate or additional stamping that carries the information in Figure 2.

Rerated by: ____

Date Rerated:______________________________20______

SAP No: ______________________________________

MAWP:_____________PSIG @____________F

MDMT:_____________F @________PSIG

Test Pressure:_____________PSIG

Figure 2—Sample Additional Nameplate

9 Alternative Rules for Exploration and Production (E&P) Pressure Vessels

9.1 Scope and Specific Exemptions

9.1.1 This section sets forth the minimum inspection rules for pressure vessels in E&P services. Typical E&P services include pressure vessels associated with drilling, production, gathering, transportation, and treatment of liquid petroleum, natural gas, natural gas liquids, and associated salt water (brine). Pressure vessels in E&P services shall follow all sections of the API 510 inspection code, except for Section 6, as referenced in 9.3 and 9.4. Owner-operators may choose to use Section 6 instead of these paragraphs. These rules are provided because of the vastly different characteristics and needs of pressure vessels used for E&P service. E&P service conditions typically:

a) operate at relatively lower temperatures, often eliminating high-temperature damage mechanisms (e.g., HTHA and creep);

b) have smaller numbers of credible damage mechanisms with higher predictability and lower complexity;

c) tend to be steady state service as opposed to thermal cyclical or batch (mole sieves, cokers, reactors, etc.)

In some E&P applications, material selection and mechanical design can provide inherently safer designs that reduce or eliminate in-service damage mechanisms. Some E&P facilities are of a complex nature where the owner-operator may decide to not employ Section 9.

9.1.2 The following are specific exemptions.

a) Portable pressure vessels and portable compressed gas containers associated with construction machinery, pile drivers, drilling rigs, well-servicing rigs and equipment, compressors, trucks, ships, boats, and barges shall be treated for inspection and recording purposes as a part of that machinery and shall be subject to prevailing rules and regulations applicable to that specific type of machine or container.

b) Pressure vessels referenced in Annex A are exempt from the specific requirements of this inspection code.

9.2 Inspection Program

9.2.1 General

Each owner-operator of vessels covered by Section 9 therefore exempted from the rules set forth in Section 6 of this document shall have an inspection program that will assure the vessels have sufficient integrity for the intended service. Each E&P owner-operator shall have the option of employing, within the limitations of the jurisdiction in which the vessels are located, any appropriate engineering, inspection, classification, and recording systems that meet the requirements of this document.

9.2.2 On-stream or Internal Inspections

Either an on-stream inspection or an internal inspection may be used interchangeably to satisfy inspection requirements.

a) An internal inspection is required when the vessel integrity cannot be established with an on-stream inspection. When an on-stream inspection is used, the scope (coverage, interval, technique, and so forth) may be increased as a result of inspection findings.

b) In selecting the technique(s) to be used for the inspection of a pressure vessel, both the condition of the vessel and the environment in which it operates should be taken into consideration. The inspection may include any number of nondestructive techniques, including visual inspection, as deemed necessary by the owner-operator.

c) At each on-stream or internal inspection, the remaining life shall be determined as described in 7.2.

9.2.3 Remaining Life Determination

9.2.3.1 For a new vessel, a vessel for which service conditions are being changed, or existing vessels, the remaining life shall be determined for each vessel or estimated for a class of vessels (pressure vessels used in a common circumstance of service, pressure, and risk) based on the following formula:

$$\text{Remaining life} = \frac{t_{\text{actual}} - t_{\text{required}}}{\text{corrosion rate}} \tag{9}$$

where

t_{actual} is the actual thickness, in mm (in.), measured at the time of inspection for a given location or component;

t_{required} is the required thickness, in mm (in.), at the same location or component as the t_{actual} measurement, obtained by one of the following methods:

a) the nominal thickness in the uncorroded condition, less the specified corrosion allowance;

b) the original measured thickness, if documented, in the uncorroded condition, less the specified corrosion allowance;

c) calculations in accordance with the requirements of the applicable construction code or by computations determined using the appropriate formulas in the latest edition of the ASME *BPVC*, if all of the essential details comply with the applicable requirements of the code being used.

$$\text{Corrosion rate} = \text{loss of metal thickness, in mm (in.), per year}$$

For vessels in which the corrosion rate is unknown, the corrosion rate shall be determined by one of the following methods:

1) calculated from data collected by the owner-operator on vessels in the same or similar service;

2) determined through appropriately placed ultrasonic sensors on the equipment;

3) estimated by a corrosion specialist;

4) estimated from published data on vessels in same or similar service.

