Tank Inspection, Repair, Alteration, and Reconstruction

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Portions of this publication have been changed from the previous edition. The locations of changes have been marked with a bar in the margin, as shown to the left of this paragraph. In some cases the changes are significant, while in other cases the changes reflect minor editorial adjustments such as renumbering of a section/subsection or figure/table (the references *within the text* that have been subsequently updated are not marked). The bar notations in the margins are provided as an aid to users, but API makes no warranty as to the accuracy of such bar notations.

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SECTION 1—SCOPE

1.1 Introduction

1.1.1 This standard covers steel storage tanks built to API 650 and its predecessor API 12C. It provides minimum requirements for maintaining the integrity of such tanks after they have been placed in service and addresses inspection, repair, alteration, relocation, and reconstruction.

1.1.2 The scope is limited to the tank foundation, bottom, shell, structure, roof, attached appurtenances, and nozzles to the face of the first flange, first threaded joint, or first welding-end connection. Many of the design, welding, examination, and material requirements of API 650 can be applied in the maintenance inspection, rating, repair, and alteration of in-service tanks. In the case of apparent conflicts between the requirements of this standard and API 650 or its predecessor API 12C, this standard shall govern for tanks that have been placed in service.

1.1.3 This standard has requirements given in two alternate systems of units. Any repairs shall comply with the original construction units, i.e. either:

a) all of the requirements given in this standard in metric (SI) units; or

b) all of the requirements given in this standard in U.S. customary (USC) units.

1.1.4 This standard employs the principles of API 650; however, storage tank owner/operators, based on consideration of specific construction and operating details, may apply this standard to any steel tank constructed in accordance with a tank specification.

1.1.5 This standard is intended for use by organizations that maintain or have access to engineering and inspection personnel technically trained and experienced in tank design, fabrication, repair, construction, and inspection.

1.1.6 This standard does not contain rules or guidelines to cover all the varied conditions which may occur in an existing tank. When design and construction details are not given, and are not available in the as-built standard, details that will provide a level of integrity equal to the level provided by the current edition of API 650 must be used.

1.1.7 This standard recognizes fitness-for-service assessment concepts for evaluating in-service degradation of pressure containing components. API 579-1/ASME FFS-1, *Fitness-For-Service*, provides detailed assessment procedures or acceptance criteria for specific types of degradation referenced in this standard. When this standard does not provide specific evaluation procedures or acceptance criteria for a specific type of degradation or when this standard explicitly allows the use of fitness-for-service criteria, API 579-1/ASME FFS-1 may be used to evaluate the various types of degradation or test requirements addressed in this standard.

1.2 Compliance with This Standard

The owner/operator has ultimate responsibility for complying with the provisions of this standard. The application of this standard is restricted to organizations that employ or have access to an authorized inspection agency as defined in 3.3. Should a party other than the owner/operator be assigned certain tasks, such as relocating and reconstructing a tank, the limits of responsibility for each party shall be defined by the owner/operator prior to commencing work.

1.3 Jurisdiction

If any provision of this standard presents a direct or implied conflict with any statutory regulation, the regulation shall govern. However, if the requirements of this standard are more stringent than the requirements of the regulation, then the requirements of this standard shall govern.

1.4 Safe Working Practices

An assessment shall be made of the potential hazards to which personnel may be exposed when conducting internal tank inspections, making repairs, or dismantling tanks. Procedures shall be developed according to the guidelines given in API Standard 2015 and API 2217A that will include safeguard for personnel health and safety, prevention of accidental fires and explosions, and the prevention of property damage. Conformance to permit procedures is an essential safe work practice for protection of personnel and property. Where welding and hot work are involved, API 2009 states “Except in areas specifically designated as safe for hot work, a hot work permit shall be obtained before starting any work that can involve a source of ignition.” See also API Standard 2015.

Special procedures may need to be developed for certain activities described in this standard that are not fully covered by the referenced API publications; e.g. safety precautions for personnel accessing floating roof tanks that are in service, or gas freeing the bottom side of a tank. Appendix B of API 2009 provides brief information on inerting tanks. Use of inerting as a safety precaution should address personnel hazards introduced when using inert gas in the workplace and implementation should be done in consultation with specialists that are familiar with such processes. Finally, procedures must comply with any federal or state safety regulations pertaining to “confined spaces” or any other relevant provisions.

SECTION 2—NORMATIVE REFERENCES

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

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

API Recommended Practice 580, *Risk Based Inspection*

API Standard 620, *Design and Construction of Large, Welded, Low-pressure Storage Tanks*

API Standard 650, *Welded Tanks for Oil Storage*

API Recommended Practice 651, *Cathodic Protection of Aboveground Storage Tanks*

API Recommended Practice 652, *Lining of Aboveground Petroleum Storage Tank Bottoms*

API Standard 2000, *Venting Atmospheric and Low-pressure Storage Tanks: Nonrefrigerated and Refrigerated*

API Recommended Practice 2003, *Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents*

API Recommended Practice 2009, *Safe Welding, Cutting, and Hot Work Practices in the Petroleum and Petrochemical Industries*

API Standard 2015, *Requirements for Safe Entry and Cleaning of Petroleum Storage Tanks*

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

API Recommended Practice 2207, *Preparing Tank Bottoms for Hot Work*

API Standard 2217A, *Guidelines for Safe Work in Inert Confined Spaces in the Petroleum and Petrochemical Industries*

ASME *Boiler and Pressure Vessel Code (BPVC)* [1], *Section V: Nondestructive Examination*

ASME *BPVC*, *Section VIII: Pressure Vessels; Division 2: Alternative Rules*

ASME *BPVC*, *Section IX: Welding and Brazing Qualifications*

ASNT SNT-TC-1A [2], *Personnel Qualification and Certification in Nondestructive Testing*

ASTM A6 [3], *Standard Specification for General Requirements for Rolled Structural Steel Bars, Plates, Shapes, and Sheet Piling*

ASTM A20, *Standard Specification for General Requirements for Steel Plates for Pressure Vessels*

ASTM A36, *Standard Specification for Carbon Structural Steel*

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1 ASME International, 3 Park Avenue, New York, New York 10016-5990, www.asme.org.
2 American Society for Nondestructive Testing, 1711 Arlingate Lane, Columbus, Ohio, 43228-0518, www.asnt.org.
3 ASTM International, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania 19428-2959, www.astm.org.

ASTM A370, *Standard Test Methods and Definitions for Mechanical Testing of Steel Products*

ASTM A992, *Standard Specification for Structural Steel Shapes*

AWS D1.1 [4], *Structural Welding Code—Steel*

AWS D1.6, *Structural Welding Code—Stainless Steel*

[4] American Welding Society, 550 N.W. LeJeune Road, Miami, Florida 33135, www.aws.org.

SECTION 3—TERMS AND DEFINITIONS

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

3.1
alteration
Any work on a tank that changes its physical dimensions or configuration.

3.2
as-built standard
The standard (such as API standard or UL [6] standard) used for the construction of the tank component in question. If this standard is not known, the as-built standard is the standard that was in effect at the date of the installation of the component. If the date of the installation of the component is unknown, then the current applicable standard shall be considered to be the as-built standard. See Annex A for a list of API welded storage tank standards. The standard used for repairs or alterations made after original construction is the as-built standard only for those repairs or alterations, so there may be more than one as-built standard for a tank.

3.3
authorized inspection agency
One of the following organizations that employ an aboveground storage tank inspector certified by API.

a) The inspection organization of the jurisdiction in which the aboveground storage tank is operated.

b) The inspection organization of an insurance company which is licensed or registered to and does write aboveground storage tank insurance.

c) An owner/operator of one or more aboveground storage tank(s) who maintains an inspection organization for activities relating only to his/her equipment and not for aboveground storage tanks 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 aboveground storage tank is operated. The owner/operator's inspection program shall provide the controls necessary for use by authorized inspectors contracted to inspect aboveground storage tanks.

3.4
authorized inspector
An employee of an authorized inspection agency who is qualified and certified to perform inspections under this inspection standard. Whenever the term inspector is used in API 653, it refers to an authorized API Standard 653 inspector.

3.5
breakover point
The area on a tank bottom where settlement begins.

3.6
candidate tank
The tank(s) for which corrosion rates are not known.

3.7
change in service
A change from previous operating conditions involving different properties of the stored product such as specific gravity or corrosivity and/or different service conditions of temperature and/or pressure.

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[6] Underwriters Laboratories, 333 Pfingsten Road, Northbrook, Illinois, 60062-2096, www.ul.com.

3.8
control tank
The tank(s) for which corrosion rates and service history are known and documented.

3.9
corrosion allowance
Any additional material thickness available to allow metal loss during the service life of the tank component. It may also represent additional thickness included in the original component design or specified by the purchaser to be added to the thickness for new components in the repair and reconstruction of tanks.

3.10
corrosion rate
The total metal loss divided by the period of time over which the metal loss occurred.

3.11
critical zone
The portion of the tank bottom or annular plate within 75 mm (3 in.) of the inside edge of the shell, measured radially inward.

3.12
current applicable standard
The current edition of the standard (such as API standard or UL standard) that applies if the tank were built today.

3.13
door sheet
A plate (or plates) cut from an existing tank shell to create a temporary access opening. After planned work is completed, the door sheet(s) shall be reinstalled or replaced.

3.14
examiner
A person who assists the inspector by performing specific nondestructive examination (NDE) on aboveground storage tanks and evaluates to the applicable acceptance criteria, but does not interpret the results of those examinations in accordance with API 653, unless specifically trained and authorized to do so by the owner/operator.

3.15
external inspection
A formal visual inspection, conducted or supervised by an authorized inspector, to assess all aspects of the tank as possible without suspending operations or requiring tank shutdown (see 6.3.2).

3.16
fitness-for-service assessment
A methodology whereby flaws contained within a structure are assessed in order to determine the adequacy of the flawed structure for continued service without imminent failure.

3.17
hot tap
Identifies a procedure for installing a nozzle in the shell of a tank that is in service.

3.18
hydrotest
A test performed with water, in which static fluid head is used to produce test loads.

3.19
insert plate
A steel plate that replaces part of a shell plate with a nominal thickness that is equivalent to, or no more than, 3 mm ($^1/_8$ in.) greater than the nominal thickness of the adjoining material. When an insert plate is equal to the full height of a shell ring, it is considered to be a shell plate.

3.20
inspection activities
Any activity relating to the performance of inspection of aboveground storage tanks while employed by or under contract with an authorized inspection agency.

3.21
inspector
A shortened title for an authorized tank inspector qualified and certified in accordance with this standard.

3.22
internal inspection
A formal, complete inspection, as supervised by an authorized inspector, of all accessible internal tank surfaces (see 6.4.1).

3.23
internal inspection deferral
An approved and documented postponement on the internal inspection due date of an in-service tank based on the procedures of 6.4.3.

3.24
internal inspection due date
The date whereby a tank is scheduled to 1) be emptied of liquid and removed from service for internal inspection or 2) complete an on-stream internal inspection. The date is based on 6.4.2.

3.25
major alteration/or major repair
An alteration or repair that includes any of the following:

a) installing a shell penetration larger than DN 300 mm (NPS 12) beneath the design liquid level;

b) installing a bottom penetration within 300 mm (12 in.) of the shell;

c) removing and replacing or adding a shell plate beneath the design liquid level where the longest dimension of the replacement plate exceeds 300 mm (12 in.);

d) removing or replacing annular plate ring material where the longest dimension of the replacement plate exceeds 300 mm (12 in.);

e) complete or partial (more than one-half of the weld thickness) removal and replacement of more than 300 mm (12 in.) of vertical weld joining shell plates or radial weld joining the annular plate ring;

f) a nonmetallic repair that contributes more than one-half the strength of the shell in an area more than 300 mm (12 in.) high;

g) installing a new bottom;

NOTE Installation of a portion of a new bottom as described in 12.3.4.3 is not defined as a major repair.

h) removing and replacing part of the weld attaching the shell to the bottom, or to the annular plate ring, in excess of the amounts listed in 12.3.3.5.1 a);

i) jacking a tank shell.

3.26
nominal thickness
The ordered thickness of the material. This thickness includes any corrosion allowance. If the ordered thickness is unknown, the nominal thickness should be determined based on existing plate measured thickness and the judgment of a storage tank engineer.

3.27
owner/operator
The legal entity having control of and/or responsibility for the operation and maintenance of an existing storage tank.

3.28
product-side
The side of the tank that is in contact with the stored liquid product.

3.29
recognized toughness
A condition that exists when the material of a component is deemed acceptable for use by the provisions of any of the following sections of this standard:

a) Section 5.3.2 (based on edition of standard of tank's original construction, or by coupon testing);

b) Section 5.3.5 (based on thickness);

c) Section 5.3.6 (based on lowest design metal temperature);

d) Section 5.3.8 (based on exemption curves).

3.30
reconstruction
Any work necessary to reassemble a tank that has been dismantled and relocated to a new site.

3.31
reconstruction organization
The organization having assigned responsibility by the owner/operator to design and/or reconstruct a tank.

3.32
repair
Work necessary to maintain or restore a tank to a condition suitable for safe operation. Repairs include both major repairs (see 3.25) and repairs that are not major repairs. Examples of repairs include:

a) removal and replacement of material (such as roof, shell, or bottom material, including weld metal) to maintain tank integrity;

b) re-leveling and/or jacking of a tank shell, bottom, or roof;

c) adding or replacing reinforcing plates (or portions thereof) to existing shell penetrations;

d) repair of flaws, such as tears or gouges, by grinding and/or gouging followed by welding.

3.33
repair organization
An organization that meets any of the following:

a) an owner/operator of aboveground storage tanks who repairs or alters his/her own equipment in accordance with this standard;

b) a contractor whose qualifications are acceptable to the owner/operator of aboveground storage tanks and who makes repairs or alterations in accordance with this standard;

c) one who is authorized by, acceptable to, or otherwise not prohibited by the jurisdiction, and who makes repairs in accordance with this standard.

3.34
similar service assessment
The process by which corrosion rates and inspection intervals are established for a candidate tank using corrosion rates and service history from a control tank for the purpose of establishing the next inspection date.

3.35
soil-side
The side of the tank bottom that is in contact with the ground.

3.36
storage tank engineer
One or more persons or organizations acceptable to the owner/operator who are knowledgeable and experienced in the engineering disciplines associated with evaluating mechanical and material characteristics that affect the integrity and reliability of aboveground storage tanks. The storage tank engineer, by consulting with appropriate specialists, should be regarded as a composite of all entities needed to properly assess the technical requirements.

3.37
structural discontinuity
An abrupt change in shape or cross-section that affects stress or strain distribution through the entire wall thickness.

3.38
thickened insert plate
A steel plate that replaces part of a shell plate with a nominal thickness that is greater than the nominal thickness of the adjoining material by more than 3 mm ($^1/_8$ in.).

3.39
unknown toughness
A condition that exists when it cannot be demonstrated that the material of a component satisfies the definition of recognized toughness.

SECTION 4—SUITABILITY FOR SERVICE

4.1 General

4.1.1 When the results of a tank inspection show that a change has occurred from the original physical condition of that tank, an evaluation shall be made to determine its suitability for continued use.

4.1.2 This section provides an evaluation of the suitability of an existing tank for continued service, or for a change of service, or when making decisions involving repairs, alterations, dismantling, relocating, or reconstructing an existing tank.

4.1.3 The following list of factors for consideration is not all-inclusive for all situations, nor is it intended to be a substitute for the engineering analysis and judgment required for each situation:

a) internal corrosion due to the product stored or water bottoms;

b) external corrosion due to environmental exposure;

c) stress levels and allowable stress levels;

d) properties of the stored product such as specific gravity, temperature, and corrosivity;

e) metal design temperatures at the service location of the tank;

f) external roof live load, wind, and seismic loadings;

g) tank foundation, soil, and settlement conditions;

h) chemical analysis and mechanical properties of the materials of construction;

i) distortions of the existing tank;

j) operating conditions such as filling/emptying rates and frequency.

4.1.4 API RP 571 identifies damage mechanisms in refining equipment and may be consulted for further information.

4.2 Tank Roof Evaluation

4.2.1 General

4.2.1.1 The structural integrity of the roof and roof support system shall be verified.

4.2.1.2 Roof plates corroded to an average thickness of less than 2.2 mm in any 250 mm x 250 mm (0.09 in. in any 100 in.^{2}) area or roof plates with any holes through the roof plate shall be repaired or replaced.

4.2.2 Fixed Roofs

4.2.2.1 Roof support members (rafters, girders, columns, and bases) shall be inspected for soundness by a method acceptable to the responsible inspector. Distorted (such as out-of-plumb columns), corroded, and damaged members shall be evaluated and repaired or replaced if necessary. Particular attention must be given to the possibility of severe internal corrosion of pipe columns (corrosion may not be evidenced by external visual inspection).

4.2.2.2 When a frangible roof-to-shell joint is required, evaluate for items impacting compliance with requirements under API 650, Section 5.10.2.6. Examples of some items to evaluate include tank bottom-to-shell joint corrosion or tank roof-to-shell joint modification (such as reinforcement of the joint, attachment of handrail, or other frangible joint area change).

4.2.3 Floating Roofs

4.2.3.1 Areas of roof plates and pontoons exhibiting cracks or punctures shall be repaired or the affected sections replaced. Holes through roof plates shall be repaired or replaced.

4.2.3.2 Areas that are pitted shall be evaluated to determine the likelihood of through-pitting occurring prior to the next scheduled internal inspection. If so, the affected areas shall be repaired or replaced.

4.2.3.3 Roof support systems, perimeter seal systems, appurtenances such as a roof rolling ladder, anti-rotation devices, water drain systems, and venting systems shall be evaluated for needed repairs or replacements.

4.2.3.4 Guidance for the evaluation of existing floating roofs shall be based on the criteria of API 650, Annex C, for external floating roofs, and Annex H for internal floating roofs. However, upgrading to meet this standard is not mandatory.

4.2.4 Change of Service

4.2.4.1 Internal Pressure

All requirements of the current applicable standard (e.g. API 650, Annex F) shall be considered in the evaluation and subsequent alterations to the tank roof and roof-to-shell junction.

4.2.4.2 External Pressure

As applicable, the roof support structure (if any), and the roof-to-shell junction shall be evaluated for the effects of a design partial vacuum. The criteria outlined in API 650, Annex V shall be used.

4.2.4.3 Operation at Elevated Temperature

All requirements of API 650, Annex M, shall be considered before changing the service of a tank to operation at temperatures above 93 °C (200 °F).

4.2.4.4 Operation at Lower Temperature Than Original Design

If the operating temperature is changed to a lower temperature than the original design, the requirements of the current applicable standard for the lower temperature shall be met.

4.2.4.5 Normal and Emergency Venting

4.2.4.5.1 Effects of change in operating conditions (including product service and pumping rates) on normal and emergency venting shall be considered.

4.2.4.5.2 Vents shall be inspected for proper operation and screens shall be verified to be clear of obstruction.

4.3 Tank Shell Evaluation

4.3.1 General

4.3.1.1 Flaws, deterioration, or other conditions (e.g. change of service, relocation, corrosion greater than the original corrosion allowance) that might adversely affect the performance or structural integrity of the shell of an existing tank must be evaluated and a determination made regarding suitability for intended service.

4.3.1.2 The evaluation of the existing tank shell shall be conducted by a storage tank engineer and shall include an analysis of the shell for the intended design conditions, based on existing shell plate thickness and material. The analysis shall take into consideration all anticipated loading conditions and combinations, including pressure due to fluid static head, internal and external pressure, wind loads, seismic loads, roof live loads, nozzle loads, settlement, and attachment loads.

4.3.1.3 Shell corrosion occurs in many forms and varying degrees of severity and may result in a generally uniform loss of metal over a large surface area or in localized areas. Pitting may also occur. Each case must be treated as a unique situation and a thorough inspection conducted to determine the nature and extent of corrosion prior to developing a repair procedure. Pitting does not normally represent a significant threat to the overall structural integrity of a shell unless present in a severe form with pits in close proximity to one another. Criteria for evaluating both general corrosion and pitting are defined below.

4.3.1.4 Methods for determining the minimum shell thickness suitable for continued operation are given in 4.3.2, 4.3.3, and 4.3.4 (see Section 6 for frequency of inspection).

4.3.1.5 If the requirements of 4.3.3 (welded) or 4.3.4 (riveted) cannot be satisfied, the corroded or damaged areas shall be repaired, or the allowable liquid level of the tank reduced, or the tank retired. The allowable liquid level for the continued use of a tank may be established by using the equations for a minimum acceptable thickness (see 4.3.3.1 and 4.3.4.1) and solving for height, H. The actual thickness, as determined by inspection, minus the corrosion allowance shall be used to establish the liquid level limit. The maximum design liquid level shall not be exceeded.

4.3.2 Actual Thickness Determination

4.3.2.1 For determining the controlling thicknesses in each shell course when there are corroded areas of considerable size, measured thicknesses shall be averaged in accordance with the following procedure (see Figure 4.1).

a) For each area, the authorized inspector shall determine the minimum thickness, t_2, at any point in the corroded area, excluding widely scattered pits (see 4.3.2.2).

b) Calculate the critical length, L:

In SI units: $L = 34\sqrt{Dt_2}$, but not more than 1000 millimeters

where

L is the maximum vertical length, in millimeters, over which hoop stresses are assumed to “average out” around local discontinuities;

NOTE The actual vertical length of the corroded area may exceed L.

D is the tank diameter, in meters;

t_2 is the least thickness, in millimeters, in an area of corrosion, exclusive of pits.

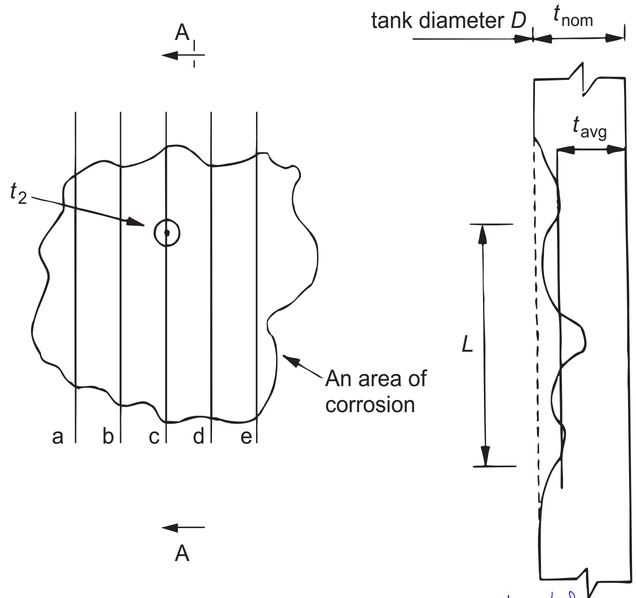
In USC units: $L = 3.7\sqrt{Dt_2}$, but not more than 40 inches

where

L is the maximum vertical length, in inches, over which hoop stresses are assumed to “average out” around local discontinuities;

NOTE The actual vertical length of the corroded area may exceed L.

D is the tank diameter, in feet;



Key

a – e are inspection planes selected by inspector.

t_2 is the least min. thickness in entire area, exclusive of pits.

SECTION A-A

Profile along Plane c , the plane having the lowest average thickness, t_1.

Procedure

1) Determine t_2

2) Calculate L

SI: $L = 34\sqrt{Dt_2}$, but not more than 1000 mm

USC: $L = 3.7\sqrt{Dt_2}$, but not more than 40 in.