In a case where items listed 1) through 2) cannot be applied with confidence and to ensure that an unexpected accelerated corrosion rate does not occur unidentified, the inspection plan shall include determining wall loss change rate on-stream by direct measurement techniques after six months of service. This may not determine an actual corrosion rate (because of potential measure error) but ensures data is available to direct the inspection plan until a corrosion rate can be established. This is provided as a cautionary guideline due to the statistical variation in thickness readings taken in short interval, which may suggest a corrosion rate that is not truly indicative of the environment.

Subsequent determinations shall be made at appropriate intervals until a credible corrosion rate is established. If it is later determined that an inaccurate corrosion rate was assumed, the corrosion rate in the remaining life calculations shall be changed to the actual corrosion rate.

9.2.3.2 The remaining life shall be determined by an individual experienced in pressure vessel design and/or inspection. If it is determined an inaccurate assumption has been made for either corrosion rate or thickness, the remaining life shall be increased or decreased to agree with the actual rate or thickness.

9.2.3.3 Other failure mechanisms (stress corrosion, brittle fracture, blistering, and so forth) shall be taken into account when determining the remaining life of the vessel.

9.2.4 External Inspections

The following applies to external inspections.

a) The external visual inspection shall, at least, determine the condition of the shell, heads, nozzles, exterior insulation, supports and structural parts, PRDs, allowance for expansion, and general alignment of the vessel on its supports. Any signs of leakage should be investigated so the sources can be established. It is not necessary to remove insulation if the entire vessel shell is maintained at a temperature sufficiently low or sufficiently high to prevent the condensation of moisture. Refer to API RP 572 for guidelines on external vessel inspections.

b) Buried sections of vessels shall be monitored to determine their external environmental condition. This monitoring shall be done at intervals that shall be established based on corrosion rate information obtained during maintenance activity on adjacent connected piping of similar material, information from the interval examination of similarly buried corrosion test coupons of similar material, information from representative portions of the actual vessel, or information from a sample vessel in similar circumstances.

c) Vessels known to have a remaining life of over 10 years or that are protected against external corrosion— for example,

   1) vessels insulated effectively to preclude the entrance of moisture;

   2) jacketed cryogenic vessels;

   3) vessels installed in a cold box in which the atmosphere is purged with an inert gas;

   4) vessels in which the temperature being maintained is sufficiently low or sufficiently high to preclude the presence of water do not need to have insulation removed for the external inspection; however, the condition of their insulating system or their outer jacketing, such as the cold box shell, shall be observed at least every five years and repaired if necessary.

9.2.5 Inspection Intervals

9.2.5.1 General

The pressure vessel owner-operator shall have the option to establish vessel inspection classes by grouping vessels into common classes of service, pressure, and/or risk. Vessel classifications shall be determined by an individual(s) experienced in the criteria outlined in the following. If vessels are grouped into classes (such as lower and/or higher risk), at a minimum, the following shall be considered to establish the risk class:

a) potential for vessel failure, such as MDMT; potential for cracking, corrosion, and erosion; and the existence of mitigation factors;

b) vessel history, design, and operating conditions, such as the type and history of repairs or alterations, age of vessel, remaining corrosion allowance, properties of contained fluids, operating pressure, and temperature relative to design limits;

c) consequences of vessel failure, such as location of vessel relative to employees or the public, potential for equipment damage, and environmental consequences.