3) Locate L to get minimum t_{avg}, which is t_1

Figure 4.1—Inspection of Corrosion Areas

t_2 is the least thickness, in inches, in an area of corrosion, exclusive of pits.

c) The authorized inspector shall visually or otherwise decide which vertical plane(s) in the area is likely to be the most affected by corrosion. Profile measurements shall be taken along each vertical plane for a distance, L. In the plane(s), determine the lowest average thickness, t_1, averaged over a length of L, using at least five equally spaced measurements over length L.

d) See 4.3.3.1 for minimum permitted values for t_1 and t_2. The additional loads in 4.3.3.5 shall also be considered.

e) The criteria for continued operation are as follows:

i) the value t_1 shall be greater than or equal to t_{min} (see 4.3.3 or 4.3.4), subject to verification of all other loadings listed in 4.3.3.5;

ii) the value t_2 shall be greater than or equal to 60 % of t_{min}; and

iii) any corrosion allowance required for service until the time of the next inspection shall be added to t_{min} and 60 % of t_{min}.

4.3.2.2 Widely scattered pits may be ignored provided that:

a) no pit depth results in the remaining shell thickness being less than one-half the minimum acceptable tank shell thickness exclusive of the corrosion allowance; and

b) the sum of their dimensions along any vertical line does not exceed 50 mm in any 200 mm (2 in. in an 8 in.) length (see Figure 4.2).

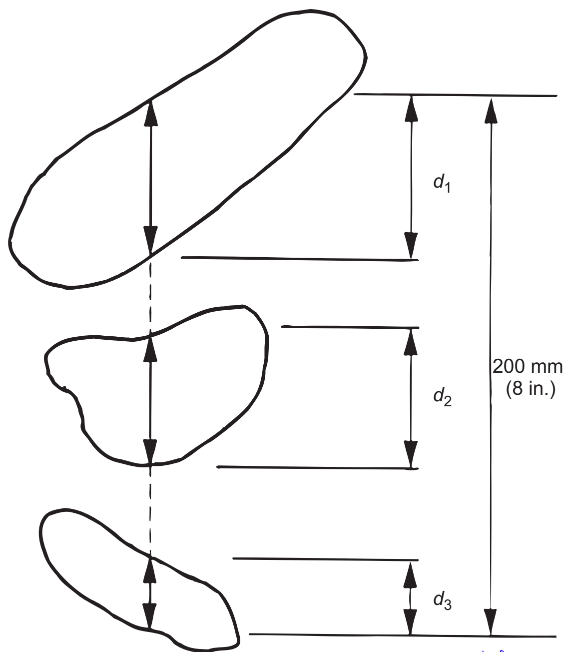


Figure 4.2—Pit Measurement

4.3.3 Minimum Thickness Calculation for Welded Tank Shell

NOTE In general, the minimum acceptable thickness (t_{min}) for an entire shell course is determined using 4.3.3.1 a) with H determined to the bottom of each shell course and the results used as a basis for judging the suitability for continued service for the tank. If locally thinned areas are identified or if specific areas are investigated (such as for a shell nozzle installation), the method of 4.3.3.1 b) may be used to complete the evaluation with H determined for that particular location.

4.3.3.1 The minimum acceptable shell plate thickness for continued service shall be determined by one or more of the methods noted herein. These methods are limited to tanks with diameters equal to 200 ft or less.

a) When determining the minimum acceptable thickness for an entire shell course, t_{min} is calculated as follows:

In SI units: $$t_{min} = \frac{4.9\,(H - 0.3)DG}{SE}$$

where

t_{min} is the minimum acceptable thickness, in millimeters for each course as calculated from the above equation; however, t_{min} shall not be less than 2.5 mm for any tank course;

D is the nominal diameter of tank, in meters;

H is the height from the bottom of the shell course under consideration to the maximum liquid level when evaluating an entire shell course, in meters; or is the height from the bottom of the length L (see 4.3.2.1) from the lowest point of the bottom of L of the locally thinned area to the maximum liquid level, in meters; or

is the height from the lowest point within any location of interest to the maximum liquid level, in meters;

G is the highest specific gravity of the contents;

S is the maximum allowable stress in MPa; use the smaller of $0.80Y$ or $0.429T$ for bottom and second course; use the smaller of $0.88Y$ or $0.472T$ for all other courses. Allowable shell stresses are shown Table 4.1 for materials listed in the current and previous editions of API 12C and API 650;

NOTE for reconstructed tanks, S shall be in accordance with the current applicable standard;

Y is the specified minimum yield strength of the plate; use 205 MPa if not known;

T is the smaller of the specified minimum tensile strength of the plate or 550 MPa; use 380 MPa if not known;

E is the original joint efficiency for the tank. Use Table 4.2 if original E is unknown. E = 1.0 when evaluating the retirement thickness in a corroded plate, when away from welds or joints by at least the greater of 25 mm or twice the plate thickness.

In USC units: $$t_{\min} = \frac{2.6\,(H-1)DG}{SE}$$

where

$t_{\min}$ is the minimum acceptable thickness, in inches for each course as calculated from the above equation; however, $t_{\min}$ shall not be less than 0.10 inch for any tank course;

D is the nominal diameter of tank, in feet;

H is the height from the bottom of the shell course under consideration to the maximum liquid level when evaluating an entire shell course, in feet; or

is the height from the bottom of the length L (see 4.3.2.1) from the lowest point of the bottom of L of the locally thinned area to the maximum liquid level, in feet; or

is the height from the lowest point within any location of interest to the maximum liquid level, in feet;

G is the highest specific gravity of the contents;

S is the maximum allowable stress in lbf/in.^{2}; use the smaller of $0.80Y$ or $0.429T$ for bottom and second course; use the smaller of $0.88Y$ or $0.472T$ for all other courses. Allowable shell stresses are shown Table 4.1 for materials listed in the current and previous editions of API 12C and API 650;

NOTE for reconstructed tanks, S shall be in accordance with the current applicable standard;

Y is the specified minimum yield strength of the plate; use 30,000 lbf/in.^{2} if not known;

T is the smaller of the specified minimum tensile strength of the plate or 80,000 lbf/in.^{2}; use 55,000 lbf/in.^{2} if not known;

E is the original joint efficiency for the tank. Use Table 4.2 if original E is unknown. E = 1.0 when evaluating the retirement thickness in a corroded plate, when away from welds or joints by at least the greater of or twice the plate thickness.

b) When determining the minimum acceptable thickness for any other portions of a shell course (such as a locally thinned area or any other location of interest), $t_{\min}$ is calculated as follows:

In SI units: $t_{\min} = \dfrac{4.9\ HDG}{SE}$

In USC units: $t_{\min} = \dfrac{2.6\ HDG}{SE}$

Table 4.1a—Maximum Allowable Shell Stresses, in SI Units (Not for Use for Reconstructed Tanks, See Note)

Material Specification	Grade	Minimum Specified Yield Stress, Y (MPa)	Minimum Specified Tensile Stress, T (MPa)	Allowable Product Stress S (MPa)		Allowable Hydrostatic Test Stress S_t (MPa)	
				Lower Two Courses	Upper Courses	Lower Two Courses	Upper Courses
A283M	C	205	380	163	179	180	185
A285M	C	205	380	163	179	180	185
A36M	—	250	400	172	189	189	208
A131M	A B	235	400	172	189	189	208
A131M	EH36	360	490	210	231	231	254
A573M	400	220	400	172	189	189	198
A573M	450	240	450	192	211	211	216
A573M	485	290	485	208	229	229	252
A516M	380	205	380	163	179	180	185
A516M	415	220	415	176	194	194	198
A516M	450	240	450	192	211	211	216
A516M	485	260	485	208	229	229	234
A662M	B	275	450	193	212	212	234
A662M	C	295	485	208	229	229	252
A537M	1	345	485	208	229	229	252
A537M	2	415	550	236	260	260	285
A663M	C D	345	485	208	229	229	252
A841M	1	345	485	208	229	229	252
—	2	415	550	236	260	260	285
A678M	A	345	485	208	229	229	252
—	B	415	550	236	260	260	285
A737M	B	345	485	208	229	229	252
A442M	380	205	380	163	179	179	185
—	415	220	415	176	194	194	198
CSA	—	—	—	—	—	—	—
G40,21M	260W	260	410	176	194	194	213
—	260WT	260	410	176	194	194	213
—	300W [g]	300	440	189	208	208	228
—	300W [h]	300	450	193	212	212	234
—	300WT [g]	300	440	189	208	208	228
—	300WT [h]	300	450	193	212	212	234

Table 4.1a—Maximum Allowable Shell Stresses, in SI Units (Not for Use for Reconstructed Tanks, See Note) (Continued)

Material Specification	Grade	Minimum Specified Yield Stress, Y (MPa)	Minimum Specified Tensile Stress, T (MPa)	Allowable Product Stress S (MPa)		Allowable Hydrostatic Test Stress S_t (MPa)	
				Lower Two Courses	Upper Courses	Lower Two Courses	Upper Courses
—	350W [g]	350	450	193	212	212	234
—	350W [h]	350	450	193	212	212	234
—	350WT [g]	350	480	206	227	227	249
—	350WT [h]	350	450	193	212	212	234
—	—	—	—	—	—	—	—
Unknown	—	NA	NA	145	145	145	145
Known	—	Y	T	[d]	[d]	[d]	[d]

NOTE Allowable stresses for reconstructed tanks are tabulated in API 650, Table 5.2a or 5.2b, or calculated per 8.4.

[a] Purposefully left blank.

[b] Purposefully left blank.

[c] Purposefully left blank.

[d] This provision is for riveted tanks, constructed of known grades of material, evaluated per 4.3.4.2. For all courses, the maximum allowable shell stress for both product and hydrostatic test conditions are listed under column for allowable product stress, S.

[e] Purposefully left blank.

[f] The allowable stresses are calculated per 4.3.3.1 and 4.3.3.2 of this standard, unless otherwise noted. The calculated allowable stresses are rounded to the nearest megapascal.

[g] These stress values are valid for CSA G40.21-04 and earlier materials.

[h] These stress values are valid for CSA G40.21-13 materials.

Table 4.1b—Maximum Allowable Shell Stresses, in USC Units (Not for Use for Reconstructed Tanks, See Note)

Material Specification and Grade	Minimum Specified Yield Stress, Y (lbf/in.^{2})	Minimum Specified Tensile Stress, T (lbf/in.^{2})	Allowable Product Stress, S (lbf/in.^{2}) [f]		Allowable Hydrostatic Test Stress S_t (lbf/in.^{2}) [f]	
			Lower Two Courses	Upper Courses	Lower Two Courses	Upper Courses
ASTM Specifications						
A283-C	30,000	55,000	23,600	26,000	26,000	27,000
A285-C	30,000	55,000	23,600	26,000	26,000	27,000
A36	36,000	58,000	24,900	27,400	27,400	30,100
A131-A, B, CS	34,000	58,000	24,900	27,400	27,400	30,100
A131-EH 36	51,000	71,000	30,500	33,500	33,500	36,800
A573-58	32,000	58,000	24,900	27,400	27,400	28,800
A573-65	35,000	65,000	27,900	30,700	30,700	31,500
A573-70	42,000	70,000	30,000	33,000	33,000	36,300
A516-55	30,000	55,000	23,600	26,000	26,000	27,000
A516-60	32,000	60,000	25,600	28,200	28,200	28,000
A516-65	35,000	65,000	27,900	30,700	30,700	31,500
A516-70	38,000	70,000	30,000	33,000	33,000	34,200
A662-B	40,000	65,000	27,900	30,700	30,700	33,700

Table 4.1b—Maximum Allowable Shell Stresses, in USC Units (Not for Use for Reconstructed Tanks, See Note) (Continued)

Material Specification and Grade	Minimum Specified Yield Stress, Y (lbf/in.^{2})	Minimum Specified Tensile Stress, T (lbf/in.^{2})	Allowable Product Stress, S (lbf/in.^{2}) [f]		Allowable Hydrostatic Test Stress S_t (lbf/in.^{2}) [f]	
			Lower Two Courses	Upper Courses	Lower Two Courses	Upper Courses
A662-C	43,000	70,000	30,000	33,000	33,000	36,300
A537-Class 1	50,000	70,000	30,000	33,000	33,000	36,300
A537-Class 2	60,000	80,000	34,300	37,800	37,800	41,500
A633-C, D	50,000	70,000	30,000	33,000	33,000	36,300
A678-A	50,000	70,000	30,000	33,000	33,000	36,300
A678-B	60,000	80,000	34,300	37,800	37,800	41,500
A737-B	50,000	70,000	30,000	33,000	33,000	36,300
A841	50,000	70,000	30,000	33,000	33,000	36,300
A10 [a]	30,000	55,000	23,600	26,000	26,000	27,000
A7 [a]	33,000	60,000	25,700	28,300	28,300	29,700
A442-55 [a]	30,000	55,000	23,600	26,000	26,000	27,000
A442-60 [a]	32,000	60,000	25,600	28,200	28,200	28,800
CSA Specifications						
G40.21, 38W	38,000	60,000	25,700	28,300	28,300	31,100
G40.21, 44W [g]	44,000	65,000	27,900	30,700	30,700	33,700
G40.21, 44W [h]	44,000	64,000	27,400	30,200	30,700	33,200
G40.21, 50W	50,000	65,000	27,900	30,700	30,700	33,700
G40.21, 50WT [g]	50,000	70,000	30,000	33,000	33,000	36,300
G40.21, 50WT [h]	50,000	65,000	27,900	30,700	30,700	33,700
Unknown Material Specification and Grade						
Unknown (Note 2)	30,000	55,00	23,600	26,000	26,000	27,000
Riveted Tanks						
A7, A9, or A10 [a] [c]	NA	NA	21,000	21,000	21,000	21,000
Known [d]	Y	T	[d]	[d]	[d]	[d]
Unknown [e]	NA	NA	21,000	21,000	21,000	21,000

NOTE Allowable stresses for reconstructed tanks are tabulated in API 650, Table 5.2a or 5.2b, or calculated per 8.4.

[a] ASTM A7, ASTM A9, ASTM A10, and ASTM A442 are obsolete ASTM material specifications previously listed in API 12C and API 650.

[b] The yield stress and tensile strength values shown are per API 653 for welded ASTM material of unknown origin.

[c] This provision is for riveted tanks, constructed of any grade of material, evaluated per 4.3.4.1.

[d] This provision is for riveted tanks, constructed of known grades of material, evaluated per 4.3.4.2. For all courses, the maximum allowable shell stress for both product and hydrostatic test conditions are listed under column for allowable product stress, S.

[e] This provision is for riveted tanks, constructed of unknown grades of material, evaluated per 4.3.4.2.

[f] The allowable stresses are calculated per 4.3.3.1 and 4.3.3.2 of this standard, unless otherwise noted. The calculated allowable stresses are rounded to the nearest 100 lbf/in.^{2}.

[g] These stress values are valid for CSA G40.21-04 and earlier materials.

[h] These stress values are valid for CSA G40.21-13 materials.

Table 4.2a—Joint Efficiencies for Welded Joints, in SI Units

Standard	Edition and Year	Type of Joint	Joint Efficiency *E*	Applicability or Limits
API 650	Seventh and Later (1980 to Present)	Butt	1.00	Basic Standard
		Butt	0.85	Annex A Spot RT
		Butt	0.70	Annex A No RT
	Third to Sixth (1966 to 1978)	Butt	0.85	Basic Standard
		Butt	1.00	Annexes D or G
	First and Second (1961 to 1964)	Butt	0.85	Basic Standard
		Butt	1.00	Annex D
API 12C	14th and 15th (1957 to 1958)	Butt	0.85	—
				—
	3rd to 13th (1940 to 1956)	Lap [a]	0.75	10 mm max. t
		Butt [c]	0.85	—
	First and Second (1936 to 1939)	Lap [a]	0.70	11 mm max. t
		Lap [b]	$0.50 + k/5$	6 mm max. t
		Butt [c]	0.85	—
Unknown	—	Lap [a]	0.70	11 mm max. t
		Lap [b]	$0.50 + k/5$	6 mm max. t
		Butt	0.70	—
		Lap [d]	0.35	—

[a] Full double lap-welded.
[b] Full fillet weld with at least 25 % intermittent full fillet opposite side; k = percent of intermittent weld expressed in decimal form.
[c] Single butt-welded joints with a back-up bar were permitted from the years of 1936 to 1940 and 1948 to 1954.
[d] Single lap-welded only.

Table 4.2b—Joint Efficiencies for Welded Joints, in USC Units

Standard	Edition and Year	Type of Joint	Joint Efficiency *E*	Applicability or Limits
API 650	Seventh and Later (1980 to Present)	Butt	1.00	Basic Standard
		Butt	0.85	Annex A Spot RT
		Butt	0.70	Annex A No RT
	Third to Sixth (1966 to 1978)	Butt	0.85	Basic Standard
		Butt	1.00	Annexes D or G
	First and Second (1961 to 1978)	Butt	0.85	Basic Standard
		Butt	1.00	Annex D

Table 4.2b—Joint Efficiencies for Welded Joints, in USC Units

Standard	Edition and Year	Type of Joint	Joint Efficiency E	Applicability or Limits
API 12C	14th and 15th (1957 to 1958)	Butt	0.85	—
				—
	3rd to 13th (1940 to 1956)	Lap [a]	0.75	3/8 in. max. t
		Butt [c]	0.85	—
	First and Second (1936 to 1939)	Lap [a]	0.70	7/16 in. max. t
		Lap [b]	0.50 + k/5	1/4 in. max. t
		Butt [c]	0.85	—
Unknown	—	Lap [a]	0.70	7/16 in. max. t
		Lap [b]	0.50 + k/5	1/4 in. max. t
		Butt	0.70	—
		Lap [d]	0.35	—

[a] Full double lap-welded.
[b] Full fillet weld with at least 25 % intermittent full fillet opposite side; k = percent of intermittent weld expressed in decimal form.
[c] Single butt-welded joints with a back-up bar were permitted from the years of 1936 to 1940 and 1948 to 1954.
[d] Single lap-welded only.

4.3.3.2 If the tank will be hydrostatically tested, the hydrostatic test height, H_t, shall be limited by one or more of the following methods. The tank shall not be filled above the level determined by the lesser value of H_t determined below.

a) After determining the controlling thickness of an entire shell course, H_t calculated as follows:

In SI units: $H_t = \dfrac{S_t E t_{\min}}{4.9D} + 0.3$

where

H_t is the height from the bottom of the shell course under consideration to the hydrostatic test height when evaluating an entire shell course in meters; or

is the height from the bottom of the length, L, (see 4.3.2.1) for the most severely thinned area in each shell course to the hydrostatic test height in meters; or

is the height from the lowest point within any other location of interest to the hydrostatic test height in meters;

S_t is the maximum allowable hydrostatic test stress in MPa; use the smaller of 0.88Y or 0.472T for bottom and second courses; use the smaller of 0.9Y or 0.519T for all other courses.

In USC units: $H_t = \dfrac{S_t E t_{\min}}{2.6D} + 1$

where

H_t is the height from the bottom of the shell course under consideration to the hydrostatic test height when evaluating an entire shell course in feet; or

is the height from the bottom of the length, L, (see 4.3.2.1) for the most severely thinned area in each shell course to the hydrostatic test height in feet; or is the height from the lowest point within any other location of interest to the hydrostatic test height in feet;

S_t is the maximum allowable hydrostatic test stress in lbf/in.^{2}; use the smaller of 0.88Y or 0.472T for bottom and second courses; use the smaller of 0.9Y or 0.519T for all other courses.

b) After determining the controlling thickness by 4.3.2.1 for a locally thinned area, or at any other location of interest within a shell course, H_t is calculated as follows:

In SI units: $H_t = \frac{S_t E t_{\min}}{4.9D}$

In USC units: $H_t = \frac{S_t E t_{\min}}{2.6D}$

NOTE 1 Depending on the specific gravity of the content used to determine $t_{\min}$, H_t may be less than H. Testing the tank to H may yield the corroded area.

NOTE 2 If H_t is less than H, owner/operator shall determine the consequence and acceptability of operating the tank to H, its maximum design liquid level. Repairs to shell sections above H_t shall comply with the requirements of 12.3.3.

NOTE 3 For reconstructed tanks, S_t shall be per the current applicable standard.

4.3.3.3 Alternatively, the minimum acceptable shell plate thickness for tanks with diameters equal to or less than 61 m (200 ft) may be calculated in accordance with the variable design point method in API 650, 5.6.4, substituting "$S \times E$" for "S"; E and S may be defined as in 4.3.3.1.

4.3.3.4 The variable design point method shall be used for tanks greater than 61 m (200 ft) in diameter, with all variables defined as in 4.3.3.1.

4.3.3.5 The thickness determinations of 4.3.3.1, 4.3.3.2, and 4.3.3.3 consider liquid loading only. All other loads shall also be evaluated according to the original standard of construction; and engineering judgment shall be used to evaluate different conditions or new information. As applicable, the following loadings shall be taken into account:

a) wind-induced buckling;

b) seismic loads;

c) operation at temperatures over 93 °C (200 °F);

d) vacuum-induced external pressure;

e) external loads caused by piping, tank-mounted equipment, hold down lugs, etc.;

f) wind-induced overturning;

g) loads due to settlement.

4.3.3.6 As an alternative to the procedures described above, any thinning of the tank shell below minimum required wall thickness due to corrosion or other wastage may be evaluated to determine the adequacy for continued service by employing the design by analysis methods defined in Section VIII, Division 2, Appendix 4 of the ASME Code; or API 579-1/ASME FFS-1, Section 4, Section 5, or Section 6, as applicable. When using the ASME criteria, the stress value used in the original tank design shall be substituted for the S_m value of Division 2, if the design stress is less than or equal to the lesser of $^2/_3Y$ (specified minimum yield strength) or $^1/_3T$ (specified minimum tensile strength). If the original design stress is greater than $^2/_3Y$ or $^1/_3T$, then the lesser of $^2/_3Y$ or $^1/_3T$ shall be substituted for S_{m}.

4.3.4 Minimum Thickness Calculation for Riveted Tank Shell

4.3.4.1 The minimum acceptable thickness for riveted tank shells shall be calculated using the equation in 4.3.3.1 except that the following allowable stress criteria and joint efficiencies shall be used:

S is 145 MPa (21,000 lbf/in.^{2});

E is 1.0 for shell plate 150 mm (6 in.) or more away from rivets. See Table 4.3 for joint efficiencies for locations within 150 mm (6 in.) of rivets.

4.3.4.2 The rivet joint efficiencies given in Table 4.3 are conservative minimums for riveted tank construction details and are included to simplify riveted tank evaluations. However, in some cases it may be advantageous to calculate the actual rivet joint efficiencies using computational methods applicable to lap and butt type riveted joints. When this alternative of calculated joint efficiencies is used, the following maximum allowable stresses shall apply:

a) for the maximum tensile stress in net section of plate, use the lesser of $0.80Y$ or $0.429T$; use 145 MPa (21,000 lbf/in.^{2}) if T or Y is unknown;

b) for the maximum shear in net section of rivet, use 110 MPa (16,000 lbf/in.^{2});

c) for the maximum bearing stress on plates or rivets, use 220 MPa (32,000 lbf/in.^{2}) for rivets in single shear, and 240 MPa (35,000 lbf/in.^{2}) for rivets in double shear.

4.3.4.3 For tanks with riveted joints, consideration shall be given to whether, and to what extent, corrosion affects such joints. If calculations show that excess thickness exists, this excess may be taken as corrosion allowance.