9.2.5.2 RBI

RBI can be used to determine inspection intervals and the type and extent of future inspection/examinations. Refer to 5.2 for general requirements. In addition, the requirements below shall also be met.

a) An RBI assessment may be used to establish the appropriate inspection intervals for internal, on-stream, and external inspections, as well as inspection and testing intervals for PRDs. The RBI assessment may allow previously established inspection intervals to be exceeded from limits specified in 6.4 and 6.5, including the 10-year inspection and one-half remaining life limits for internal and on-stream inspections and the 5-year inspection limit for the external inspections.

b) When an RBI interval for the internal or on-stream inspection exceeds the 10-year limit, the RBI assessment shall be reviewed and approved by the engineer and inspector at intervals not to exceed 10 years or more often if warranted by process, equipment, or consequence changes.

c) When an RBI assessment is used to extend the internal or on-stream inspection interval, the assessment should include a review of the inspection history and potential fouling of the vessel's PRD(s).

9.2.5.3 Risk Classification

The following applies to inspection intervals.

a) When risk classification is used, inspections shall be performed at intervals determined by the vessel's risk classification. If the owner-operator decides to not classify vessels into risk classes, the inspection requirements and intervals of higher-risk vessels shall be followed. The owner-operator shall define and document how to determine lower and higher risk classification. When additional classes are established, inspection and sampling intervals shall be set between the higher risk and lower risk classes, as determined by the owner-operator. If the owner-operator decides to use RBI, then the interval, extent, and methods of inspection shall be determined by the RBI analysis. The inspection intervals for the two main risk classifications (lower and higher) are defined below.

b) Lower-risk vessels shall be inspected as follows.

   1) Inspections on a representative sample of vessels in that class, or all vessels in that class, may be performed.

   2) External inspections shall be performed when an on-stream or internal inspection is performed or at shorter intervals at the owner-operator's option.

   3) On-stream or internal inspections shall be performed at least every 15 years or three-fourths remaining life, whichever is less.

4) Any signs of leakage or deterioration detected in the interval between inspections shall require an on-stream or internal inspection of that vessel and a reevaluation of the inspection interval for that vessel class.

c) Higher-risk vessels shall be inspected as follows.

1) External inspections shall be performed when an on-stream or internal inspection is performed or at shorter intervals at the owner-operator's option.

2) On-stream or internal inspections shall be performed at least every 10 years or one-half remaining life, whichever is less.

3) In cases where the remaining life is estimated to be less than four years, the inspection interval may be the full remaining life up to a maximum of two years. Consider increasing the number of vessels inspected within that class to improve the likelihood of detecting the worst-case corrosion.

4) Any signs of leakage or deterioration detected in the interval between inspections shall require an on-stream or internal inspection of that vessel and a reevaluation of the inspection interval for that vessel class.

d) Pressure vessels (whether grouped into classes or not) shall be inspected at intervals sufficient to insure their fitness for continued service. Operational conditions and vessel integrity may require inspections at shorter intervals than the intervals stated above.

e) If service conditions change, the maximum operating temperature, pressure, and interval between inspections shall be reevaluated.

f) For large vessels with two or more zones of differing corrosion rates, each zone may be treated independently regarding the interval between inspections.

9.2.6 Additional Inspection Requirements

Additional inspection requirements, regardless of vessel classification, exist for the following vessels.

a) Vessels that have changed ownership and location shall have an on-stream or internal inspection performed to establish the next inspection interval and to assure the vessel is suitable for its intended service. Inspection of new vessels is not required if a manufacturer's data report is available.

b) If a vessel is transferred to a new location, and it has been more than five years since the vessel's last inspection, an on-stream or internal inspection is required. (Vessels in truck-mounted, skid-mounted, ship-mounted, or barge-mounted equipment are not included.)

c) Air receivers (other than portable equipment) shall be inspected at least every five years unless inspected by RBI.

d) Portable or temporary pressure vessels employed for the purpose of testing oil and gas wells during completion or recompletion shall be inspected at least once during each three-year period of use. More frequent inspections shall be conducted if vessels have been in severe corrosive environments.