4.3.4.4 Non-liquid loads (see 4.3.3.5) shall also be considered in the analysis of riveted tanks.

Table 4.3—Joint Efficiencies for Riveted Joints

Type of Joint	Number of Rivet Rows	Joint Efficiency E
Lap	1	0.45
Lap	2	0.60
Lap	3	0.70
Lap	4	0.75
Butt [a]	2 [b]	0.75
Butt	3 [b]	0.85
Butt	4 [b]	0.90
Butt	5 [b]	0.91
Butt	6 [b]	0.92

[a] All butt joints listed have butt straps both inside and outside.
[b] Number of row on each side of joint center line.

4.3.5 Distortions

4.3.5.1 Shell distortions include out-of-roundness, buckled areas, flat spots, dents, and peaking and banding at welded joints.

4.3.5.2 Shell distortions can be caused by many conditions such as foundation settlement, over- or under-pressuring, high wind, poor shell fabrication, or repair techniques, and so forth.

4.3.5.3 Shell distortions shall be evaluated on an individual basis to determine if specific conditions are considered acceptable for continuing tank service and/or the extent of corrective action.

4.3.6 Flaws

Flaws such as cracks or laminations shall be thoroughly examined and evaluated to determine their nature and extent and need for repair. If a repair is needed, a repair procedure shall be developed and implemented. The requirement for repairing scars such as arc strikes, gouges, or tears from temporary attachment welds must be evaluated on a case-by-case basis. Cracks in the shell-to-bottom weld shall be removed.

4.3.7 Wind Girders and Shell Stiffeners

The evaluation of an existing tank shell for suitability for service must also consider the details and condition of any wind girders or shell stiffeners. Degradation by corrosion of these structural elements or their attachment welds to the shell may render these elements inadequate for the design conditions.

4.3.8 Shell Welds

The condition of the tank shell welds shall be evaluated for suitability for service using criteria from this standard, the as-built standard, or fitness-for-service assessment. Typical shell weld conditions are listed below with their required evaluation and/or repair actions. Repair procedures are given in 9.7.

4.3.8.1 Cracks shall be removed. Removal areas shall be evaluated and repaired if necessary.

4.3.8.2 Excessive weld reinforcement does not require rework if the tank has a satisfactory history of service. If the reinforcement will interfere with floating roof seal operation, it shall be ground as required.

4.3.8.3 Undercut of shell butt welds resulting from original construction shall not require repair if the tank has been hydrotested or will not undergo a change of service.

4.3.8.4 Weld corrosion shall be repaired if the corrosion pit cavity bottom is below the surface of the adjacent shell plate.

4.3.8.5 Shell-to-bottom weld corrosion shall be repaired if the remaining fillet is less than the required weld size.

4.3.8.6 Fillet weld size on existing nozzles shall be evaluated according to the original standard of construction.

4.3.8.7 Surface defects, such as arc strikes, shall be acceptable if the tank has been hydrotested or will not undergo a change of service.

4.3.9 Shell Penetrations

4.3.9.1 The condition and details of existing shell penetrations (nozzles, manways, cleanout openings, etc.) shall be reviewed when assessing the integrity of an existing tank shell. Details, such as type and extent of reinforcement, weld spacing, and thickness of components (reinforcing plate, nozzle neck, bolting flange, and cover plate), are important considerations and shall be reviewed for structural adequacy and compliance with the as-built standard. Existing welds on the tank shell that are not to be modified or affected by repairs and are closer than the minimum required spacings in API 650 (Seventh Edition or later) are acceptable for continued service if the welds are examined by the magnetic particle or ACFM (Alternating Current Field Measurement) methods and have no rejectable defects or indications. Grinding to eliminate weld defects is permissible if the resulting profile satisfies base thickness and weld size requirements. Weld repairs may not be used to accept weld spacings closer than permitted by API 650 (Seventh Edition or later) except as permitted by 9.11.2.7. Any other noncompliance, or deterioration due to corrosion, must be assessed and repair procedures established where appropriate or the tank re-rated, as necessary.

4.3.9.2 Nozzle wall thickness shall be evaluated for pressure and all other loads.

4.3.10 Operation at Elevated Temperatures

Tanks of welded construction that operate at elevated temperatures (exceeding 93 °C [200 °F] but less than 260 °C [500 °F]) shall be evaluated for suitability of service. The requirements of this section are based in part on the requirements of API 650, Annex M.

4.3.10.1 Continued Operation at Elevated Temperatures

4.3.10.1.1 Existing tanks that were originally designed and constructed to the requirements of API 650, Table M.1a or M.1b, shall be evaluated for continued service, as follows.

a) The tank shell shall be evaluated in conformance with 4.3.3, except that the allowable stress (S) for all shell courses shall not exceed $0.80Y$. The value of Y shall be taken as the minimum specified yield strength of the shell material multiplied by the yield strength reduction factor in of API 650, Table M.1a. When the minimum specified yield strength of the shell material is not known, the evaluation shall be based upon an assumed value of 205 MPa (30,000 lbf/in.^{2}).

b) If the bottom plate material in the critical zone has been reduced in thickness beyond the provisions of the original tank bottom corrosion allowance, if any, the shell-to-bottom joint shall be evaluated for elevated temperature, liquid head and thermal cycles. The simplified analysis technique recommended in API 650, Section M.4, may be used to satisfy this requirement.

4.3.10.1.2 Existing elevated temperature service tanks that were not originally designed and constructed to the requirements of API 650, Annex M, but have a successful service history of operation shall be evaluated for continued service as noted in 4.3.10.1.1. If the tank diameter exceeds 30 m (100 ft) and the tank was not constructed with a butt-welded annular ring, an analysis of the critical zone is required [see 4.3.10.1.1 b)]. In addition, the maximum operating temperature shall not exceed the temperatures at which the tank has operated successfully in the past.

4.3.10.2 Conversion to Operation at Elevated Temperatures

Existing tanks that were not originally designed and constructed to the requirements of API 650, Annex M shall be evaluated for a change to service to elevated temperatures as follows.

a) The tank shell shall be evaluated in conformance with API 650, Annex M. The allowable shell stresses of this standard (API 653) shall not be used.

b) The need for a butt-welded annular ring shall be determined in conformance with API 650, Annex M and installed if required.

c) The shell-to-bottom joint shall be evaluated for fatigue conditions. In addition, the adequacy of the bottom plate material in the critical zone shall be based upon the requirements of this standard.

4.4 Tank Bottom Evaluation

4.4.1 General

Tank bottom inspection strategies shall provide suitable data which, when used with the procedures in this standard, will determine the tank bottom integrity necessary to prevent leakage of fluids that may cause environmental damage. Each aspect of corrosion phenomena, and other potential leak or failure mechanism must be examined. Periodic assessment of tank bottom integrity shall be performed in addition to the internal inspections specified in 6.4. The assessment period shall be less than or equal to the appropriate internal inspection interval given in 6.4.2. The use of leak detection tests or monitoring systems (such as double bottoms or liners under tank bottoms with leak detection pipes) will satisfy the requirement for periodic assessment between internal inspections.

Excessive foundation settlement of storage tanks can affect the integrity of tank shells and bottoms. Therefore, monitoring the settlement behavior of tanks is a recognized practice to assess the integrity of tank bottoms. See Annex B for techniques for evaluating tank bottom settlement.

4.4.2 Causes of Bottom Failure

The following list gives some historical causes of tank bottom leakage or failure that shall be considered in the decision to line, repair, or replace a tank bottom:

a) internal pitting and pitting rates in the anticipated service;

b) corrosion of weld joints (weld and heat affected zone);

c) weld joint cracking history;

d) stresses placed on the bottom plates by roof support loads and shell settlement;

e) underside corrosion (normally in the form of pitting);

f) inadequate drainage resulting in surface water flowing under the tank bottom;

g) the lack of an annular plate ring when required;

h) uneven settlement that results in high localized stresses in the bottom plates;

i) roof support columns or other supports welded to the tank bottom where adequate allowance for movement was not made;

j) rock or gravel foundation pads with inadequately filled-in surface voids;

k) nonhomogeneous fill under the tank bottom (e.g. a lump of clay in a sand foundation pad);

l) inadequately supported sumps.

4.4.3 Tank Bottom Release Prevention Systems (RPSs)

API supports the use of a release prevention system (RPS) to maintain the integrity of tank bottoms. The term RPS refers to the suite of API standards and recommended practices that are designed to maintain tank integrity and thus protect the environment. With respect to tank bottoms, these include: internal inspection of the tank bottom; leak detection systems and leak testing of the tank; installing cathodic protection for the underside of the tank bottom; lining the bottom of the tank interior; providing a release prevention barrier (RPB) under the tank bottom; or some combination of these measures, depending on the operating environment and service of the tank.

4.4.3.1 Internal Inspection

Internal inspection of the tank bottom is intended to assess the current bottom integrity and identify problem conditions that may lead to future loss of integrity. Internal inspection techniques, such as bottom settlement monitoring, and considerations for determining appropriate inspection frequency, are found in 4.4.5, Section 6, Annex B, Annex C, and elsewhere.

4.4.3.2 Leak Detection Systems and Leak Testing

Tank leak detection systems and leak testing are intended to identify, quantify, and/or locate a tank bottom integrity failure that is not detectable visually or through inventory reconciliation. Leak detection may be integral to the tank design, either as constructed or as modified (e.g. RPB with interstitial monitoring) or may operate separately (e.g. soil vapor monitoring and chemical marker); may be operated by the tank owner or as a third party test or service; and may detect leaks continuously or on a periodic basis. Tank leak detection systems and testing methods are listed and discussed in API 575.

4.4.3.3 Cathodic Protection

Cathodic protection systems are intended to mitigate corrosion of steel surfaces in contact with soil, such as the underside of tank bottoms. A selection basis for cathodic protection systems is covered by API 651.

4.4.3.4 Internal Lining Protection

Internal linings and coatings for the top side of the tank bottom are intended to mitigate corrosion by providing a barrier between the tank bottom and corrosion sources. Applied linings and coatings for internal surfaces of tank bottoms are covered by API 652.

4.4.3.5 Release Prevention Barriers (RPBs)

An RPB includes steel bottoms, synthetic materials, clay liners, concrete pads, and all other barriers or combinations of barriers placed in the bottom of or under a tank, which have the function of:

1) preventing the escape of released material, and

2) containing or channeling released material for leak detection.

RPB design is covered in detail in Annex I of API 650. Replacement of tank bottoms is covered in 9.11.2.

If a decision is made to replace an existing bottom, API supports the evaluation of installing an RPB or continued use of an RPS. The evaluation should consider the effectiveness of other RPS controls, the product stored, the location of the tank, and environmental sensitivities.

4.4.4 Bottom Plate Thickness Measurements

Various methods for determining tank bottom plate soil-side corrosion are available. The methods vary to the extent by which they can reliably measure general corrosion and pitting. A combination of these methods may be required along with extrapolation techniques and analysis to establish the probable conditions of the entire tank bottom. Magnetic flux leakage (MFL) tools are commonly used, along with ultrasonic (UT) thickness measurement tools, to examine tank bottoms. Ultrasonic thickness measurement techniques are often used to confirm and further quantify data obtained by MFL examination, but these techniques may not be required depending on the specific procedure and application. The quality of data obtained from both MFL and ultrasonic thickness techniques is dependent on personnel, equipment and procedures. Annex G may be used to provide guidance in qualifying personnel and procedures for obtaining thickness data.

4.4.5 Minimum Thickness for Tank Bottom Plate

Quantifying the minimum remaining thickness of tank bottoms based on the results of measurement can be done by the method outlined in 4.4.5.1. Other approaches such as the probabilistic method in 4.4.5.2 may be used.

4.4.5.1 An acceptable method for calculating the minimum acceptable bottom thickness for the entire bottom or portions thereof is as follows:

$$MRT = (\text{Minimum of } RT_{bc} \text{ or } RT_{ip}) - O_r\,(StP_r + UP_r)$$

where

MRT is the minimum remaining thickness at the end of interval O_r. This value must meet the requirements of Table 4.4, 4.4.5.4, and 4.4.6;

O_r is the in-service interval of operation (years to next internal inspection) not to exceed that allowed by 6.4.2;

RT_{bc} is the minimum remaining thickness from bottom side corrosion after repairs;

RT_{ip} is the minimum remaining thickness from internal corrosion after repairs;

StP_r is the maximum rate of corrosion not repaired on the top side. $StP_r = 0$ for coated areas of the bottom. The expected life of the coating must equal or exceed O_r to use $StP_r = 0$;

UP_r is the maximum rate of corrosion on the bottom side. To calculate the corrosion rate, use the minimum remaining thickness after repairs. Assume a linear rate based on the age of the tanks. $UP_r = 0$ for areas that have effective cathodic protection.

NOTE 1 For areas of a bottom that have been scanned by the magnetic flux leakage (or exclusion) process, and do not have effective cathodic protection, the thickness used for calculating UP_r must be the lesser of the MFL threshold or the minimum thickness of corrosion areas that are not repaired. The MFL threshold is defined as the minimum remaining thickness to be detected in the areas examined. This value should be predetermined by the tank owner based on the desired inspection interval.

Areas of bottom side corrosion that are repaired should be evaluated with the corrosion rate for the repaired area unless the cause of corrosion has been removed. The evaluation is done by using the corrosion rate of the repaired area for UP_r, and adding the patch plate (if used) thickness to the term "minimum of RT_{bc} or RT_{ip}."

NOTE 2 Corrosion of the bottom plate includes loss of metal from isolated or general corrosion.

4.4.5.2 For the probabilistic method, a statistical analysis is made of thickness data from measurements (see 4.4.4) projecting remaining thickness, based on sample scanning of the bottom.

4.4.5.3 If the minimum bottom thicknesses, at the end of the in-service period of operation, are calculated to be less than the minimum bottom renewal thicknesses given in Table 4.4, or less than the minimum bottom renewal thicknesses providing acceptable risk as determined by an RBI assessment per 6.4.2.2.2, the bottom shall be lined, repaired, replaced, or the interval to the next internal inspection shortened.

Table 4.4a—Bottom Plate Minimum Thickness, in SI Units

Minimum Bottom Plate Thickness at Next Inspection (mm)	**Tank Bottom/ Foundation Design**
2.54	Tank bottom/foundation design with no means for detection and containment of a bottom leak
1.27	Tank bottom/foundation design with means to provide detection and containment of a bottom leak
1.27	Applied tank bottom reinforced lining, > 1.27 mm thick, in accordance with API 652

Table 4.4b—Bottom Plate Minimum Thickness, in USC Units

Minimum Bottom Plate Thickness at Next Inspection (in.)	**Tank Bottom/ Foundation Design**
0.10	Tank bottom/foundation design with no means for detection and containment of a bottom leak.
0.05	Tank bottom/foundation design with means to provide detection and containment of a bottom leak.
0.05	Applied tank bottom reinforced lining, > 0.05 in. thick, in accordance with API 652.

4.4.5.4 Unless a stress analysis is performed, the minimum bottom plate thickness in the critical zone of the tank bottom defined in 3.10 shall be the smaller of 3 mm (0.118 in.) (one-half the API 650-required bottom plate thickness not including corrosion allowance) or 50 % of t_{min} of the lower shell course per 4.3.3.1 but not less than 2.5 mm (0.10 in.) at the next inspection. Averaging of the bottom thickness is not permitted.

The structural integrity of the tank bottom critical zone may not be affected by isolated pitting and isolated corroded areas. For these critical zone areas, the minimum thickness at the next internal inspection may be determined by Table 4.4 or where an RBI assessment per 6.4.2.2.2 has been utilized.

The storage tank engineer shall determine if the isolated pitting and isolated corroded areas affect the tank bottom critical zone structural integrity. This may involve performing an engineering evaluation (see 4.3.3.6 for guidance) to verify that the structural integrity will be adequate until the next internal inspection.

4.4.5.5 The repair of product-side or soil-side corrosion, when performed to extend the in-service period of operation, shall be by pit welding, overlay welding, or welded-on lap patching per 9.7 or 9.11, followed by inspection and testing. The extent of weld repairs is limited in the critical zone in accordance with 9.11.1.2.

4.4.5.6 The treatment of bottom corrosion by the use of non-welded repairs (e.g. coatings, caulking, epoxies, bolting) shall not be used to increase RT_{ip} or RT_{bc} for calculating MRT.

4.4.5.7 Unless a stress analysis is performed that considers future corrosion until the time it can be inspected, repaired, or replaced, the following criteria applies:

— the thickness of the projection of the bottom plate beyond the shell as measured at the toe of the outside bottom-to-shell fillet weld shall not be less than 2.5 mm (0.10 in.), and

— the projection of the bottom plate beyond the outside toe of the shell-to-bottom weld shall be at least 10 mm ($^3/_8$ in.).

4.4.6 Minimum Thickness for Annular Plate Ring

4.4.6.1 Due to strength requirements, the minimum thickness of annular plate ring is usually greater than 0.10 in. Isolated pitting will not appreciably affect the strength of the plate. Unless a stress analysis is performed, the annular plate thickness shall be in accordance with 4.4.6.2 or 4.4.6.3, as applicable.

4.4.6.2 For tanks in service with a product specific gravity less than 1.0, which require annular plates for other than seismic loading considerations, the thickness of the annular plates shall be not less than the thicknesses given in Table 4.5, plus any specified corrosion allowance. Interpolation is allowed within Table 4.5 based on shell stress determined per Note b of Table 4.5.

4.4.6.3 For tanks in service with a product specific gravity of 1.0 or greater, which require annular plates for other than seismic loading considerations, the thickness of the annular plates shall be in accordance with API 650, Table 5.1a or 5.1b, plus any specified corrosion allowance. Interpolation is allowed within API 650, Table 5.1a or 5.1b based on shell stress determined per Note b of API 650, Table 5.1.

4.4.6.4 For tanks that utilize thickened annular plates for seismic considerations, a seismic evaluation shall be performed in accordance with the requirements of the as built standard, using the actual thickness of the existing annular plate.

4.4.6.5 For the thickness and projection of the annular plate beyond the shell, see 4.4.5.7.

4.5 Tank Foundation Evaluation

4.5.1 General

Table 4.5a—Annular Bottom Plate Thicknesses (Product Specific Gravity < 1.0), in SI Units

Plate Thickness [a] of First Shell Course (mm)	Stress [b] in First Shell Course (MPa)			
	< 168	< 186	< 205	< 223
$t \leq 19$	4.32	5.08	5.84	7.62
$19 < t \leq 25$	4.32	5.59	7.88	9.65
$25 < t \leq 32$	4.32	6.60	9.65	12.19
$32 < t \leq 38$	5.59	8.64	11.94	14.99
$t > 38$	6.86	10.16	13.46	17.27

NOTE The thicknesses specified in the table are based on the foundation providing a uniform support under the full width of the annular plate. Unless the foundation is properly compacted, particularly at the inside of a concrete ringwall, settlement will produce additional stresses in the annular plate.

[a] Plate thickness refers to the tank shell as constructed.
[b] Stresses are calculated from $[2.34D\,(H - 1)]/t$ (USC formula).

Table 4.5b—Annular Bottom Plate Thicknesses (Product Specific Gravity < 1.0), in USC Units

Plate Thickness [a] of First Shell Course (in.)	Stress [b] in First Shell Course (lbf/in.^{2})			
	< 24,300	< 27,000	< 29,700	< 32,400
$t \leq 0.75$	0.17	0.20	0.23	0.30
$0.75 < t \leq 1.00$	0.17	0.22	0.31	0.38
$1.00 < t \leq 1.25$	0.17	0.26	0.38	0.48
$1.25 < t \leq 1.50$	0.22	0.34	0.47	0.59
$t > 1.50$	0.27	0.40	0.53	0.68

NOTE The thicknesses specified in the table are based on the foundation providing a uniform support under the full width of the annular plate. Unless the foundation is properly compacted, particularly at the inside of a concrete ringwall, settlement will produce additional stresses in the annular plate.

[a] Plate thickness refers to the tank shell as constructed.
[b] Stresses are calculated from $[2.34D\,(H - 1)]/t$.

4.5.1.1 The principal causes of foundation deterioration are settlement, erosion, cracking, and deterioration of concrete initiated by: calcining, attack by underground water, attack by frost, and attack by alkalies and acids. To ensure suitability for service, all tank foundations shall be inspected periodically (see 6.3).

4.5.1.2 Some mechanisms of concrete deterioration are briefly described below.

a) Calcining (loss of water of hydration) can occur when concrete has been exposed to sufficiently high temperature for a period of time. During intermediate cooling periods, the concrete can absorb moisture, swell, lose its strength, and crack.

b) Deterioration of concrete exposed to underground water can be caused by chemical attack, by cyclic changes in temperature, and by freezing moisture.

c) Expansion of freezing moisture in porous concrete, or in concrete with minor settlement cracks or temperature cracks, can result in spalling and/or the development of serious structural cracks.

d) Sulfate-type alkalies, and to a lesser extent, chlorides, can act corrosively to destroy the bond of the concrete.

e) Temperature cracks (hairline cracks of uniform width) do not seriously affect the strength of the concrete foundation structure; however, these cracks can be potential access points for moisture or water seepage that could eventually result in corrosion of the reinforcing steel.

4.5.1.3 When a tank is to be used in elevated temperature (> 93 °C [200 °F]) service, the provisions of API 650, Section B.6 shall be considered in the evaluation of the suitability for service of the tank foundation.

4.5.2 Foundation Repair or Replacement

4.5.2.1 If there is a need for foundation replacement or installation, the new foundation elevation profile must meet the tolerance in 10.5.6. Alternatively, if the new foundation is to be constructed up to the bottom, changing the levelness of the tank is not required if reviewed and approved by a storage tank engineer considering the plumbness of the shell, presence, or absence of shell distortion, and original construction levelness which warrant leaving the tank at the current state of levelness.

4.5.2.2 Concrete pads, ringwalls, and piers, showing evidence of spalling, structural cracks, or general deterioration, shall be repaired to prevent water from entering the concrete structure and corroding the reinforcing steel.

4.5.3 Anchor Bolts

Distortion of anchor bolts and excessive cracking of the concrete structures in which they are embedded may be indications of either serious foundation settlement or a tank overpressure uplift condition.

SECTION 5—BRITTLE FRACTURE CONSIDERATIONS

5.1 General

This section provides a procedure for the assessment of existing tanks for suitability for continued operation or change of service with respect to the risk of brittle fracture and does not supplement or replace the requirements of Section 12 for the examination and testing for the hydrostatic testing of repaired, modified, or reconstructed tanks. The procedure applies to both welded and riveted tanks; however, the procedure is based primarily on experience and data obtained from welded tanks.

5.2 Basic Considerations

5.2.1 A decision tree (see Figure 5.1) is used to present the assessment procedure for failure due to brittle fracture. The decision tree is based on the following principles.

5.2.2 In all reported incidents of tank failure due to brittle fracture, failure occurred either shortly after erection during hydrostatic testing or on the first filling in cold weather, after a change to lower temperature service, or after a repair/alteration. This experience shows that once a tank has demonstrated the ability to withstand the combined effects of maximum liquid level (highest stresses) and lowest operating temperature without failing, the risk of failure due to brittle fracture with continued service is minimal.

5.2.3 Any change in service must be evaluated to determine if it increases the risk of failure due to brittle fracture. In the event of a change to a more severe service (such as operating at a lower temperature or handling product at a higher specific gravity) it is necessary to consider the need for a hydrostatic test to demonstrate fitness for a new more severe service. The following aspects should be considered:

a) the likelihood of repairs/alterations since the original hydrostatic test not meeting requirements of this standard;

b) deterioration of the tank since original hydrostatic test.