9.3 Pressure Test

When a pressure test is conducted, the test shall be in accordance with the procedures in 5.8.

9.4 Safety Relief Devices

Safety relief devices shall be inspected, tested, and repaired in accordance with 6.6.

9.5 Records

The following records requirements apply.

a) Pressure vessel owner-operators shall maintain pressure vessel records. The preferred method of recordkeeping is to maintain data by individual vessel. Where vessels are grouped into classes, data may be maintained by vessel class. When inspections, repairs, or alterations are made on an individual vessel, specific data shall be recorded for that vessel.

a) Examples of information that may be maintained are vessel identification numbers; safety relief device information; and the forms on which results of inspections, repairs, alterations, or reratings are to be recorded. Any appropriate forms may be used to record these results. A sample pressure vessel inspection record is shown in Annex C. A sample alteration or rerating of pressure vessel form is shown in Annex D. Information on maintenance activities and events that affect vessel integrity should be included in the vessel records.

Annex A
(normative)

Code Exemptions

Unless specified by the owner-operator, the following classes of containers and pressure vessels are excluded from the specific requirements of this inspection code:

a) pressure vessels on movable structures covered by jurisdictional regulations:

   1) cargo or volume tanks for trucks, ships, and barges;

   2) air receivers associated with braking systems of mobile equipment;

   3) pressure vessels installed in oceangoing ships, barges, and floating craft;

b) the following classes of containers listed for exemption from the scope of ASME *BPVC*, *Section VIII, Division 1*;

   1) fired process tubular heaters;

   2) pressure containers that are integral parts or components of rotating or reciprocating mechanical devices, such as pumps, compressors, turbines, generators, engines, and hydraulic or pneumatic cylinders in which the primary design considerations or stresses are derived from the functional requirements of the device;

   3) structures whose primary function is transporting fluids from one location to another within a system of which it is an integral part, that is, piping systems;

   4) piping components such as pipe, flanges, bolting, gaskets, valves, expansion joints, and fittings, and the pressure-containing parts of other components, such as strainers and devices which serve such purposes as mixing, separating, snubbing, distributing, and metering or controlling flow, provided that pressure-containing parts of such components are generally recognized as piping components or accessories;

   5) a vessel for containing water under pressure, including those containing air the compression of which serves only as a cushion, when none of the following limitations are exceeded:

      i) a design pressure of 2 MPa (300 psi);

      ii) a design temperature of 99 °C (210 °F);

   6) a hot water supply storage tank heated by steam or any other indirect means when the following limitations are not exceeded:

      i) a heat input of 58.6 kW (200,000 Btu/hr);

      ii) a water temperature of 99 °C (210 °F);

      iii) a nominal water-containing capacity of 450 L (120 gal);

   7) vessels not exceeding the design pressure at the top of the vessel, limitations below, with no limitation on size:

      i) vessels having an internal or external pressure not exceeding 100 KPa (15 psig);

ii) Combination units having an internal or external pressure in each chamber not exceeding 100 kPa (15 psi) and differential pressure on the common elements not exceeding 100 kPa (15 psi);

8) vessels having an inside diameter, width, height, or cross-sectional diagonal not exceeding 152 mm (6 1.0), with no limitation on length of vessel or pressure;

9) pressure vessels for human occupancy;

c) pressure vessels that do not exceed the following volumes and pressures:

1) 0.14 m^3 (5 ft^3) in volume and 1.7 MPa (250 psi) design pressure;

2) 0.08 m^3 (3 ft^3) in volume and 2.4 MPa (350 psi) design pressure;

3) 0.04 m^3 (1 1/2 ft^3) in volume and 4.1 MPa (600 psi) design pressure.

Annex B
(normative)

Inspector Certification

B.1 Examination

A written examination to certify inspectors within the scope of API 510 shall be based on the current API 510 *Inspector Certification Examination Body of Knowledge* as published by API.