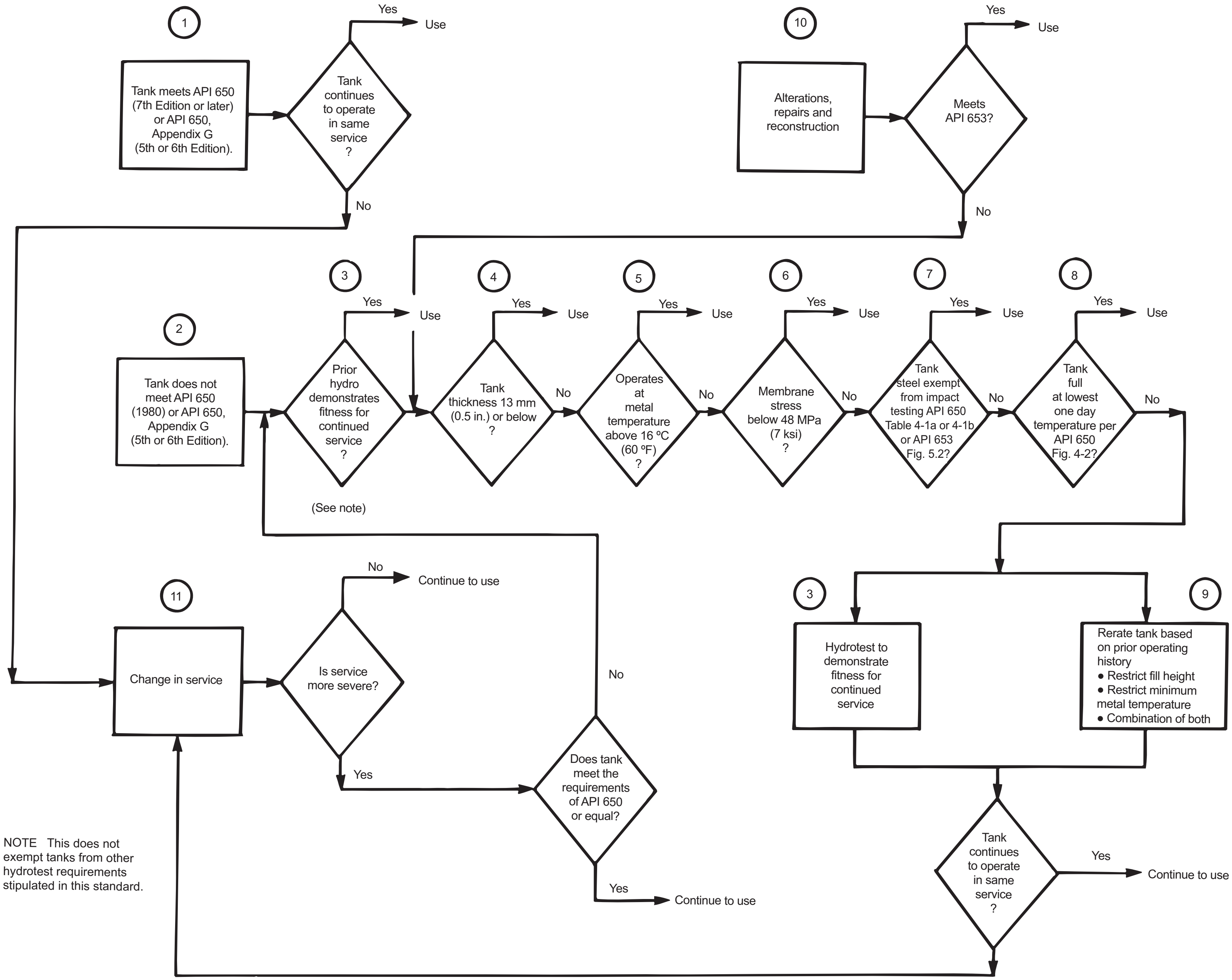
5.3 Assessment Procedure

5.3.1 The assessment procedure illustrated in Figure 5.1 shall be used. Each of the key steps, numbered 1 through 11 on the decision tree, correspond sequentially to the explanations provided below.

5.3.2 *Step 1*—The tank meets the requirements of API 650 (Seventh Edition or later) or API 650, Appendix G (Fifth and Sixth Editions) to minimize the risk of failure due to brittle fracture. Alternatively, tanks may also be shown to meet the toughness requirements of API 650 (Seventh Edition or later) by impact testing coupon samples from a representative number of shell plates.

5.3.3 *Step 2*—Many tanks that continue to operate successfully in the same service were not built to the requirements of API 650 (see editions and appendices named in 5.3.2). These tanks are potentially susceptible to failure due to brittle fracture and require an assessment as illustrated by the decision tree.

5.3.4 *Step 3*—For the purpose of this assessment, hydrostatic testing demonstrates fitness for continued service with minimal risk of failure due to brittle fracture, provided that all governing requirements for repairs, alterations, reconstruction, or change in service are in accordance with this standard (including a need for hydrostatic testing after major repairs, major alterations or reconstruction). The effectiveness of the hydrostatic test in demonstrating fitness for continued service is shown by industry experience.



NOTE This does not exempt tanks from other hydrotest requirements stipulated in this standard.

Figure 5.1—Brittle Fracture Considerations

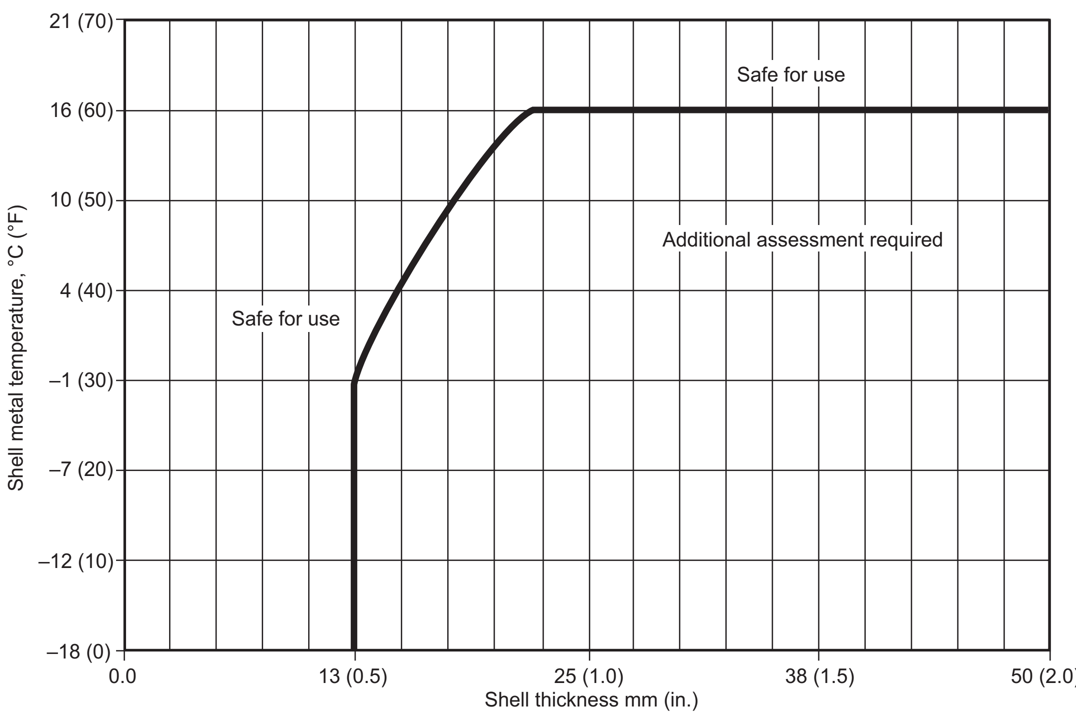
5.3.5 *Step 4*—If a tank shell thickness is no greater than 13 mm (0.5 in.), the risk of failure due to brittle fracture is minimal, provided that an evaluation for suitability of service in accordance with Section 4 has been performed. The original nominal thickness for the thickest tank shell plate shall be used for this assessment.

5.3.6 *Step 5*—No known tank failures due to brittle fracture have occurred at shell metal temperatures of 16 °C (60 °F) or above. Similar assurance against brittle fracture can be gained by increasing the metal temperature by heating the tank contents.

5.3.7 *Step 6*—Industry experience and laboratory tests have shown that a membrane stress in tank shell plates of at least 48 MPa (7 ksi) is required to cause failure due to brittle fracture.

5.3.8 *Step 7*—Tanks constructed from steels listed in Figures 4.1a or 4.1b of API 650 can be used in accordance with their exemption curves, provided that an evaluation for suitability of service in conformance with Section 4 of this standard has been performed. Additionally, tanks constructed in accordance with another nationally recognized code or standard containing toughness rules (such as API 620) may be used in accordance with the current toughness rules of that standard. Tanks fabricated from steels of unknown material specifications, thicker than 13 mm ($^1/_2$ in.) and operating at a shell metal temperature below 16 °C (60 °F), can be used if the tank meets the requirements of Figure 5.2. The original nominal thickness for thickest tank shell plate shall be used for the assessment. For unheated tanks, the shell metal temperature shall be the design metal temperature as defined in API 650, Section 3.6.

5.3.9 *Step 8*—The risk of failure due to brittle fracture is minimal once a tank has demonstrated that it can operate at a specified maximum liquid level at the lowest expected temperature without failing. For the purpose of this assessment, the lowest expected temperature is defined as the lowest one-day mean temperature as shown in API 650, Figure 4.2. It is necessary to check tank log records and meteorological records to ensure that the tank had operated at the specified maximum liquid level when the 1-day mean temperature was as low as shown in API 650, Figure 4.2.



NOTE For unheated tanks, the shell metal temperature shall equal the design metal temperature as defined in API 650, Section 3.4. The original nominal thickness for the thickest tank shell plate shall be used for the assessment.

Figure 5.2—Exemption Curve for Tanks Constructed from Carbon Steel of Unknown Material Specification

5.3.10 *Step 9*—An evaluation can be performed to establish a safe operating envelope for a tank based on the operating history. This evaluation shall be based on the most severe combination of temperature and liquid level experienced by the tank during its life. The evaluation may show that the tank needs to be re-rated or operated differently; several options exist:

a) restrict the liquid level;

b) restrict the minimum metal temperature;

c) change the service to a stored product with a lower specific gravity;

d) combinations of Items a), b), and c), above.

The owner/operator can also make a more rigorous analysis to determine the risk of failure due to brittle fracture by performing a fracture mechanics analysis based on established principles and practices. The procedures and acceptance criteria for conducting an alternative analysis are not included in this standard.

5.3.11 *Step 10*—All repairs, alterations, and relocations shall be made in compliance with this standard.

5.3.12 *Step 11*—An assessment shall be made to determine if the change in service places the tank at greater risk of failure due to brittle fracture. The service can be considered more severe and create a greater risk of brittle fracture if the service temperature is reduced (e.g. changing from heated oil service to ambient temperature product), or the product is changed to one with a greater specific gravity and thus increased stresses.

SECTION 6—INSPECTION

6.1 General

Periodic in-service inspection of tanks shall be performed as defined herein. The purpose of this inspection is to assure continued tank integrity. Inspections, other than those defined in 6.3 shall be directed by an authorized inspector.

6.2 Inspection Frequency Considerations

6.2.1 Several factors must be considered to determine inspection intervals for storage tanks. These include, but are not limited to, the following:

a) the nature of the product stored;

b) the results of visual maintenance checks;

c) corrosion allowances and corrosion rates;

d) corrosion prevention systems;

e) conditions at previous inspections;

f) the methods and materials of construction and repair;

g) the location of tanks, such as those in isolated or high risk areas;

h) the potential risk of air or water pollution;

i) leak detection systems;

j) change in operating mode (e.g. frequency of fill cycling, frequent grounding of floating roof support legs);

k) jurisdictional requirements;

l) changes in service (including changes in water bottoms);

m) the existence of a double bottom or a release prevention barrier.

6.2.2 The interval between inspections of a tank (both internal and external) should be determined by its service history unless special reasons indicate that an earlier inspection must be made. A history of the service of a given tank or a tank in similar service (preferably at the same site) should be available so that complete inspections can be scheduled with a frequency commensurate with the corrosion rate of the tank. On-stream, nondestructive examination methods shall be considered when establishing inspection frequencies.

6.2.3 Jurisdictional regulations, in some cases, control the frequency and interval of the inspections. These regulations may include vapor loss requirements, seal condition, leakage, proper diking, and repair procedures. Knowledge of such regulations is necessary to ensure compliance with scheduling and inspection requirements.

6.3 Inspections from the Outside of the Tank

6.3.1 Routine In-service Inspections

6.3.1.1 The external condition of the tank shall be monitored by close visual inspection from the ground on a routine basis. This inspection may be done by owner/operator personnel, and can be done by other than authorized inspectors as defined in 3.4. Personnel performing this inspection should be knowledgeable of the storage facility operations, the tank, and the characteristics of the product stored.

6.3.1.2 The interval of such inspections shall be consistent with conditions at the particular site, but shall not exceed one month.

6.3.1.3 This routine in-service inspection shall include a visual inspection of the tank's exterior surfaces. Evidence of leaks; shell distortions; signs of settlement; corrosion; and condition of the foundation, paint coatings, insulation systems, and appurtenances should be documented for follow-up action by an authorized inspector.

6.3.2 External Inspection

6.3.2.1 All tanks shall be given a visual external inspection by an authorized inspector. This inspection shall be called the external inspection and must be conducted at least every five years or $RCA/4N$ years (where RCA is the difference between the measured shell thickness and the minimum required thickness in mm [mils, 0.001 in.] and N is the shell corrosion rate in mm [mils, 0.001 in.] per year), whichever is less. Tanks may be in operation during this inspection.

6.3.2.2 Insulated tanks need to have insulation removed only to the extent necessary to determine the condition of the exterior wall of the tank or the roof.

6.3.2.3 Tank grounding system components such as shunts or mechanical connections of cables shall be visually checked. Recommended practices dealing with the prevention of hydrocarbon ignition are covered by API 2003.

6.3.3 Ultrasonic Thickness Inspection

6.3.3.1 External, ultrasonic thickness measurements of the shell can be a means of determining a rate of uniform general corrosion while the tank is in service, and can provide an indication of the integrity of the shell. The extent of such measurements shall be determined by the owner/operator.

6.3.3.2 When used, the ultrasonic thickness measurements shall be made at intervals not to exceed the following.

a) When the corrosion rate is not known, the maximum interval shall be five years. Corrosion rates may be estimated from tanks in similar service based on thickness measurements taken at an interval not exceeding five years.

b) When the corrosion rate is known, the maximum interval shall be the smaller of $RCA/2N$ years (where RCA is the difference between the measured shell thickness and the minimum required thickness in mm [mils, 0.001 in.] and N is the shell corrosion rate in mm [mils, 0.001 in.] per year) or 15 years.

6.3.3.3 Internal inspection of the tank shell, when the tank is out of service, can be substituted for a program of external ultrasonic thickness measurement if the internal inspection interval is equal to or less than the interval required in 6.3.3.2 b).

6.3.4 Cathodic Protection Surveys

6.3.4.1 Where exterior tank bottom corrosion is controlled by a cathodic protection system, periodic surveys of the system shall be conducted in accordance with API 651. The owner/operator shall review the survey results.

6.3.4.2 The owner/operator shall assure competency of personnel performing surveys.

6.4 Internal Inspection

6.4.1 General

6.4.1.1 Internal inspection is primarily required to do as follows.

a) Ensure that the bottom is not severely corroded and leaking.

b) Gather the data necessary for the minimum bottom and shell thickness assessments detailed in Section 4. As applicable, these data shall also take into account external ultrasonic thickness measurements made during in-service inspections (see 6.3.3).

c) Identify and evaluate any tank bottom settlement.

6.4.1.2 All tanks shall have a formal internal inspection conducted at the intervals defined by 6.4.2. The authorized inspector shall supervise or conduct a visual examination and assure the quality and completeness of the nondestructive examination (NDE) results. If the internal inspection is required solely for the purpose of determining the condition and integrity of the tank bottom, the internal inspection may be accomplished with the tank in-service utilizing various ultrasonic robotic thickness measurement and other on-stream inspection methods capable of assessing the thickness of the tank bottom, in combination with methods capable of assessing tank bottom integrity as described in 4.4.1. Electromagnetic methods may be used to supplement the on-stream ultrasonic inspection. If an in-service inspection is selected, the data and information collected shall be sufficient to evaluate the thickness, corrosion rate, and integrity of the tank bottom and establish the internal inspection interval, based on tank bottom thickness, corrosion rate, and integrity, utilizing the methods included in this standard.

6.4.2 Inspection Intervals

Initial and subsequent inspection intervals shall be in compliance with the requirements of 6.4.2.1 and 6.4.2.2.

For existing tanks, tank owner/operators shall review the internal inspection interval and be in compliance with this section within 5 years from date of first publication of API 653, Fourth Edition, Addendum 2, January 2012.

6.4.2.1 Initial Internal Inspection Interval

The initial internal inspection intervals for newly constructed tanks or existing tanks with a newly installed bottom shall be established either per 6.4.2.1.1 or 6.4.2.1.2. Alternatively, the next internal inspection interval for existing tanks where a new bottom has been installed may be determined per 6.4.2.2, if all the following conditions are satisfied.

a) Inspection data has been obtained from the previous tank bottom.

b) Inspection data obtained is deemed applicable to the new tank bottom or corrosion rates (product or soil side) for the new tank bottom are not expected to be greater than the corrosion rates of the previous tank bottom.

c) Corrosion rate applicability to the new tank bottom shall be verified by a storage tank engineer experienced in materials or corrosion or by consulting with appropriate specialist.

d) The owner/operator shall agree and follow the guidelines in 6.4.2.2 in order to use the subsequent internal inspection interval as the next inspection interval for the new tank bottom.

6.4.2.1.1 The interval from initial service date until the first internal inspection shall not exceed 10 years unless a tank has one or more of the leak prevention, detection, corrosion mitigation, or containment safeguards listed in Table 6.1. The maximum initial internal inspection interval shall be based on 10 years plus incremental credits for the additional safeguards in Table 6.1, which are cumulative.

The initial internal inspection interval shall not exceed 20 years for tanks without a Release Prevention Barrier, or 30 years for tanks with a Release Prevention Barrier.

The limits of Table 4.4 do not apply when establishing the initial internal inspection interval in accordance with Section 6.4.2.1.1 and Table 6.1.

Table 6.1—Tank Safeguard

Tank Safeguard	Add to Initial Interval
i. Installation of thick-film reinforced lining of the product-side of the tank bottom, installed per API RP 652.	5 yrs
ii. Application of an internal thin-film or a thick-film unreinforced lining as installed per API RP 652.	2 yrs
iii. Cathodic protection of the soil-side of the tank bottom installed, maintained, and inspected per API RP 651.	5 yrs
iv. Release prevention barrier installed per API 650, Annex I.	10 yrs
v. Initial bottom thickness > 6.0 mm (0.25 in.)	[Initial bottom thickness – 6.0 mm (0.25 in.)]/corrosion rate*
vi. Bottom constructed from stainless steel material that meets requirements of API 650, Annex SC, and either Annex S or Annex X; and internal and external environments have been determined by a qualified corrosion specialist to present very low risk of cracking or corrosion failure.	10 yrs
* Corrosion rate to be 0.375 mm per year (15 mpy), or as determined from Annex H, Similar Service.	

For example, the maximum initial internal inspection interval for an 8 mm ($^5/_{16}$ in.) thick bottom that has a release prevention barrier and a fiberglass-reinforced lining would be determined as follows:

Credit for initial bottom thickness > 6 mm = (8 mm – 6 mm) /0.375 mm per year = 5.2 years

Credit for initial bottom thickness > 0.25 in. = (0.3125 in. – 0.25 in.) / 0.015 in. per year = 4.2 years

Maximum initial internal inspection interval = 10 years (initial) + 5 years (fiberglass-reinforced lining) + 10 years (release prevention barrier) + 4.2 years (credit for initial bottom thickness > 0.25 in.) = 29.2 years.

NOTE ¼ in. bottom is 6.35 mm, although 6 mm plate is typically used for tank bottom installations. The difference in rounding results in the two different answers above.

6.4.2.1.2 As an alternative to establishing the initial interval in accordance with 6.4.2.1 and Table 6.1, the initial internal inspection date and reassessment can be established using Risk Based Inspection (RBI) assessment per 6.4.2.2.2.

These assessments may establish an initial inspection interval exceeding 10 years but shall not exceed 20 years for tanks without a Release Prevention Barrier, or 30 years for tanks with a Release Prevention Barrier except as follows.

If an RBI assessment has been performed, the maximum initial internal inspection interval does not apply to tanks storing the following.

1) Highly viscous substances which solidify at temperatures below 43 °C (110 °F), (some examples of these substances are: asphalt, roofing flux, residuum, vacuum bottoms and reduced crude), or;

2) Any substance or mixture that is:

   a) not identified or regulated either as a hazardous chemical or material under the applicable laws of the jurisdiction; and

   b) that the owner/operator has determined will not adversely impact surface or groundwater beyond the facility or affect human health or the environment.

6.4.2.2 Subsequent Internal Inspection Interval

The interval between subsequent internal inspections shall be determined in accordance with either the corrosion rate procedures of 6.4.2.2.1 or the risk based inspection procedures as outlined in 6.4.2.2.2.

6.4.2.2.1 The subsequent inspection interval (beyond the initial inspection) can be determined using the measured tank bottom corrosion rate and the minimum remaining thickness in accordance with 4.4.5. During any examination to determine corrosion rates the owner/operator should ensure they understand the effectiveness of the inspection techniques employed for detecting and measuring potential damage mechanisms.

When changing service, an owner/operator may decide to use internal corrosion rates obtained from similar service assessment (performed per Annex H) when setting subsequent internal inspection dates.

When using the corrosion rate procedures of 6.4.2.2.1 the maximum subsequent internal inspection interval shall be 20 years for tanks without a Release Prevention Barrier, or 30 years for tanks with a Release Prevention Barrier.

6.4.2.2.2 An owner/operator can establish the subsequent internal inspection interval using risk based inspection (RBI) procedures in accordance with API RP 580 and the additional requirements of this section.

The results of the RBI assessment shall be used to establish a tank inspection strategy that defines the most appropriate inspection methods, appropriate frequency for internal, external and in-service inspections, and prevention and mitigation steps to reduce the likelihood and consequence of tank leakage or failure.

An RBI assessment shall consist of a systematic evaluation of both the likelihood of failure and the associated consequences of failure, in accordance with API RP 580. The RBI assessment shall be thoroughly documented, clearly defining all factors contributing to both likelihood and consequence of tank leakage or failure.

The RBI assessment shall be performed by a team including inspection and engineering expertise knowledgeable in the proper application of API RP 580 principles, tank design, construction, and modes of deterioration. The RBI assessment shall be reviewed and approved by a team as above at intervals not to exceed 10 years or more often if warranted by process, equipment, or consequence changes.

The applied RBI methodology (not every individual assessment) shall have a documented validation review to demonstrate that it has all the key elements defined in API RP 580 and this section. The validation should be performed by an entity external to the RBI assessment team.

If corrosion rates are based on prior inspections, they shall be derived from either high or medium inspection effectiveness as defined by the owner/operator procedures. Refer to API RP 581 for examples of high and medium inspection effectiveness. Corrosion rates from low inspection effectiveness such as spot UT shall not be used in the RBI process.

A tank shall be removed from service when the risk exceeds the acceptable risk criteria established per the owner/operator procedure.

NOTE API does not recommend running tank bottoms to failure, or operating tanks indefinitely with known or suspected bottom leaks.

6.4.2.2.2.1 Likelihood factors that shall be evaluated in tank RBI assessments, in addition to the likelihood factors in API RP 580 include, but are not limited to, the following:

a) original thickness, weld type, and age of bottom plates;

b) analysis methods used to determine the product-side, soil-side and external corrosion rates for both shell and bottom and the accuracy of the methods used;

c) inspection history, including tank failure data;

d) soil resistivity;

e) type and design quality of tank pad/cushion including quality control at construction;

f) water drainage from berm area;

g) type/effectiveness of cathodic protection system and maintenance history;

h) operating temperatures;

i) effects on internal corrosion rates due to product service;

j) internal coating/lining/liner type, age and condition;

k) use of steam coils and water draw-off details;

l) quality of tank maintenance, including previous repairs and alterations;

m) design codes and standards and the details utilized in the tank construction, repair, and alteration (including tank bottoms);

n) materials of construction;

o) effectiveness of an inspection includes examination methods and scope which are to be determined by the inspector;

p) functional failures, such as floating roof seals, roof drain systems, etc.;

q) settlement data;

r) quality assurance/control during tank construction, including pad cleanliness, slope of bottom, foundation installation, document/records to show how the tank was built, etc.

6.4.2.2.2.2 Consequence factors that shall be evaluated in tank RBI assessments include, but are not limited to, the following:

a) tank bottom with a Release Prevention Barrier (RPB) details (single, double, RPB, internal reinforced linings, etc.);

b) product type and volume;

c) mode of failure, (i.e. slow leak to the environment, tank bottom rupture or tank shell brittle fracture);

d) identification of environmental receptors such as wetlands, surface waters, ground waters, drinking water aquifers, and bedrock;

e) distance to environmental receptors;

f) effectiveness of leak detection systems and time to detection;

g) mobility of the product in the environment, including, for releases to soil, product viscosity and soil permeability;

h) sensitivity characteristics of the environmental receptors to the product;

i) cost to remediate potential contamination;

j) cost to clean tank and repair;

k) cost associated with loss of use;

l) impact on public safety and health;

m) dike containment capabilities (volume and leak tightness).

6.4.3 Internal Inspection Deferral

The internal inspection deferral may be applied to the internal inspection due date of tanks on a calendar-based inspection schedule. The owner/operator should review regulatory requirements and consult with the authority having jurisdiction. The internal inspection deferral may be based on the standard deferral of 6.4.3.1 or other approaches, such as the risk-based deferral of 6.4.3.2.

6.4.3.1 Standard Deferral

The deferral may be approved by the owner/operator if all of the following conditions are met.

a) The current internal inspection due date has not been previously deferred.

b) The deferred internal inspection due date shall not increase the current internal inspection interval by more than 10 % or 12 months, whichever is less.

c) Previous internal inspection and repairs were performed in accordance with API 653, or for an initial service interval, the tank was constructed to API 650.

d) A review of the current operating conditions, previous internal API 653 inspection if available, external API 653 inspections, and routine monthly inspections have been completed with results that support a deferral. The owner/operator shall determine if modifications are needed to support the deferral.

e) The deferral request has the written agreement of an authorized inspector and tank owner/operator.

f) Other regulatory floating roof seal inspection intervals have been met.

g) Cathodic protection systems, if present, are operating in accordance with API RP 651.

h) An API 653 external inspection according to 6.3.2 has been completed within 12 months before the current internal inspection due date.

i) The owner/operator has stated a valid reason for the deferral and documented in writing an assessment of alternative measures that have been considered.

j) Updates to the tank records with deferral documentation are complete before it is operated beyond the current internal inspection due date.

6.4.3.2 Risk-based Deferral

The deferral may be approved using a risk-based inspection (RBI) procedure following the guidance in API 653 6.4.2.1.2 and 6.4.2.2.2. An RBI deferral requires that the owner/operator revisit the RBI assessment to determine if the risk is acceptable for the deferral extension time being evaluated.

6.5 Alternative to Internal Inspection to Determine Bottom Thickness

In cases where construction, size, or other aspects allow external access to the tank bottom to determine bottom thickness, an external inspection in lieu of an internal inspection is allowed to meet the data requirements of Table 4.4. However, in these cases, consideration of other maintenance items may dictate internal inspection intervals. This alternative approach shall be documented and made part of the permanent record of the tank.

6.6 Preparatory Work for Internal Inspection

Specific work procedures shall be prepared and followed when conducting inspections that will assure personnel safety and health and prevent property damage in the workplace (see 1.4).

6.7 Inspection Checklists

Annex C provides sample checklists of items for consideration when conducting in-service and out-of-service inspections.

6.8 Records

6.8.1 General

Inspection records form the basis of a scheduled inspection/maintenance program. (It is recognized that records may not exist for older tanks, and judgments must be based on experience with tanks in similar services.) The owner-operator shall maintain a complete record file consisting of three types of records, namely: construction records, inspection history, and repair/alteration history.

6.8.2 Construction Records

Construction records may include nameplate information, drawings, specifications, construction completion report, and any results of material tests and analyses.

6.8.3 Inspection History

The inspection history includes all measurements taken, the condition of all parts inspected, and a record of all examinations and tests. A complete description of any unusual conditions with recommendations for correction of details which caused the conditions shall also be included. This file will also contain corrosion rate and inspection interval calculations.

6.8.4 Repair/Alteration History

The repair/alteration history includes all data accumulated on a tank from the time of its construction with regard to repairs, alterations, replacements, and service changes (recorded with service conditions such as stored product temperature and pressure). These records should include the results of any experiences with coatings and linings.

6.9 Reports

6.9.1 General

For each external inspection performed per 6.3.2 and each internal inspection performed per 6.4, the authorized inspector shall prepare a written report. These inspection reports along with inspector recommendations and documentation of disposition shall be maintained by the owner/operator for the life of the tank. Local jurisdictions may have additional reporting and record keeping requirements for tank inspections.

6.9.2 Report Contents

Reports shall include at a minimum the following information:

a) date(s) of current inspection;

b) if required by the owner and the previous inspection reports are provided prior to the inspection, the new inspection report shall include:

   1) the dates of previous internal inspection;

   2) areas of concern from previous inspection; and

   3) condition of previously repaired areas;

c) date of installation or repair of components that are subject to corrosion rate calculations, if available;

d) type of inspection (external or internal);

e) scope of inspection, including any areas that were not inspected, with reasons given (e.g. limited scope of inspection, limited physical access;

f) description of the tank (number, size, capacity, year constructed, materials of construction, service history, roof and bottom design, age of bottom, etc.), if available;

g) list of components inspected and conditions found (a general checklist such as found in Annex C may be used to identify the scope of the inspection) and deficiencies found;

h) inspection methods and tests used (visual, MFL, UT, etc.) and results of each inspection method or test;

i) minimum measured remaining thickness of corroded bottom plate to be detected, recorded, and repaired;

j) corrosion rates of the bottom (report both the corrosion rates calculated from data measured before repairs and the calculated future corrosion rates after repairs and mitigation), shell, roof plate, and accessible roof structural;

k) requirements for repair and mitigation of corrosion necessary to support calculation for the next internal inspection;

l) the measured, uncorroded thickness of at least one shell plate in each shell course and of each bottom plate;

m) for bottom corrosion, record the location, measured range of remaining plate thickness, and type of corrosion (product side or soil side) of all corrosion pits and corrosion areas to be repaired. If no corrosion pits or areas require repair, then record the maximum product side pit depth and the minimum thickness from soil side corrosion that was measured;

n) number and location of any corrosion through-holes on the tank bottom or shell;

o) settlement survey measurements and analysis (if performed);

p) recommendations per 6.9.3.1;

q) name, company, API 653 certification number and signature of the authorized inspector responsible for the inspection;

r) drawings, photographs, NDE reports and other pertinent information shall be appended to the report.

6.9.3 Recommendations

6.9.3.1 Reports shall include recommendations for repairs and monitoring necessary to restore the integrity of the tank per this standard and/or maintain integrity until the next inspection, together with reasons for the recommendations. The recommended maximum inspection interval and basis for calculation of that interval shall also be stated. Additionally, reports may include other less critical observations, suggestions and recommendations.

6.9.3.2 It is the responsibility of the owner/operator to review the inspection findings and recommendations, establish a repair scope, if needed, and determine the appropriate timing for repairs, monitoring, and/or maintenance activities. Typical timing considerations and examples of repairs are:

a) *prior to returning the tank to service*—repairs critical to the integrity of the tank (e.g. bottom or shell repairs);

b) *after the tank is returned to service*—minor repairs and maintenance activity (e.g. drainage improvement, painting, gauge repairs, grouting, etc.);

c) *at the next scheduled internal inspection*—predicted or anticipated repairs and maintenance (e.g. coating renewal, planned bottom repairs, etc.);

d) *monitor condition for continued deterioration*—(e.g. roof and/or shell plate corrosion, settlement, etc.).

The owner/operator shall ensure that the disposition of all recommended repairs and monitoring is documented in writing and that reasons are given if recommended actions are delayed or deemed unnecessary.

6.10 Nondestructive Examination (NDE)

Personnel performing NDE shall meet the qualifications identified in 12.1.1.2, but need not be certified in accordance with Annex D. The results of any NDE work, however, must be considered in the evaluation of the tank by an authorized inspector.

SECTION 7—MATERIALS

7.1 General

This section provides general requirements for the selection of materials for the repair, alteration, and reconstruction of existing tanks. Specific requirements for repairs and alterations are covered in Section 9.

7.2 New Materials

All new materials used for repair, alterations, or reconstruction shall conform to the current applicable standard.

7.3 Original Materials for Reconstructed Tanks

7.3.1 Shell and Bottom Plates Welded to the Shell

7.3.1.1 All shell plate materials and bottom plates welded to the shell shall be identified. Materials identified by original contract drawings, API nameplates, or other suitable documentation do not require further identification. Material not identified shall be tested and identified by the requirements as outlined in 7.3.1.2. After identification, determination shall be made as to suitability of the material for intended service.

7.3.1.2 Each individual plate for which adequate identification does not exist shall be subjected to chemical analysis and mechanical tests as required in ASTM A6 and ASTM A370 including Charpy V-notch. Impact values shall satisfy the requirements of API 650 Section 4.2.9, API 650 Section 4.2.10, API 650 Section 4.2.11, and API 650 Table 4.4a or API 650 Table 4.4b. When the direction of rolling is not definitely known, two tension specimens shall be taken at right angles to each other from a corner of each plate, and one of those test specimens must meet the specification requirements.

7.3.1.3 For known materials, all shell plates and bottom plates welded to the shell shall meet, as a minimum, the chemistry and mechanical properties of material specified for the application with regard to thickness and design metal temperature given in API 650, Figure 4.1a or Figure 4.1b.

7.3.2 Structural

Existing rolled structural shapes that are to be reused shall meet the requirement of ASTM A7 as a minimum. New structural material shall meet the requirements of ASTM A36 or ASTM A992 as a minimum.

NOTE ASTM A7 was a steel specification that was discontinued in the Fourth Edition of API 650, 1970.

7.3.3 Flanges and Fasteners

7.3.3.1 Flange material shall meet the minimum requirements of the material specifications in the as-built standard.

7.3.3.2 Fasteners shall meet the material specifications of the current applicable standard.

7.3.4 Roof, Bottom, and Plate Windgirders

If existing plates are to be used to reconstruct the tank, they shall be checked for excessive corrosion and pitting (see Section 4 and Section 6).

7.4 Welding Consumables

Welding consumables shall conform to the AWS classification that is applicable to the intended use.

SECTION 8—DESIGN CONSIDERATIONS FOR RECONSTRUCTED TANKS

8.1 General

Any specific design considerations other than normal product loading shall be specified by the owner/operator. See 4.4.3 for release prevention systems and release prevention barrier definition.

8.2 New Weld Joints

8.2.1 Weld joint details shall meet the welding requirements of the current applicable standard.

8.2.2 All new shell joints shall be butt-welded joints with complete penetration and complete fusion.

8.3 Existing Weld Joints

Existing weld joints shall meet the requirements of the as-built standard.

8.4 Shell Design

8.4.1 Thickness to be used for each shell course when checking tank design shall be based on measurements taken within 180 days prior to relocation. (See 4.3.2 for measuring procedure, number, and locations of measured thicknesses.)

8.4.2 The maximum design liquid level for product shall be determined by calculating the maximum design liquid level for each shell course based on the specific gravity of the product, the actual thickness measured for each shell course, the allowable stress for the material in each course, and the design method to be used. The allowable stress for the material shall be determined using API 650, Table 5.2a or Table 5.2b. For material not listed in Table 5.2a or Table 5.2b, an allowable stress value of the lesser of $^{2}/_{3}$ yield strength or $^{2}/_{5}$ tensile strength shall be used.

8.4.3 The maximum liquid level for hydrostatic test shall be determined by using the actual thickness measured for each shell course, the allowable stress for the material in each course, and the design method to be used. The allowable stress for the material shall be determined using API 650, Table 5.2a or Table 5.2b. For material not listed in Table 5.2a or Table 5.2b, an allowable stress value of the lesser of $^{3}/_{4}$ yield strength or $^{3}/_{7}$ tensile strength shall be used.

8.4.4 If a corrosion allowance is required for the reconstructed tank, the required corrosion allowance shall be deducted from the actual thickness before calculating the maximum liquid level. If the actual thickness is greater than that necessary to allow the liquid level required, the extra thickness can be considered as corrosion allowance.

8.4.5 The joint efficiency and allowable stress levels used for the design liquid level calculations shall be consistent with the design method used and with the degree and type of examination made on welded joints. The joint efficiency and allowable stress levels for existing welded joints that are not to be removed and replaced shall be based on the original degree and type of examination.

8.5 Shell Penetrations

8.5.1 Replacement and new penetrations shall be designed, detailed, welded, and examined to meet the requirements of the current applicable standard.

8.5.2 Existing penetrations shall be evaluated for compliance with the as-built standard.

8.6 Windgirders and Shell Stability

8.6.1 Top and intermediate windgirders for open top tanks shall meet the requirements of the current applicable standard.

8.6.2 Tanks to be reconstructed shall be checked for wind-induced buckling in accordance with the procedures of the current applicable standard, using the wind requirements for the location where the tank will be reconstructed.

8.7 Roofs

8.7.1 Roof designs shall meet the requirements of the as-built standard.

8.7.2 If the new site requires a larger design load than the original site, the adequacy of the existing roof shall be evaluated using the current applicable standard.

8.8 Seismic Design

Tanks that will be reconstructed shall be checked for seismic stability based on the rules of the current applicable standard using the dimensions and thicknesses of the reconstructed tank. Reconstructed tanks shall be built to meet the stability requirements of the current applicable standard. Thickened bottom plates under the bottom shell course or anchoring of the tank may be required even if not used on the original tank.

SECTION 9—TANK REPAIR AND ALTERATION

9.1 General

9.1.1 The basis for repairs and alterations shall be an API 650 equivalence.

9.1.2 Hydrostatic testing requirements, NDE requirements, acceptance criteria for the welds, and repairs to shell plate and existing welds are specified in Section 12.

9.1.3 All alternation and repair work shall be approved before commencement of the work. The specific section of this standard governing each alteration/repair shall be consulted for details or required approval.

9.1.4 If approval details are not given in a specific section:

a) a storage tank engineer experienced in storage tank design shall approve:

1) all alterations to storage tanks that comply with API 650;

2) any repair requiring hydrostatic testing;

3) any repair that requires an engineering evaluation;

b) an authorized inspector or storage tank engineer shall approval limited, minor, or routine repairs that are not addressed in item a) above.

9.1.5 If requested by the tank operator/owner, an authorized inspector or a storage tank engineer shall designate:

a) inspection hold points required during the alteration or repair sequence;

b) minimum documentation to be submitted.

9.1.6 All approved design, work execution, materials, welding procedures, examination, and testing methods shall be verified by the authorized inspector or storage tank engineer. The authorized inspector or storage tank engineer shall verify all specific alteration/repair work at the designated hold points and after alterations/repairs have been completed in accordance with the requirements of this standard.

9.1.7 All required documentation related to the alteration/repair of the tank shall be submitted upon job completion or as specified by the tank owner/operator.

9.1.8 Annex F summarizes the requirements by method of examination and provides the acceptance standards, examiner qualifications, and procedure requirements. Annex F is not intended to be used alone to determine the examination requirements for work covered by this document. The specific requirements as listed in Section 1 through Section 12 shall be followed in all cases.

9.2 Removal and Replacement of Shell Plate Material

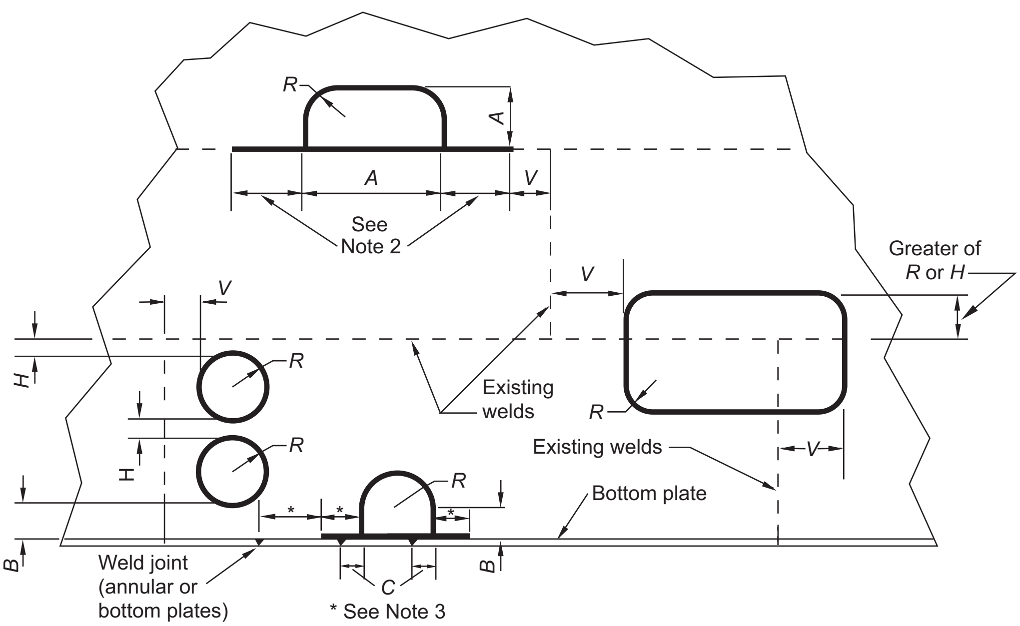
9.2.1 Minimum Thickness of Replacement Shell Plate

The minimum thickness of the replacement shell plate material shall be calculated in accordance with the as-built standard. The thickness of the replacement shell plate shall not be less than the greatest nominal thickness of any plate in the same course adjoining the replacement plate except where the adjoining plate is a thickened insert plate. Any changes from the original design conditions, such as specific gravity, design pressure, liquid level, and shell height, shall be considered.

9.2.2 Minimum Dimensions of Replacement Shell Plate

9.2.2.1 The minimum dimension for a replacement shell plate is 300 mm (12 in.) or 12 times the thickness of the replacement plate, whichever is greater. The replacement plate may be circular, oblong, square with rounded corners, or rectangular with rounded corners except when an entire shell plate is replaced. See Figure 9.1 for typical details of acceptable replacement shell plates.

9.2.2.2 Where one or more entire shell plates or full height segments of shell plates are to be removed and replaced, the minimum spacing requirements specified in Figure 9.1 for vertical weld joints shall be maintained. It is acceptable to remove and replace entire shell plates or full height segments of shell plates by cutting and rewelding along the existing horizontal weld joints. Prior to welding the new vertical joints, the existing horizontal welds shall be cut for a minimum distance of 300 mm (12 in.) beyond the new vertical joints. The vertical joints shall be welded prior to welding the horizontal joints.



Dimension	Minimum Weld Spacing Between Edges (Toes) of Welds for Thickness of Replacement Shell Plate, *t*, millimeters	
	$t \leq 13$ mm	$t > 13$ mm
R	150 mm	Greater of 150 mm or 6*t*
B	150 mm	Greater of 250 mm or 8*t*
H	75 mm	Greater of 250 mm or 8*t*
V	150 mm	Greater of 250 mm or 8*t*
A	300 mm	Greater of 300 mm or 12*t*
C	Greater of 75 mm or 5*t*	

Dimension	Minimum Weld Spacing Between Edges (Toes) of Welds for Thickness of Replacement Shell Plate, *t*, (inches)	
	$t \leq 0.5$ in.	$t > 0.5$ in.
R	6 in.	Greater of 6 in. or 6*t*
B	6 in.	Greater of 10 in. or 8*t*
H	3 in.	Greater of 10 in. or 8*t*
V	6 in.	Greater of 10 in. or 8*t*
A	12 in.	Greater of 12 in. or 12*t*
C	Greater of 3 in. or 5*t*	

NOTE 1 All weld intersections shall be at approximately 90º.

NOTE 2 Prior to welding new vertical joints, cut existing horizontal weld for a minimum of 300 mm (12 in.) beyond the new vertical joints. Weld the horizontal joint last.

NOTE 3 Prior to welding new vertical joints, cut existing shell-to-bottom weld for a minimum of 300 mm (12 in.) beyond the new vertical joints. The cut shall extend past or stop short of existing bottom plate welds by at least 75 mm (3 in.) or 5*t*. Weld the shell-to-bottom weld last.

Figure 9.1—Acceptable Details for Replacement of Shell Plate Material

9.2.3 Weld Joint Design

9.2.3.1 Shell replacement plates shall be welded with butt joints with complete penetration and complete fusion, except as permitted for lapped patch shell repairs.

9.2.3.2 Weld joint design for replacement shell plates shall be in accordance with API 650, Section 5.1.5.1 through Section 5.1.5.3. Joints in lap-welded shell tanks may be repaired according to the as-built standard. Lap-welded joint design for lapped patch shell repairs shall meet the requirements of 9.3. Details of welding shall be in accordance with 7.2 of API 650, and Section 9 of this standard.

9.2.3.3 For existing shell plates over 13 mm ($^1/_2$ in.) thick, the outer edge of the butt weld attaching the replacement shell plate shall be at least the greater of 8 times the weld thickness or 250 mm (10 in.) from the outer edge of any existing butt-welded shell joints. For existing shell plates 13 mm ($^1/_2$ in.) thick and less, the spacing may be reduced to 150 mm (6 in.) from the outer edge of vertical joints or 75 mm (3 in.) from the outer edge of horizontal joints. See Figure 9.1 for minimum dimensions.

For existing shell plates over 13 mm ($^1/_2$ in.) thick, the outer edge of the butt weld attaching the replacement shell plate shall be at least the greater of 8 times the weld size or 250 mm (10 in.) from the edge (toe) of the fillet weld attaching the bottom shell course to the bottom except when the replacement shell plate extends to and intersects the bottom-to-shell joint at approximately 90°. For existing shell plates 13 mm ($^1/_2$ in.) thick and less, this spacing may be reduced to 150 mm (6 in.) For shell plates of unknown toughness not meeting the exemption criteria of Figure 5.2, the edge of any vertical weld joint attaching a replacement plate shall be at 75 mm (3 in.) or 5t from the edge of a weld joint in the bottom annular ring or weld joints in bottom plates under the tank shell. Figure 9.1 has minimum dimensions.