To become an authorized API pressure vessel inspector, candidates must pass the examination.

B.2 Certification

To qualify for the certification examination, the applicant's education and experience, when combined, shall be equal to at least one of the following:

a) a bachelor of science degree in engineering or technology, or three plus years of military service in a technical role (dishonorable discharge disqualifies credit), plus one year of experience in supervision of inspection activities or performance of inspection activities as described in API 510;

b) a two-year degree or certificate in engineering or technology or two years of military service in a technical role (dishonorable discharge disqualifies credit), plus two years of experience in the design, fabrication, repair, inspection, or operation of pressure vessels, of which one year must be in supervision of inspection activities or performance of inspection activities as described in API 510;

c) a high school diploma or equivalent, plus three years of experience in the design, fabrication, repair, inspection, or operation of pressure vessels, of which one year must be in supervision of inspection activities or performance of inspection activities as described in API 510;

d) a minimum of five years of experience in the design, fabrication, repair, inspection, or operation of pressure vessels, of which one year must be in supervision of inspection activities or performance of inspection activities as describe in API 510.

B.3 Recertification

B.3.1 Recertification is required three years from the date of issuance of the API 510 authorized pressure vessel inspector certification. Inspectors who are recertifying shall meet all recertification requirements as defined below. Recertification by written examination will be required for inspectors who have not been actively engaged as inspectors within the most recent three-year certification period or who fail to meet the recertification requirements prior to the end of their expiration grace period. Exams will be in accordance with all provisions contained in API 510.

B.3.2 "Actively engaged as an inspector" shall be defined by one of the following provisions:

a) a minimum of 20 % of time spent performing inspection activities, supervising inspection activities, or engineering support of inspection activities as described in the API 510 inspection code, over the most recent three-year certification period;

b) performance of inspection activities, supervising inspection activities, or engineering support of inspection activities on pressure vessels as described in API 510 over the most recent three-year certification period.

NOTE Inspection activities common to other API inspection documents (NDE, recordkeeping, review of welding documents, etc.) may be considered here.

B.3.3 Beginning January 1, 2022, API's Individual Certification Plans (ICP) will include continuing professional development (CPD) hours in its three-year recertification requirements for API 510. ICP will have a phased implementation of the CPD hour requirement beginning with eight CPD hours required for individuals whose certification expires after January 1, 2023. The full CPD requirements of 24 CPDs will be implemented for those expiring on or after January 1, 2025.

B.3.4 Once every other recertification period (every six years), actively engaged inspectors shall demonstrate knowledge of revisions to API 510 and other API documents listed in the body of knowledge (BOK), which are identified in the relevant Web Quiz Publication Effectivity sheet that were instituted during the previous six years or are still a relevant edition. This requirement shall be effective six years from the inspector's initial certification date.

Annex C
(informative)

Sample Pressure Vessel Inspection Record

NOTE The following are merely examples for illustration purposes only. [Each company should develop its own approach.] They are not to be considered exclusive or exhaustive in nature. API makes no warranties, express or implied for reliance on or any omissions from the information contained in this document.

SAMPLE PRESSURE VESSEL
INSPECTION RECORD
API 510, 10th EDITION

Form Date ______________________
Form No. ______________________
Owner or User ______________________
Vessel Name ______________________

Description	
Name of Process ______________	Owner-Operator Number ______________
Location ______________	Jurisdiction/National Board Number ______________
Internal Diameter ______________	Manufacturer ______________
Tangent Length/Height ______________	Manufacturer's Serial No. ______________
Shell Material Specification ______________	Date of Manufacture ______________
Head Material Specification ______________	Contractor ______________
Internal Materials ______________	Drawing Numbers ______________
Nominal Shell Thickness ______________	______________
Nominal Head Thickness ______________	Construction Code ______________
Design Temperature ______________	Joint Efficiency ______________
Maximum Allowable Working	Type Heads ______________
Pressure ______________	Type Joint ______________
Maximum Tested Pressure ______________	Flange Class ______________
Design Pressure ______________	Coupling Class ______________
Relief Valve Set Pressure ______________	Number of Manways ______________
Contents ______________	Weight ______________
Special Conditions ______________	