9.2.3.4 To reduce the potential for distortion of an existing tank due to welding a replacement plate into an existing tank shell, fit-up, heat input, and welding sequence must be considered.

9.2.4 Door Sheet Installation

This section describes the requirements for reinstallation or replacement of a door sheet. The requirements of Figure 9.1, Figure 9.2, Figure 9.3, Figure 9.4, and Figure 9.5 shall be used to locate door sheets relative to existing seams, unless an alternative design is designed by a storage tank engineer and the owner/operator approves the alternative in writing.

9.2.4.1 Door sheet installation shall meet the requirements of 9.2.1, 9.2.2, 9.2.3, and 12.2.1.6.

9.2.4.2 The removed shell plate section of a door sheet in a butt-welded tank may be reinstalled in its original location or the section may be replaced with new shell plate material. In either case the door sheet installation shall utilize joints with complete penetration and complete fusion.

9.2.4.3 Large door sheets of the type shown in Figures 9.2, 9.3, 9.4, and 9.5 should have the top and/or sides of the opening stiffened to prevent a) sagging and deformation of the shell at the top of the opening, and b) shell deformations at the sides and upper corners resulting when the door sheet is first removed or when it is replaced and welded into the shell. Installation of the stiffening members should be done prior to cutting the door sheet, providing it is safe to do so, and the members should remain in place until the door sheet is completely and satisfactorily reinstalled. The specific arrangement and details of the stiffening should be determined by a storage tank engineer. Door sheet stiffening, when used, usually consists of one or a combination of angle, channel, or wide flange section members.

9.2.4.4 For lap-welded and riveted tanks, reinstallation of an original plate section that crosses an existing horizontal seam is not permitted.

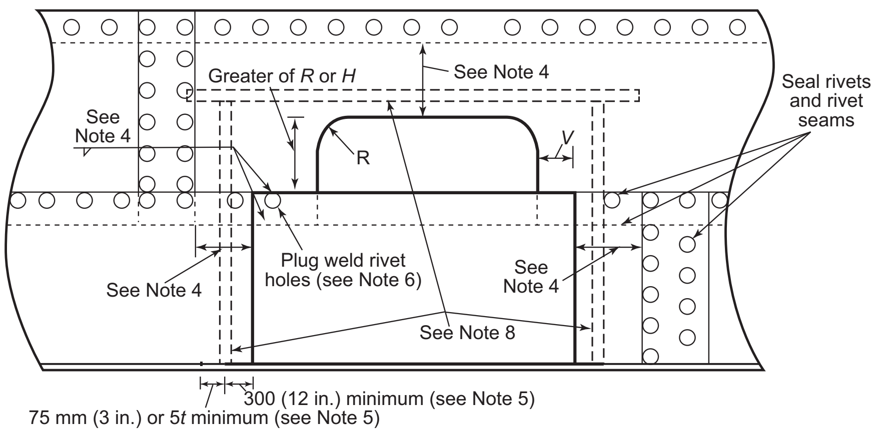
9.2.4.5 Door sheets that cross vertical riveted or lap-welded seams are not permitted in any case.

9.2.4.6 If a door sheet vertical cut-line crosses an existing seam in a butt-welded tank without an offset and the removed section is reinstalled, then additional weld examination shall be required at the intersection of the new vertical weld seam and existing horizontal weld seam. In addition to the examination requirements of 12.1.5.1, the back gouged surface of the root pass and the final pass (each side) of the new welds shall be examined by magnetic particle or liquid penetrant methods. The existing horizontal weld seam intersected by the new vertical weld shall also be examined by magnetic particle or liquid penetrant methods for a 150 mm (6 in.) distance on both sides.

NOTE "Offset" is the horizontal distance between the vertical welds above and below a horizontal seam, as shown in Figure 9.2, Figure 9.3, and Figure 9.5.

9.2.4.7 If a door sheet vertical cut-line crosses an existing seam in a butt-welded tank with an offset, the minimum offset must equal dimension 'V' as shown in Figure 9.5. Prior to welding the new vertical seams, cut existing horizontal seam weld for a minimum of 300 mm (12 in.) beyond the new vertical joints. Weld the horizontal seam last.

9.2.4.8 If a door sheet cut line crosses a lap-welded or a riveted horizontal seam, the replacement assembly shall be constructed of two separate plates, with the lower section butt-welded to the adjacent shell course by means of full penetration, full fusion vertical welds. The upper section shall be lapped over or under the lower section and the upper plate shall be butt-welded to the existing shell plate. After the butt welds are completed, the horizontal lap shall be fillet welded along both inside and outside edges.



NOTES:
1. See table in Figure 9.1 for minimum weld spacing and dimensions *H, R,* and *V*.
2. When a door sheet crosses the horizontal joint between two courses, a replacement door sheet assembly shall be constructed of two separate plates. The upper door sheet thickness shall be the same as the higher shell course thickness. The lower door sheet thickness shall be the same as the lower shell course thickness.
3. Fillet Weld size shall be equal to thickness of thinner of two plates.
4. Rivets and existing lap rivet seams located within 300 mm (12 in.) of a weld may need to be sealed with caulk/coating or seal welded to prevent product seepage.
5. Prior to welding new vertical seam which intersect the bottom plate, cut existing shell-to-bottom weld for a minimum of 300 mm (12 in.) beyond the new vertical weld seam. The cut shall extend past or stop short of existing bottom plate welds by at least 75 mm (3 in.) or 5*t*. Weld the shell-to-bottom weld last.
6. Plug weld all rivet holes in the shell plate where rivets are removed. Filler weld to full plate thickness and grind flush.
7. Door sheets need not extend to shell-to-bottom weld provided that weld spacing and corner radii are in accordance with Figure 9.1.
8. See 9.2.4.3. Stiffener arrangement may vary from that shown.

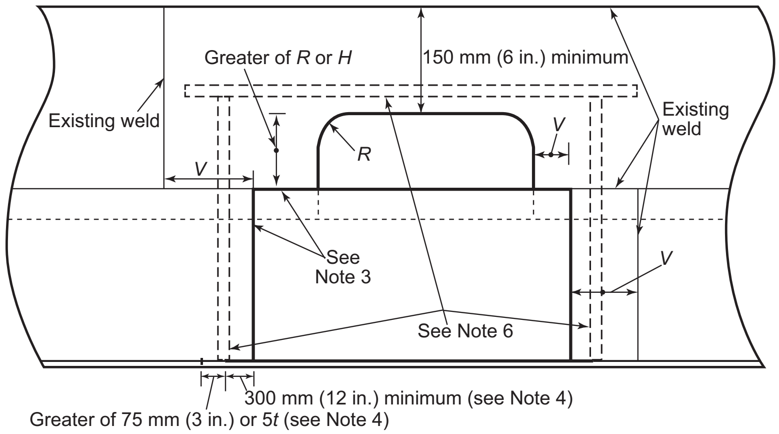
Figure 9.2—Details for Door Sheets in Riveted Seam Tank

9.2.4.9 New weld seams in riveted tanks shall be located a minimum of 300 mm (12 in.) from existing rivet seams to minimize potential for rivet and rivet seam leaks or the rivets and existing lap rivet seams shall be seal welded or sealed by the application of caulk or coating that is compatible with the specified stored product.

NOTE The heat created by welding may cause nearby rivets and rivet seams to leak.

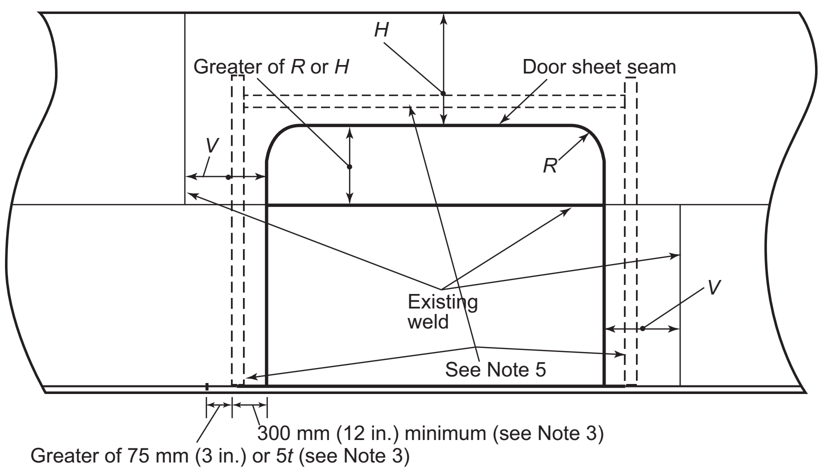
9.3 Shell Repairs Using Lap-welded Patch Plates

9.3.1 Lapped patch shell repairs are an acceptable form of repair for butt-welded, lap-welded, and riveted tank shells, under the conditions outlined in 9.3.2, 9.3.3, and 9.3.4; only when specified by the owner/operator. In addition, the repair details shall comply with the requirements of 9.3.1.1 through 9.3.1.10. These repairs are permanent repairs subject to an ongoing inspection and maintenance program. These requirements may be used to evaluate existing lapped patch shell repairs; however, the plate thickness limits need not apply.



NOTES:
1. See table in Figure 9.1 for minimum weld spacing and dimensions *H*, *R*, and *V*.
2. When a door sheet crosses the horizontal joint between two courses, a replacement door sheet assembly shall be comprised of two separate plates. The upper door sheet thickness shall be the same as the higher shell course thickness. The lower door sheet thickness shall be the same as the lower shell course thickness.
3. Fillet Weld size shall be equal to thickness of thinner of two plates.
4. Prior to welding new vertical joints which intersect the bottom plate, cut existing shell-to-bottom weld for a minimum of 300 mm (12 in.) beyond the new vertical weld joint. The cut shall extend past or stop short of existing bottom plate welds by at least 75 mm (3 in.) or 5*t*. Weld the shell-to-bottom weld last.
5. Door sheets need not extend to shell-to-bottom weld provided that weld spacing and corner radii are in accordance with Figure 9.1.
6. See 9.2.4.3. Stiffener arrangement may vary from that shown.

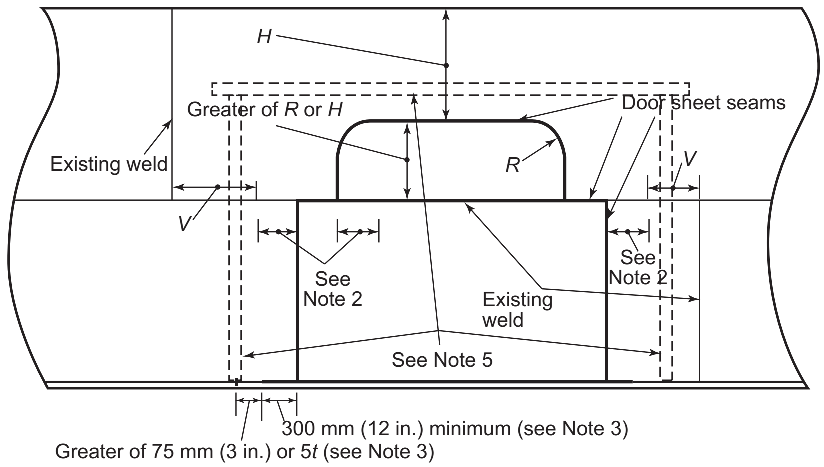
Figure 9.3—Details for Door Sheets in Lap-welded Seam Tank



NOTES:
1. See table in Figure 9.1 for minimum weld spacing and dimensions *H*, *R*, and V.
2. Detail shown for door sheet that utilizes removed section of tank shell. If new material is utilized, see Figure 9.1 for requirements.
3. Prior to welding new vertical weld seam which intersects the bottom plate, cut existing shell-to-bottom weld for a minimum of 300 mm (12 in.) beyond the new vertical weld seam. The cut shall extend past or stop short of existing bottom plate welds by at least 75 mm (3 in.) or 5*t*. Weld the shell-to-bottom weld last.
4. Door sheets need not extend to shell-to-bottom weld provided that weld spacing and corner radii are in accordance with Figure 9.1.
5. See 9.2.4.3. Stiffener arrangement may vary from that shown.

Figure 9.4—Details for Door Sheets in Butt-welded Shell Seam Tank—No Vertical Seam Offset

9.3.1.1 All repair material shall comply with the requirements of the current applicable standard of construction and API 653.



NOTES:
1. See table in Figure 9.1 for minimum weld spacing and dimensions *H*, *R*, and *V*.
2. Prior to welding new vertical joints, cut the existing horizontal weld for a minimum of 300 mm (12 in.) beyond the new vertical weld seam. Weld the horizontal seam last.
3. Prior to welding new vertical joints which intersect the bottom plate, cut the existing shell-to-bottom weld for a minimum of 300 mm (12 in.) beyond the new vertical weld joint. The cut shall extend past or stop short of existing bottom plate welds by at least 75 mm (3 in.) or 5*t*. Weld the shell-to-bottom weld last.
4. Door sheets need not extend to shell-to-bottom weld provided that weld spacing and corner radii are in accordance with Figure 9.1.
5. See 9.2.4.3. Stiffener arrangement may vary from that shown.

Figure 9.5—Details for Door Sheets in Butt-welded Shell Seam Tank—Vertical Seam Offset

9.3.1.2 Lapped patch shell repairs shall not be used on any shell course thickness (original construction) that exceeds 13 mm (1/2 in.), nor to replace door sheets or shell plates.

9.3.1.3 Except as permitted in 9.3.3.2 and 9.3.4.3, the repair plate material shall be the smaller of 13 mm (1/2 in.) or the thickness of the shell plate adjacent to the repairs, but not less than 5 mm (3/16 in.).

9.3.1.4 The shape of the repair plate may be circular, oblong, square, or rectangular. All corners, except at the shell-to-bottom joint, shall be rounded to a minimum radius of 50 mm (2 in.) The nozzle reinforcing plate shapes of API 650, Figure 5.8, are also acceptable.

9.3.1.5 The repair plate may cross any butt-welded vertical or horizontal shell seams that have been ground flush, but must overlap a minimum of 150 mm (6 in.) beyond the shell seam. The weld spacing requirements of Figure 9.1 shall be used as a basis for locating repair plates relative to butt-welded, fillet-welded, and riveted seams and other repair plates.

9.3.1.6 Repair plates may extend to and intersect with the external shell-to-bottom joint if the vertical sides intersect the tank bottom at a 90° angle and the shell-to-bottom weld is in conformance with Figure 9.6. Repair plates positioned on the shell interior shall be located such that the toe-to-toe weld clearances are a minimum of 150 mm (6 in.) to the shell-to-bottom weld.

9.3.1.7 The maximum vertical and horizontal dimension of the repair plate is 1.2 m (48 in.) and 1.8 m (72 in.), respectively. The minimum repair plate dimension is 100 mm (4 in.) The repair plate shall be formed to the shell radius.

9.3.1.8 Shell openings and their reinforcements shall not be positioned within a lapped patch shell repair.

9.3.1.9 Prior to application of a lapped patch shell repair, the areas to be welded shall be ultrasonically examined for plate defects and remaining thickness.

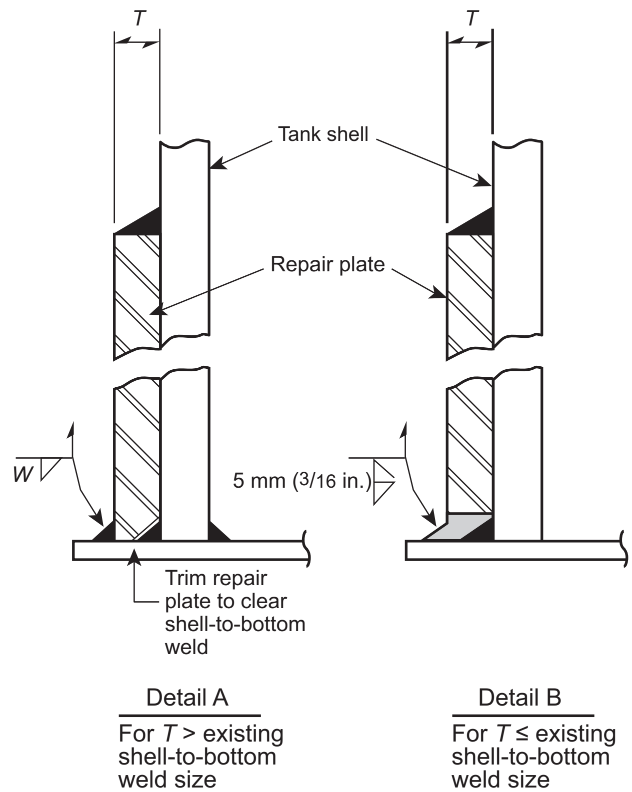


Figure 9.6—Lapped Patch Repair Plates at the External Shell-to-bottom Joint

9.3.1.10 Repair plates shall not be lapped onto lap-welded shell seams, riveted shell seams, other lapped patch repair plates, distorted areas, or unrepaired cracks or defects.

9.3.2 Lapped patch repair plates may be used for the closure of holes caused by the removal of existing shell openings or the removal of severely corroded or eroded areas. In addition, the following requirements shall be satisfied.

9.3.2.1 The welding shall be continuous on the outer perimeter of the repair plate and the inner perimeter of the hole in the shell plate. The minimum hole diameter is 50 mm (2 in.). Shell openings due to plate removal shall have a minimum corner radius of 50 mm (2 in.).

9.3.2.2 Nozzle necks and reinforcing plates shall be entirely removed prior to installation of a repair plate.

9.3.2.3 The repair plate thickness selection shall be based on a design that conforms to the as-built standard and API 653, using a joint efficiency not exceeding 0.70. The welds of the repair plate shall be full fillet welds. The minimum repair plate dimension shall be 100 mm (4 in.) with a minimum overlap of 25 mm (1 in.) and a maximum overlap of 8 times the shell thickness (8*t*).

9.3.2.4 The repair plate thickness shall not exceed the nominal thickness of the shell plate adjacent to the repair.

9.3.3 Lapped patch repair plates may be used to reinforce areas of severely deteriorated shell plates that are not able to resist the service loads to which the tank is to be subjected. Lapped patch repair plates may also be used for shell plates that are below the retirement thickness, providing the following additional requirements are satisfied.

9.3.3.1 The selection of the repair plate thickness shall be based on a design that conforms to the as-built standard and API 653, using a joint efficiency not exceeding 0.35. The perimeter weld shall be a full fillet weld.

9.3.3.2 The repair plate thickness shall not exceed the shell plate thickness at the perimeter of the repair plate by more than one-third, but no more than 3 mm ($^1/_8$ in.). The repair plate thickness shall not exceed 13 mm ($^1/_2$ in.).

9.3.3.3 The remaining strength of the deteriorated areas under the repair plate shall not be considered as effective in carrying the calculated service or hydrotest loads.

9.3.4 Lapped patch repair plates may be used to repair small shell leaks, or minimize the potential from leaks from severely isolated or widely scattered pitting if the following requirements are satisfied.

9.3.4.1 The existing shell thickness, excluding the holes and pitting, meets the minimum acceptable shell thickness as determined by 4.3.2 and 4.3.3.

9.3.4.2 The repair plate is designed to withstand the hydrostatic pressure load between the repair plate and the shell assuming a hole exists in the shell using a joint efficiency of 0.35.

9.3.4.3 The repair plate thickness shall not exceed the shell plate thickness at the perimeter of the repair plate by more than one-third, but no more than 3 mm ($^1/_8$ in.). The repair plate thickness shall be no thinner than 5 mm ($^3/_{16}$ in.) nor thicker than 13 mm ($^1/_2$ in.). A full fillet perimeter weld is required.

9.3.4.4 This repair method shall not be used if exposure of the fillet welds to the product will produce crevice corrosion or if a corrosion cell between the shell plate and repair plate is likely to occur.

9.3.4.5 This repair method shall not be used to repair shell leaks if the presence of product between the shell plate and repair plate will prevent gas freeing from the tank to perform hot work.

9.3.4.6 The existing shell plate under the repair plate shall be evaluated at each future inspection to ensure it satisfies the requirements of 9.3.4.1. If the existing shell plate thickness does not satisfy 9.3.4.1 or the repair plate does not satisfy 9.3.3, the area is to be repaired in accordance with 9.2 or 9.3.2.

9.4 Repairs Using Nonmetallic Materials

This section of API 653 together with Annex J provides the specific options, deletions, additions, or modifications to the requirements and design options for nonmetallic repairs. It identifies the required inputs and decisions by the Purchaser. It also provides recommendations, requirements, and information that supplements ASME PCC-2 Article 4.1. This section and Annex J become requirements only when the Purchaser specifies an option covered by that Annex (not at the Contractor's discretion). The Owner/Operator shall also utilize an experienced storage tank engineer to identify the life span (temporary or fixed time limitation) requirements for the repair system.

Nonmetallic repairs can be made on shell plate or nozzle neck to restore hoop strength capacity lost due to corrosion. The Owner/Operator, storage tank engineer, and composite manufacturer shall evaluate the ability of the nonmetallic repair to restore the hoop strength and consider the possibility of non-tensile related forces damaging the composite repair in the selection of the repair method and in the risk assessment. The tank shall be assessed to confirm it is sufficient to handle tensile, external, axial, dead and seismic loads.

9.5 Repair of Defects in Shell Plate Material

The need for repairing indications such as cracks, gouges or tears (such as those often remaining after the removal of temporary attachments), widely scattered pits, and corroded areas discovered during an inspection of the tank shell shall be determined on an individual case basis in accordance with Section 4. In areas where the shell plate thickness exceeds that required by design conditions, it is permissible to grind surface irregularities to a smooth contour so long as the remaining thickness is adequate for the design conditions. Where grinding to a smoothly contoured surface will result in unacceptable shell plate metal thickness, the shell plate may be repaired by deposition of weld metal, followed by examination and testing in accordance with 12.1.8. If more extensive areas of shell plate require repair, use of butt-welded shell replacement plate or lap-welded patch plate shall be considered.

9.6 Alteration of Tank Shells to Change Shell Height

Tank shells may be altered by adding new plate material to increase the height of the tank shell. The modified shell height shall be in accordance with the requirements of the current applicable standard and shall take into consideration all anticipated loadings such as wind and seismic.

9.7 Repair of Defective Welds

Repairs of shell weld flaws and defects are described in the following subsections.

9.7.1 Cracks, lack of fusion, and rejectable slag and porosity that need repair shall be removed completely by gouging and/or grinding and the resulting cavity properly prepared for welding and then welded.

9.7.2 Excessive reinforcement shall be repaired by grinding if required by 4.3.8.2.

9.7.3 Existing weld undercut deemed unacceptable shall be repaired by additional weld metal, or grinding, as appropriate.

9.7.4 Welded joints that have experienced unacceptable loss of metal due to corrosion shall be repaired by grinding and/or welding.

9.7.5 Unacceptable surface defects shall be repaired by grinding and/or welding.

9.7.6 After repairs of weld defects listed 9.7 are completed, the repaired areas shall be examined in accordance with the requirements of 12.1.3, except that repairs for undercut, corrosion, and surface defects in butt welds do not require radiographic or ultrasonic examination.

9.8 Repair of Shell Penetrations

9.8.1 Repairs to existing shell penetrations shall be in compliance with API 650, Section 5.7.

9.8.2 Reinforcing plates may be added to existing unreinforced nozzles when deemed appropriate. The reinforcing plate shall meet all dimensional and weld spacing requirements of API 650, Section 5.7. See Figure 9.7 and Figure 9.8 for acceptable details.

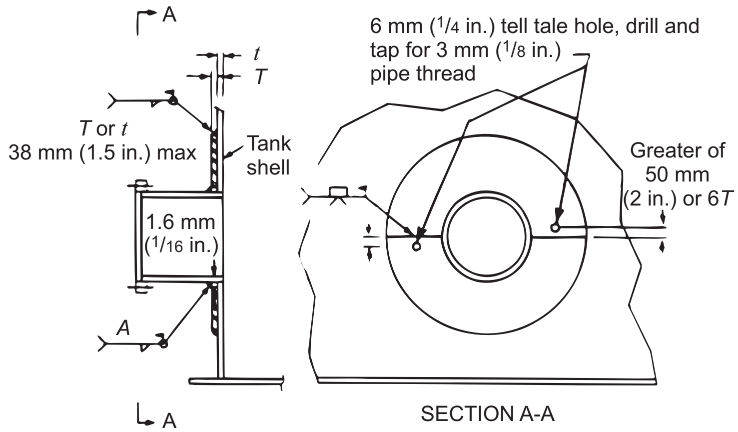
9.8.3 As an alternative, the reinforcing plates may be added to the inside of the tank provided that sufficient nozzle projection exists.

9.9 Addition or Replacement of Shell Penetrations

9.9.1 New shell penetrations (addition or replacement) shall be in accordance with material, design, and stress relief requirements of API 650, Section 5.7 and in accordance with 9.9.2 through 9.9.6 of this standard.

9.9.2 The required penetration reinforcement area of API 650, Section 5.7.2, shall be determined using the required shell thickness calculated by the equation in 4.3.3.1 b) of this standard except the variable S shall be the allowable design stress from API 650, Table 5.2a or Table 5.2b for the existing shell plate; use 138 MPa (20,000 lbf/in.^{2}) if of unknown material. A joint efficiency of 1.0 may be used (see 9.9.5). The variable H shall be the height from the centerline of the penetration to the maximum liquid level, in ft.

9.9.3 Penetrations shall be prefabricated in thermally stress relieved insert assemblies when required by API 650, Section 5.7.4. API 650, Section 4.1.5, may be used when reinforcing material is from API 650 Group-IV through

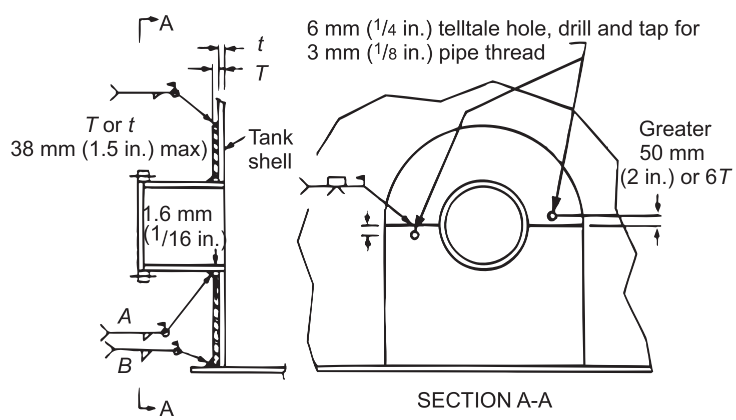


t and T (maximum)	A
14 mm	6 mm
20 mm	8 mm
24 mm	10 mm
27 mm	11 mm
33 mm	13 mm
40 mm	14 mm
45 mm	16 mm

t and T (maximum)	A
9/16 in.	1/4 in.
3/4 in.	5/16 in.
15/16 in.	3/8 in.
1 1/8 in.	7/16 in.
1 5/16 in.	1/2 in.
1 9/16 in.	9/16 in.
1 3/4 in.	5/8 in.

NOTE All details, dimensions, and weld spacing shall be in accordance with the requirements of API 650.

Figure 9.7—Typical Details for Addition of Reinforcing Plate to Existing Shell Penetration



t and T (maximum)	A	B
14 mm	6 mm	6 mm
20 mm	8 mm	6 mm
24 mm	10 mm	8 mm
27 mm	11 mm	8 mm
33 mm	13 mm	10 mm
40 mm	14 mm	10 mm
45 mm	16 mm	10 mm

t and T (maximum)	A	B
9/16 in.	1/4 in.	1/4 in.
3/4 in.	5/16 in.	1/4 in.
15/16 in.	3/8 in.	5/16 in.
1 1/8 in.	7/16 in.	5/16 in.
1 5/16 in.	1/2 in.	3/8 in.
1 9/16 in.	9/16 in.	3/8 in.
1 3/4 in.	5/8 in.	3/8 in.

NOTE All details, dimensions, and weld spacing shall be in accordance with the requirements of API 650.

Figure 9.8—Typical Details for Addition of "Tombstone" Shape Reinforcing Plate to Existing Shell Penetration

Group-VI and the existing shell is a Group-I through Group-IIIA material. When it cannot be reasonably ascertained in Section 11.1.2 that the existing materials correspond in strength to materials in API 650 Groups I through IIIA, then the rules of API 650, Section 5.7.4 that are applicable to Group-IV through Group-VI materials shall be satisfied, unless addressed by a plan reviewed and approved by a storage tank engineer.

9.9.4 For insert type penetrations, the following erection requirements shall be met:

a) if an integral reinforcement design is used with a thickened insert plate, the thickened insert plate at its periphery shall have a 1:4 reduction taper to match the nominal thickness of the adjoining shell material;

b) spacing of welds shall be in accordance with Figure 9.1;

c) the new insert plate or thickened insert plate shall be joined to the existing shell material with full penetration and full fusion butt welds.

9.9.5 Examinations shall be per Section 12, except penetrations located on a shell joint shall receive additional shell radiography in accordance with API 650, Section 5.7.3.4.

9.9.6 Penetrations larger than DN 100 (NPS 4) shall be installed with the use of an insert plate or thickened insert plate, if the shell plate thickness is greater than 13 mm ($^1/_2$ in.) and the shell plate material does not meet the current design metal temperature criteria. In addition, the following requirement shall be met:

a) for a circular insert plate or thickened insert plate, the minimum diameter shall be at least the greater of 1) twice the diameter of the opening in the insert plate that accommodates the radial oriented nozzle, or 2) the diameter of the opening in the insert plates plus 300 mm (12 in.);

b) for a noncircular insert plate or thickened insert plate, the minimum dimension across the insert plate from end to end in any direction (if other than circular), shall be at least the greater of 1) twice the dimension of the opening in the insert plate or thickened insert plate in that direction, or 2) the dimension of the opening in the insert plate or thickened insert plate in that direction plus 300 mm (12 in.).

9.10 Alteration of Existing Shell Penetrations

9.10.1 Existing shell penetrations may be altered if the altered details comply with the requirements of API 650, Section 5.7 including the requirements for minimum reinforcing area and the requirements for spacing of welds around connections.

9.10.2 When installing a new tank bottom above the existing bottom, it may be necessary to alter existing shell penetrations in the bottom course of a tank shell. If the new bottom is slotted through the tank shell several inches above the existing bottom, the spacing between existing welds around penetrations and the new bottom-to-shell weld may not comply with API 650 requirements. Options for altering the penetrations and/or reinforcing plates are given in 9.10.2.1 through 9.10.2.3.

9.10.2.1 The existing reinforcing plate may be trimmed to increase the spacing between the welds provided that the altered detail complies with the requirements of API 650, Section 5.7. Care must be exercised during the trimming operation to avoid damaging the shell material beneath the reinforcing plate. The existing weld attaching the portion of the reinforcing plate to be removed shall be completely removed by gouging and grinding. The required spacing of the welds may be reduced per 9.11.2.7(a) or (b) if the requirements of 9.11.2.7(c), (d), and (e) are met.

9.10.2.2 The existing reinforcing plate may be removed and a new reinforcing plate added except that reinforcing plate replacement is not permitted in existing stress relieved assemblies unless the requirements of 11.3 are met. If it is not known whether the assembly was thermally stressed relieved, then the alteration shall meet the requirements of API 650, Section 5.7.4. Care must be exercised when removing the existing reinforcing plate to avoid damaging the shell plate beneath the reinforcing plate. When the upper half of the existing reinforcing plate meets all requirements of API 650, it can be left in place with approval of the purchaser. In this case, only the lower half of the existing reinforcing plate need be removed and replaced with the new one. The existing upper half of the reinforcing plate and the new lower section shall be provided with a new telltale hole, if needed, or drilled hole, and a welded pipe; coupling for the pneumatic test. The shell plate thickness under the telltale hole or drilled hole shall be checked after drilling and the thickness shall not be less than $^1/_2 t_{min}$, as calculated in 4.3.3.1, plus any required corrosion allowance. The welds to be replaced around the perimeter of the reinforcing plate and between the reinforcing plate and neck of the penetration shall be completely removed by gouging and grinding. The new reinforcing plate shall be in accordance with Figure 9.7. If required to maintain weld spacing, a tombstone-shaped reinforcing plate may be used (see Figure 9.8). All reinforcement plate seam welds shall be in the horizontal position, with seam at the shell penetration horizontal centerline, as shown in Figures 9.7 and 9.8.

9.10.2.3 The existing penetration may be moved by cutting the section of the shell containing the fitting and reinforcing plate, and raising the entire assembly to the correct elevation (see Figure 9.9). The new shell seams made to raise the penetration shall comply with Figure 9.1, including the shell to bottom seam.

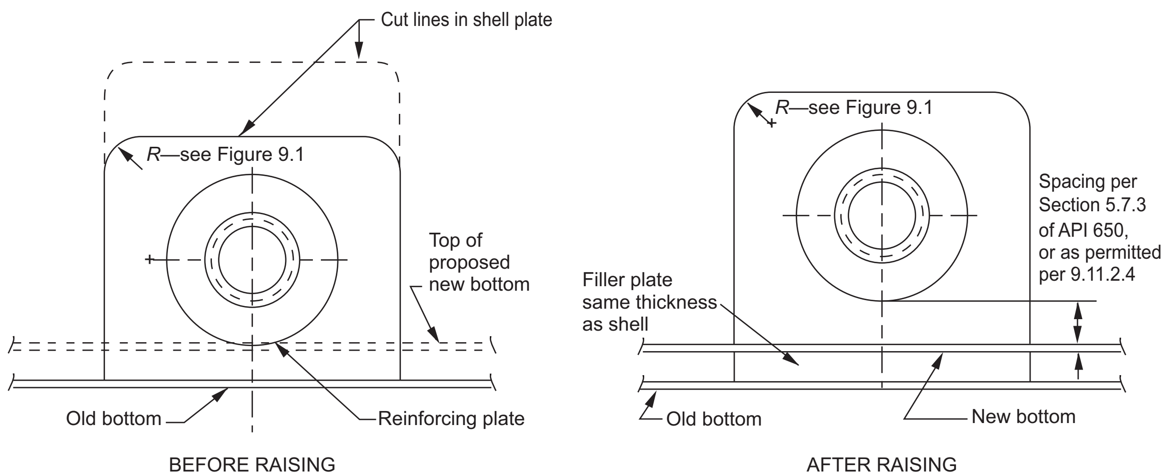


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Figure 9.9—Method for Raising Shell Nozzles

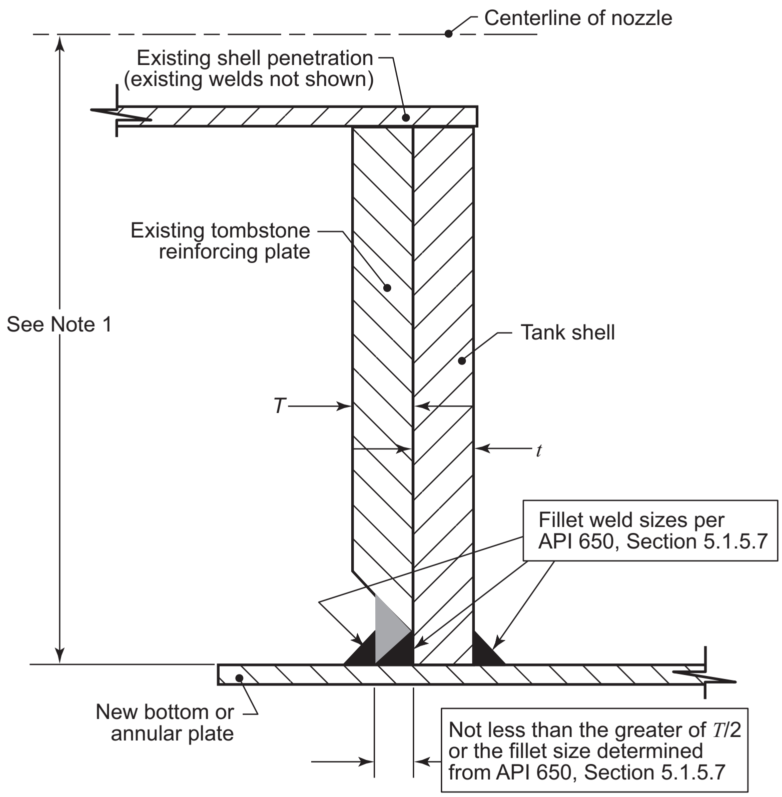
9.10.3 Any components of the penetration (neck, flange, and reinforcing plate) that are in serviceable condition after removal may be reused.

9.10.4 A new bottom may be installed through an existing tombstone reinforcing plate, provided all weld spacing and reinforcement requirements, as specified in API 650, are met. One of the following methods shall be used.

a) Remove only that portion of the existing reinforcing plate necessary to weld and test the new bottom-to-shell weld. The lower edge of the reinforcing plate shall be cut reasonably straight and horizontal and beveled to facilitate welding. See Figure 9.10 for weld joint details.

b) Bevel the shell from the inside to allow for a full penetration weld between the bottom and shell. This method shall only be used on tanks where the annular plate or bottom sketch plate thickness is equal to or greater than 10 mm ($^3/_8$ in.). This weld detail shall be used along the full width of the reinforcing plate and shall extend a minimum of 25 mm (1 in.) beyond the edges of the reinforcing plate. Once beyond the reinforcing plate, the full penetration weld shall tie in to the outside shell-to-bottom fillet weld to create a "water stop" and then transition to the typical shell-to-bottom weld detail. See Figure 9.11 for weld joint details.

c) The bottom portion of the reinforcing plate may be removed using a horizontal cut between the bottom invert of the nozzle neck and the new bottom per requirements of Figure 9.12. The removed (or new) reinforcing



NOTE 1 In using this detail, it must be confirmed that the distance from top of new bottom to center of nozzle meets API 650, Table 5.6a or Table 5.6b.

NOTE 2 All welds shown shall be individually examined to API 650, Section 7.2.4.

Figure 9.10—Details for Installing a New Bottom Through an Existing Tapered Tombstone

plate shall be prepared for a full fusion splice weld with telltale hole added (see Figure 9.12). The removed (or new) reinforcing plate shall be reinstalled after the shell-to-bottom weld has been completed, inspected, and tested. The splice weld shall be made prior to the reinforcing plate weld to bottom plate weld. The completed splice weld shall be magnetic particle examined.

d) The lower portion of the existing reinforcing plate may be removed and reinstalled after the new shell-to-bottom weld is complete. The existing reinforcing plate shall be cut at the horizontal centerline of the nozzle. Telltale holes are required in both parts of the reinforcing plate (see Figure 9.8).

e) The existing reinforcing plate may be removed, modified and reinstalled after the new shell-to-bottom weld is complete (see Figure 9.8).

NOTE 1 Options d) and e) are not permitted on existing post-weld heat treated nozzles unless the requirements of 11.3 are met.

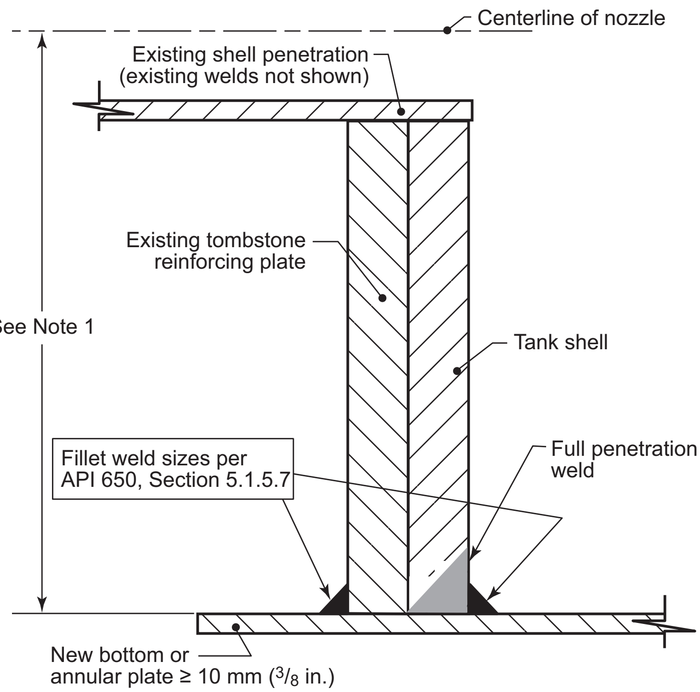
NOTE 2 To minimize damage to the shell plate such that repairs can be made, care must be exercised when removing the existing reinforcing plate.

9.11 Repair of Tank Bottoms

9.11.1 Repairing a Portion of Lap-welded or Butt-welded Tank Bottoms

9.11.1.1 General Repair Requirements

The use of welded-on patch plates for repairing a portion of uniformly supported tank bottoms is permitted within the limitations given in this section and 9.11.1.2. See Figure 9.13 for acceptable details for welded-on patch plates.



NOTE 1 In using this detail, it must be confirmed that the distance from top of new bottom to center of nozzle meets API 650, Table 5.6a or Table 5.6b.

NOTE 2 All welds shown shall be individually examined to API 650, Section 7.2.4.

Figure 9.11—Details for Installing a New Bottom Through an Existing Tombstone Reinforcing Plate with a Tapered Shell

a) The minimum dimension for a welded-on patch plate that overlaps a bottom seam or existing patch is 300 mm (12 in.). The welded-on patch plate may be circular, oblong, or polygonal with rounded corners.

b) The minimum patch plate thickness that is less than the nominal thickness of the existing bottom should be calculated per 4.4.5.1 and approved by the owner/operator.

c) A welded-on patch plate smaller than 300 mm (12 in.) in diameter is permitted if: it does not overlap a bottom seam; it is not; placed fully or partially over an existing patch; and it extends beyond the corroded bottom area, if any, by at least 50 mm (2 in.). This patch plate must be no smaller than 150 mm (6 in.) across in any direction.

d) Welded-on patch plates shall not be placed over areas of the tank bottom that have global dishing, local dishing [except as allowed by 9.11.1.1 e)], settlement, or distortion greater than the limits of Annex B.

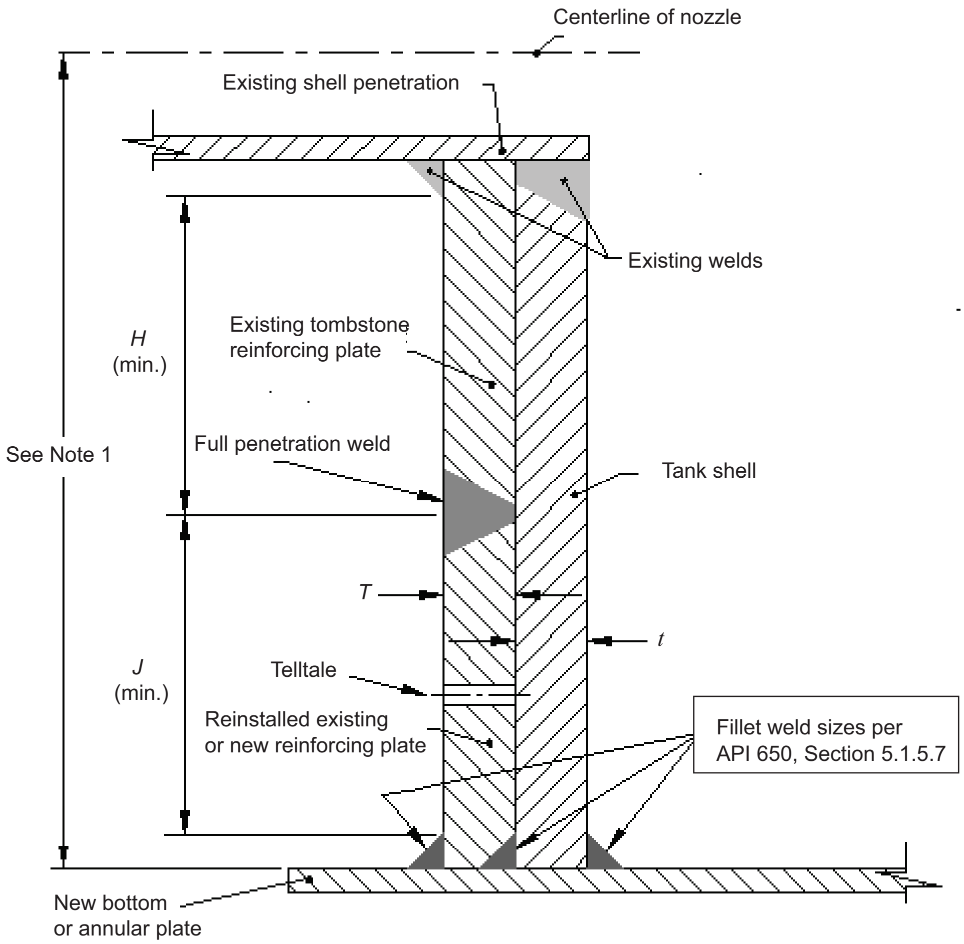
NOTE If the tank is still undergoing settlement, the addition of welded-on patch plate may not be advisable.

e) A welded-on patch plate may be placed over a mechanical dent or local dishing if: its unsupported dimension does not exceed 300 mm (12 in.) in any direction; it is at least 6 mm (1/4 in.) thick; it is at least as thick as the existing bottom; and does not overlap seams nor other patches, except for tanks designed in accordance with API 650, Annex M, which shall have welded-on patch plates at least 10 mm (3/8 in.) thick.

f) These repairs are permanent repairs subject to an on-going inspection and maintenance program.

g) Installation of a new sump shall conform to the following in API Standard 650: Section 5.8.7, Tables 5.16a and 5.16b, and Figure 5.21.

h) Dimensions given are from toe of fillet welds or to the centerline of the butt weld, and also apply to new-to-existing welds.



Material	Thickness	*H* (the larger of)	*J* (the larger of)
Case 1, 2, and 3	$t \leq$ 13 mm (1/2 in.)	75 mm (3 in.)	75 mm (3 in.)
Case 1:	$t >$ 13 mm (1/2 in.)	75 mm (3 in.) or 2 1/2 t	75 mm (3 in.) or 4tw
Case 2:	$t >$ 13 mm (1/2 in.)	100 mm (4 in.) or 4t	75 mm (3 in.) or 4tw
Case 3:	$t >$ 13 mm (1/2 in.)	125 mm (5 in.) or 4t	125 mm (5 in.) or 4tw

where tw is the required weld size from API 650, Section 5.1.5.7.

Case 1—Shell material meets API 650, Seventh Edition or later toughness requirements and opening was PWHT'd.

Case 2—Shell material meets API 650, Seventh Edition or later toughness requirements.

Case 3—Shell material does not meet API 650, Seventh Edition or later toughness requirements.

NOTE 1 In using this detail, it must be confirmed that the distance from top of new bottom to center of nozzle meets API 650, Table 5.6a or Table 5.6b and that additionally there is sufficient space to provide the minimum *H* and *J* spacings.