Thickness Measurements

Sketch or Location Description	Location Number	Original Thickness	Required Minimum Thickness	Date

Comments (See Note 2) ______________________

Method ______________________

Authorized Inspector ______________________

NOTE 1 Use additional sheets, as necessary.
NOTE 2 The location that each comment relates to must be described.

Annex D
(informative)

Sample Repair, Alteration, or Rerating of Pressure Vessel Form

NOTE The following are merely examples for illustration purposes only. [Each company should develop its own approach.] They are not to be considered exclusive or exhaustive in nature. API makes no warranties, express or implied for reliance on or any omissions from the information contained in this document.

SAMPLE REPAIR ALTERATION OR RERATING OF PRESSURE VESSEL FORM API 510, 10th EDITION

Form Date ______________________
Form No. ______________________
Owner-Operator Name ______________________
Vessel Name ______________________

1. Original Vessel Identification Number ______________________
2. Original Vessel Location ______________________
3. Manufacturer ______________________ Serial No. ______________________
____
____
4. See attachments for additional data? o Yes o No
5. Original Construction Code ______________________
6. Original Maximum Allowable Working Pressure ______________________ Year Built ______________________
7. Original Design Temperature______________________ Year Built ______________________
8. Original Minimum Design Metal Temperature ______________________ At Pressure______________________
9. Original Test Pressure ______________________ Fluid ____________ Position ______________________
10. Shell Material ______________________ Head Material ______________________
____
____
11. Shell Thickness ______________________ Head Thickness ______________________
12. Original Joint Efficiency ______________________
13. Original Radiography o Yes o No
14. Original PWHT o Yes o No
If yes, ____________Temp (°F) ____________ Time (Hrs)
15. Original Corrosion Allowance ______________________
16. Work on Vessel Classified as: o Repair o Alteration o Rerating
17. Organization Performing Work ______________________
18. Construction Code for Present Work ______________________
19. New Vessel Identification Number (if Applicable) ______________________
20. New Vessel Location (if Applicable) ______________________
21. New Maximum Allowable Working Pressure ______________________
22. New Design Temperature ______________________
23. New Minimum Design Metal Temperature ______________________ At Pressure ______________________
24. New PWHT o Yes o No
____________Temp (°F) ____________ Time (Hrs)
25. New Joint Efficiency, if Applicable E = ____________
26. Type of Examination or Inspection Performed:
o radiographic o ultrasonic
o magnetic particle o penetrant
o visual o other
27. New Pressure Test if Yes, Pressure ____________ Test Medium ____________ Test Position ____________
28. New Corrosion Allowance ______________________
29. Describe work performed (attach drawings, calculations, and other pertinent data):
____
____
____

Statement of Compliance

We certify that the statements made in this report are correct and that all material and construction for and workmanship of this o repair o alteration, o rerating conform to the requirements of the __________Edition of API 510, Pressure Vessel Inspection Code.

____
(repair, alteration, or rerating organization)
Signed ______________________
(authorized representative)
Date ______________________

Statement of Inspection

I, the undersigned, an inspector employed by ______________________ , having inspected the work described above, state that to the best of my knowledge, the work has been satisfactorily completed in accordance with the ____________ Edition of API 510, Pressure Vessel Inspection Code.

Signed ______________________
API 510 Certification Number ______________________
Date ______________________

Annex E
(informative)

Technical Inquiries

E.1 Introduction

API will consider written requests for interpretations of API 510. API staff will make such interpretations in writing after consultation, if necessary, with the appropriate committee officers and the committee membership. The API committee responsible for maintaining API 510 meets regularly to consider written requests for interpretations and revisions and to develop new criteria as dictated by technological development. The committee's activities in this regard are limited strictly to interpretations of the standard or to the consideration of revisions to the present standard on the basis of new data or technology. As a matter of policy, API does not approve, certify, rate, or endorse any item, construction, proprietary device, or activity; accordingly, inquiries requiring such consideration will be returned. Moreover, API does not act as a consultant on specific engineering problems or on the general understanding or application of the rules. If, based on the inquiry information submitted, it is the opinion of the committee that the inquirer should seek assistance, the inquiry will be returned with the recommendation that such assistance be obtained. All inquiries that cannot be understood because they lack information will be returned.

E.2 Inquiry Format

Inquiries shall be limited strictly to requests for interpretation of the standard or to the consideration of revisions to the standard on the basis of new data or technology. Inquiries shall be submitted in the following format.

a) *Scope*—The inquiry shall involve a single subject or closely related subjects. An inquiry letter concerning unrelated subjects will be returned.

b) *Background*—The inquiry letter shall state the purpose of the inquiry, which shall be either to obtain an interpretation of the standard or to propose consideration of a revision to the standard. The letter shall concisely provide the information needed for complete understanding of the inquiry (with sketches, as necessary). This information shall include reference to the applicable edition, revision, paragraphs, figures, and tables.

c) *Inquiry*—The inquiry shall be stated in a condensed and precise question format. Superfluous background information shall be omitted from the inquiry, and where appropriate, the inquiry shall be composed so that "yes" or "no" (perhaps with provisos) would be a suitable reply. This inquiry statement should be technically and editorially correct. The inquirer shall state what he/she believes the standard requires. If in his/her opinion a revision to the standard is needed, he/she shall provide recommended wording. The inquiry should be typed; however, legible handwritten inquiries will be considered. The name and the mailing address of the inquirer must be included with the proposal. The proposal shall be submitted to the following address: Director of the Standards Department, American Petroleum Institute, 200 Massachusetts Avenue, NW, Suite 1100, Washington, DC 20001, or via e-mail to standards@api.org.

E.3 Technical Inquiry Responses

Responses to previous technical inquiries can be found on the API website at http://mycommittees.api.org/standards/techinterp/refequip/default.aspx.

Bibliography

[1] API Recommended Practice 586, *NDE Techniques*

[2] API Recommended Practice 588, *Source Inspection and Quality Surveillance of Fixed Equipment*

[3] API Recommended Practice 970, *Corrosion Control Documents*

[4] API Recommended Practice 2218, *Fireproofing Practices in Petroleum and Petrochemical Processing Plants*

[5] NBBI NB23,[3] *National Board Inspection Code*

[6] NACE MR0103,[4] *Materials Resistant to Sulfide Stress Cracking in Corrosive Petroleum Refining Environments*

[7] NACE SP0472, *Methods and Controls to Prevent In-service Environmental Cracking of Carbon Steel Weldments in Corrosive Petroleum Refining Environments*

[8] NACE SP0170, *Protection of Austenitic Stainless Steels and Other Austenitic Alloys from Polythionic Acid Stress Corrosion Cracking During Shutdown of Refinery Equipment*

[9] U.S. DOL Title 29, *CFR* Part 1910,[5] *Occupational Safety and Health Standards*

[10] WRC Bulletin 412,[6] *Challenges and Solutions in Repair Welding for Power and Processing Plants*

[3] The National Board of Boiler and Pressure Vessel Inspectors, 1055 Crupper Avenue, Columbus, Ohio 43229, www.nationalboard.org.

[4] AMPP (the Association for Materials Protection and Performance, formerly NACE International), 15835 Park Ten Place, Houston, Texas 77084, www.ampp.org.

[5] U.S. Department of Labor, Occupational Safety and Health Administration, 200 Constitution Avenue, NW, Washington, DC 20210, www.osha.gov.

[6] Welding Research Council, P.O. Box 201547, Shaker Heights, Ohio 44120, www.forengineers.org.

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