NOTE 2 All welds shown shall be individually examined to API 650, Section 7.2.4.

Figure 9.12—Details for Installing a New Bottom Through an Existing Tombstone Reinforcing Plate

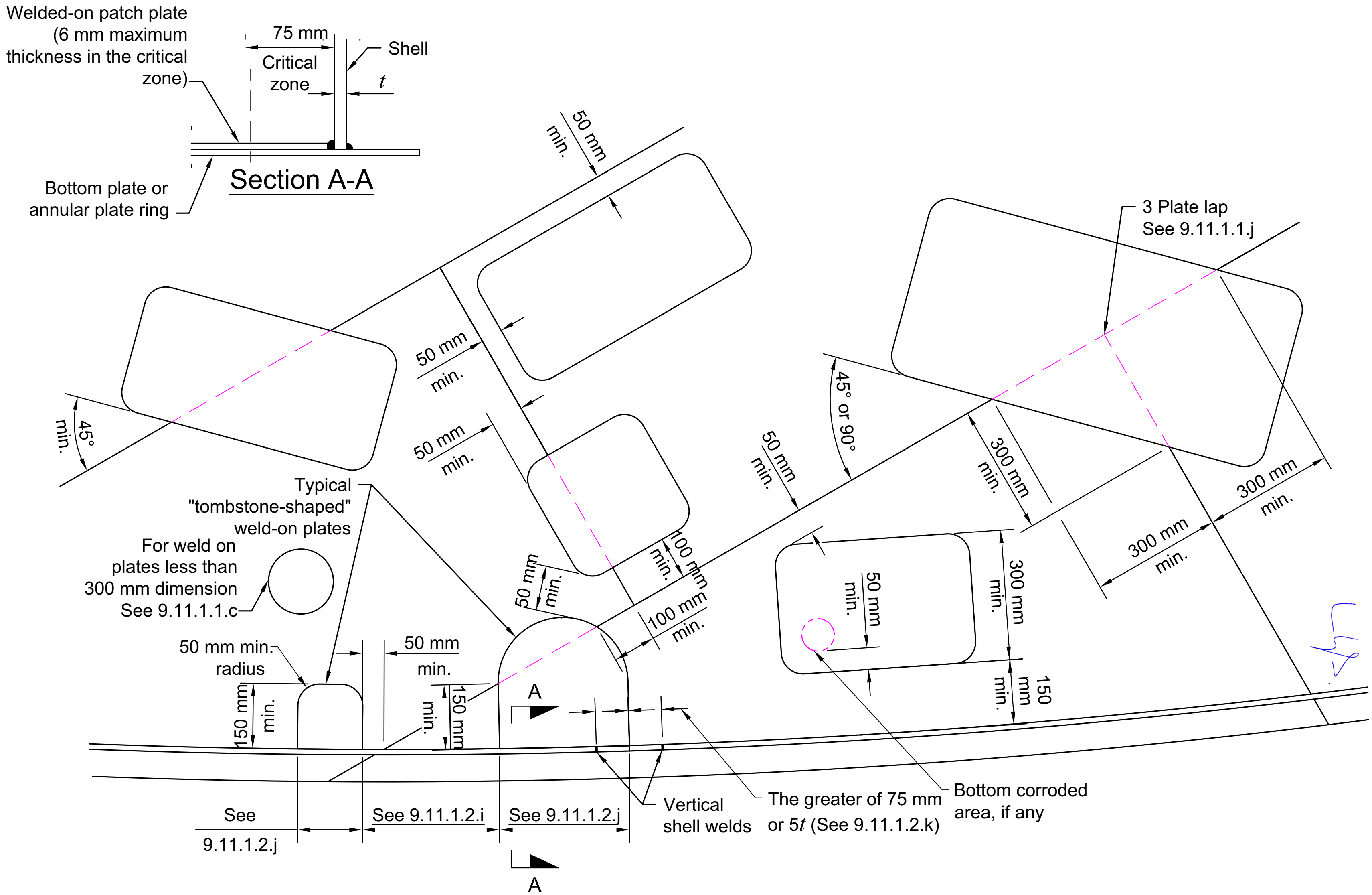


Figure 9.13a—Typical Welded-on Patch Plates on Tank Bottom Plates, in SI Units

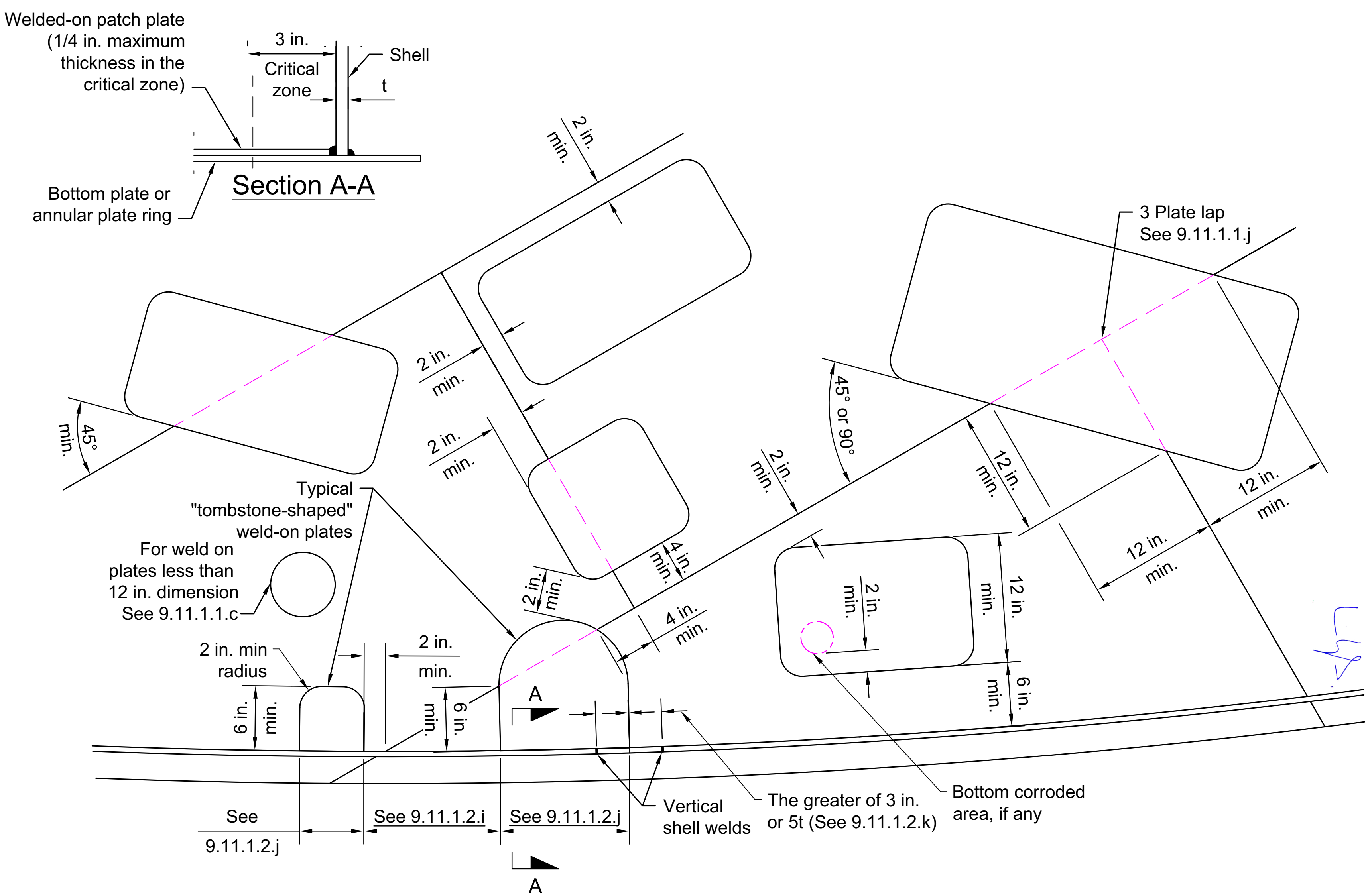


Figure 9.13b—Typical Welded-on Patch Plates on Tank Bottom Plates, in USC Units

i) When the edge of a welded-on patch plate is approximately parallel to a bottom seam, the edge shall be held at least 50 mm (2 in.) from weld seam. Patch plates not crossing an existing bottom lap joint shall be no closer than 50 mm (2 in.) from any other bottom lap weld.

j) Patch plates covering 3-plate laps shall extend a minimum of 300 mm (12 in.) in all directions along all bottom lap welds beyond the 3-plate lap.

k) Patch plates crossing an existing bottom lap weld shall be no closer than 100 mm (4 in.) to an adjacent 3-plate lap.

l) Patches crossing existing bottom lap seams must cross creating an angle of no less than 45 degrees. Patches over three-plate lap joints shall cross the seams at either 45 degrees or 90 degrees.

m) Patch plates shall be seal welded to the bottom with full-fillet welds.

9.11.1.2 Repairs within the Critical Zone

The use of welded-on patch plates is permitted for repairing a portion of tank bottoms within the critical zone (see 3.10 for definition) provided 9.11.1.1 requirements and the following additional requirements are met.

a) Maximum plate thickness for welded-on patch plates within the critical zone is 6 mm ($^1/_4$ in.) and must meet the toughness requirements of API 650, Section 4.2.10.

b) When a welded-on patch plate is within 150 mm (6 in.) of the shell, the welded-on patch plate shall be tombstone shaped. The sides of the tombstone shaped welded-on patch plate shall intersect the shell-to-bottom joint at approximately 90°.

c) Perimeter welds on welded-on patch plates within the critical zone shall be two-pass, minimum, and examined per 12.1.1.3 and 12.1.7.2.

d) Installation of a welded-on patch plate by butt-welding to an adjacent existing patch is not permitted in the critical zone.

e) Welded-on patch plates over existing patches are not allowed in the critical zone.

f) The bottom plate under the perimeter of a welded-on patch plate shall meet the thickness requirements in 4.4.

g) For tanks with shell plate of unknown toughness (defined in Section 3), new fillet welds utilized to install a tombstone patch plate in the critical zone shall be spaced at least the greater of 75 mm (3 in.) or $5t$ from existing vertical weld joints in the bottom shell course, where t is the thickness of the bottom shell course, in millimeters (inches). See Figure 9.13 for further guidance on weld spacing.

h) Minimum dimension between two welded-on patch plates in the critical zone shall be one-half of the dimension approximately parallel to the shell of the smaller patch.

i) The maximum dimension along the shell for welded-on patch plates in the critical zone is 600 mm (24 in.).

j) Dimensions to vertical shell welds apply to shells of unknown toughness.

NOTE The bottom plate thickness at the attachment weld must be at least 2.5 mm (0.10 in.) thick before welding the welded-on patch plate to the bottom plate. Refer to API 2207 for further information.

9.11.1.2.1 No welding or weld overlays are permitted within the critical zone except for the welding of: widely scattered pits (see 4.3.2.2), pinholes, cracks in the bottom plates, the shell-to-bottom weld, welded-on patch plates, or where the bottom plate welded to the shell is being replaced.

9.11.1.2.2 A welded-on patch plate shall not be used if the covered bottom plate minimum remaining thickness at the toe of the internal shell-to-bottom weld will be less than the minimum thickness required by 4.4.5 and 4.4.6 at the next internal inspection.

9.11.1.2.3 Welded-on patch plates are not permitted in the critical zone on a tank bottom with an operating temperature exceeding 200 °F for carbon steel or 100 °F for stainless steel.

9.11.1.2.4 If more extensive repairs are required within the critical zone than those listed in 9.11.1.2, the bottom plate welded to the shell shall be cut out and a new plate shall be installed. Weld spacing requirements shall be in accordance with 9.11.2.4, and API 650, Section 5.1.5.4 and Section 5.1.5.5. The shell-to-bottom weld shall be removed and replaced for a minimum distance of 300 mm (12 in.) on each side of the new bottom plate.

9.11.1.3 The use of welded-on patch plates that do not meet the requirements of 9.11.1.1 or 9.11.1.2 is permitted if the repair method has been reviewed and approved by an engineer experienced in storage tank design in accordance with API 650. The review shall consider brittle fracture, stress due to settlement, stress due to shell bottom discontinuity, metal temperature, fracture mechanics, and the extent and quality of NDE.

9.11.1.4 Unacceptable indications such as cracks, gouges, tears, and corroded areas discovered in bottom plates, located outside the critical zone, may be repaired by deposition of weld metal followed by examination and testing in accordance with 12.1.7.3. Surface irregularities and contamination within the area to be repaired shall be removed before welding.

9.11.1.5 The repair of sumps located within the critical zone shall be in accordance with 9.11.1.2.

9.11.1.6 The repair of corroded plates in the critical zone is limited to pit welding or overlay welding as noted in this section. The weld repair of bottom plate corrosion is permitted if all of the following conditions are satisfied.

a) The sum of the pit dimensions along an arc parallel to the shell-to-bottom joint does not exceed 50 mm (2 in.) in a 200 mm (8 in.) length.

b) There must be sufficient remaining bottom plate thickness for completion of a sound weld and to avoid burn-through. The minimum acceptable bottom plate thickness for weld repairs is 2.5 mm (0.10 in.). A lesser thickness is permitted for weld repairs only if reviewed and approved by an engineer experienced in storage tank design and repair.

c) All weld repairs shall be ground flush with the surrounding plate material and be examined in accordance with 12.3.3.4.

9.11.2 Replacement of Tank Bottom Plates

9.11.2.1 Requirements governing the installation of a replacement bottom over an existing bottom are given in 9.11.2.1.1 through 9.11.2.1.5.

9.11.2.1.1 Suitable noncorrosive material cushion such as sand, gravel, or concrete shall be used between the old bottom and the new bottom.

9.11.2.1.2 The shell shall be slotted with a uniform cut made parallel to the tank bottom. The cut edges in the slot shall be ground to remove all slag and burrs from cutting operations. The new bottom plate shall extend outside the shell as required by API 650, Section 5.4.2. All rules for weld spacing shall be followed.

9.11.2.1.3 Voids in the foundation below the old bottom shall be filled with sand, crushed limestone, grout, or concrete.

9.11.2.1.4 Except as permitted in 9.11.2.7, existing shell penetrations shall be raised or their reinforcing plates modified if the elevation of the new bottom results in inadequate nozzle reinforcement details (see Figure 9.8 and API 650, Section 5.7.2) or if the weld spacing requirements given in API 650, Section 5.7.3 are not met.

9.11.2.1.5 For floating roof tanks, the new bottom profile must keep the roof level when it is resting on its support legs. The levelness of the floating roof can be adjusted by changing the length of the support legs. The support legs can either remain the same length to maintain the original height above the bottom or be shortened by the same amount as the thickness of the cushion and new bottom plate.

9.11.2.2 New bearing plates for fixed roof support columns shall be installed. For steel floating roof legs, steel pads or other means shall be used to distribute the loads on the bottom of the tank and provide a wear surface. If pads are used, they shall be continuously welded to the tank bottom. For aluminum floating roofs, the pads may be omitted if the owner-operator approves and new austenitic stainless steel or acceptable nonmetallic (e.g., Teflon) spacers are installed to isolate legs from the carbon steel bottom. For aluminum floating roofs, austenitic stainless steel or acceptable non-metallic (e.g., Teflon) spacers may installed to isolate legs from the carbon steel bottom instead of welded pads if the spacers will not damage bottom coatings, there is no evidence of corrosion damage from such spacers on the previous bottom, and if the owner/operator approves.

9.11.2.3 When removing an existing tank bottom, the tank shell shall be separated from tank bottom either by:

a) cutting the shell parallel to the tank bottom a minimum of 13 mm ($^1/_2$ in.) above the bottom-to-shell weld (cut line B-B as shown in Figure 10.1), or

b) removing the entire shell-to-bottom attachment weld, including any penetration and heat affected zone by suitable methods such as arc gouging and/or grinding.

All arc-gouged areas of the tank shell-to-bottom weld shall be magnetic particle examined, and defective areas repaired and re-examined.

9.11.2.4 Installation of a new tank bottom, after removal of the existing tank bottom, shall meet all requirements of API 650. Except as permitted in 9.11.2.7, existing shell penetrations shall be raised or their penetration reinforcing plates modified if the elevation of the new bottom results in inadequate nozzle reinforcement (see Figure 9.8 and API 650, Section 5.7.2) or if the weld spacing requirements given in API 650, Section 5.7.3 are not met. For tanks with shell plate of unknown toughness as defined in Section 3, new weld joints in the bottom or annular ring shall be spaced at least the greater of 75 mm (3 in.) or $5t$ from existing vertical weld joints in the bottom shell course, where t is the thickness of the bottom shell course, in inches.

9.11.2.5 Replacement of portions of an existing tank bottom (entire rectangular plates or large segments of plates) not within the critical zone (see 3.10 for definition) are permitted under the same rules that govern installation of bottoms in new tank construction per API 650, Sections 5.4 and 5.5.

9.11.2.6 The following shall be considered for tanks with cathodic protection and under-bottom leak detection.

a) For tanks having cathodic protection (CP) installed under the existing bottom, consideration shall be given to removal of the entire bottom and unused dead shell to prevent shielding of CP current to the new bottom. Removal of the old bottom is also important in preventing galvanic corrosion (refer to API 651). Where this is possible, removal of the entire old bottom, except the unused dead shell and not more than 450 mm (18 in.) of bottom annulus attached to the shell, shall be considered.

b) Consideration shall be given to installing under-bottom leak detection at this time (such as an RPB) to contain and channel any bottom leak to a location where it can readily be observed from outside of the tank. See 4.4.3.5 and Annex I.

9.11.2.7 For tanks constructed from materials having 345 MPa (50,000 lbf/in.^{2}) yield strength or less, the required spacing of the welds may be reduced from the requirements of 9.11.2.4 if the following conditions are met.

a) For reinforced penetrations, including low-types, a minimum of 100 mm (4 in.) shall be maintained between the shell-to-bottom weld toe and the nearest penetration attachment weld toe (reinforcing plate periphery weld, or nozzle neck weld to low type reinforcing plate and shell welds).

b) For self-reinforced penetrations, the greater of 75 mm (3 in.) or $2^1/_2t$ shall be maintained between the shell-to-bottom weld toe and the nearest penetration attachment weld toe.

c) The following shall be welded with low hydrogen electrodes and with welding procedures that are designed to limit distortion and residual stress:

i) shell-to-bottom weld,

ii) re-welding of trimmed reinforcing plate per 9.10.2.1.

d) The toes of the welds shall be blend-ground to minimize stress concentrations as follows:

i) For circular reinforcing plates, blend-grind the periphery attachment weld from the “four o'clock” position to the “eight o'clock” position. Blend-grind the inside and outside of the shell-to-bottom weld a minimum of one penetration diameter length on either side of the penetration centerline.

ii) For diamond-shaped reinforcing plates, blend-grind the lower horizontal length of the diamond shaped attachment weld. Blend-grind the inside and outside of the shell-to-bottom weld a minimum of one penetration diameter length on either side of the penetration centerline.

iii) For low-type penetrations, blend-grind the nozzle attachment weld (shell and reinforcing plate) from the “four o'clock” position to the “eight o'clock” position. Blend-grind the inside and outside of the shell-to-bottom weld a minimum of one penetration diameter length on either side of the penetration centerline.

e) The blend-ground lengths of welds listed in 9.11.2.7(d) shall be magnetic particle examined. If a hydrotest is required by 12.3, this examination shall be performed before and after hydrostatic test.

9.11.3 Additional Welded-on Plates

9.11.3.1 If other welded-on plates, such as wear, isolation, striker, and bearing plates, are to be added to tank bottoms, they shall be installed in accordance with 9.11.1, and examined in accordance with 12.1.7. For these additional welded-on plates, if the lap-weld spacing requirements in Figure 9.13 are not met, magnetic particle (MT) or liquid penetrant (PT) examination is required for the exposed welds, or portions of welds, failing to meet minimum spacing criteria. See Section 12 for acceptance requirements.

9.11.3.2 Welded-on plates that fall within the critical zone (see 3.10 for definition) shall be installed in accordance with 9.11.1.2 and comply with all of its requirements.

9.12 Repair of Fixed Roofs

9.12.1 Repairs

9.12.1.1 Roof repairs involving tank venting shall be made such that normal and emergency venting meet the requirements of API 650, Section 5.8.5.

9.12.1.2 Roof repairs involving modification of the roof structure and the frangible joint (if applicable) shall be in compliance with the requirements of API 650, Section 5.10.

9.12.2 Supported Cone Roofs

9.12.2.1 The minimum thickness of new roof plates shall be 5 mm ($^3/_{16}$ in.) plus any corrosion allowance as specified in the repair specifications. In the event roof live loads in excess of 1.2 kPa (25 lbf/ft^2) are specified (such as insulation, operating vacuum, high snow loads), the plate thickness shall be based on analysis using the allowable stresses in conformance with API 650, Section 5.10.3 (see 9.12.2.2).

9.12.2.2 The roof supports (rafters, girders, columns, and bases) shall be repaired or altered such that under design conditions the resulting stresses do not exceed the stress levels given in API 650, Section 5.10.3.

9.12.3 Self-supporting Roofs

9.12.3.1 The nominal thickness of new roof plate shall be 5 mm ($^3/_{16}$ in.) or the required plate thickness given in API 650, Section 5.10.5 or Section 5.10.6, plus any specified corrosion allowance, whichever is greater.

9.12.3.2 The details of the roof-to-shell junction shall meet the requirements of API 650, Section 5.10.5; API 650, Section 5.10.6; or API 650, Annex F, as applicable, for the intended service.

9.13 Repair of Floating Roofs

9.13.1 External Floating Roofs

Any method of repair is acceptable that will restore the roof to a condition enabling it to perform as required.

9.13.2 Internal Floating Roofs

Repairs to internal floating roofs shall be made in accordance with the original construction drawings, if available. If the original construction drawings are not available, the roof repairs shall be in compliance with the requirements of API 650, Annex H.

9.13.3 Repair of Leaks in Pontoons

All leaks in pontoons or compartments of double deck floating roofs shall be repaired by re-welding the leaking joints and/or use of patch plates.

9.14 Repair or Replacement of Floating Roof Perimeter Seals

9.14.1 Primary Seals

Rim-mounted primary shoe seals and toroidal seal systems can be removed, repaired, or replaced. To minimize evaporation losses and reduce potential hazard to the workers, no more than one-fourth of the roof seal system should be out of an in-service tank at one time. Temporary spacers to keep the roof centered shall be used during the repairs. Primary seal systems mounted partly or fully below the bolting bar or top of the rim usually cannot be reached to allow removal in service. In this case, in-service repairs are limited to replacement of the primary seal fabric.

9.14.2 Secondary Seals

Rim-mounted and shoe-mounted secondary seals may be readily installed, repaired, or replaced while the tank is in service.

9.14.3 Seal-to-shell Gap

Repair and other corrective actions to maintain seal-to-shell gap requirements, include the following.

a) Adjusting the hanger system on primary shoe seals, and adding foam filler in toroidal seals.

b) Increasing the length of rim mounted secondary seals in the problem area.

c) Replacing all or part of the primary seal system along with possible installation of a rim extension for a secondary seal. This step shall be taken only after checking the annular space variation at several levels from low pump out to high liquid level.

9.14.4 Mechanical Damage

Damaged parts shall be repaired or replaced. Prior to taking this action, the cause of the damage shall be identified and corrected. Buckled parts shall be replaced, not straightened. Torn seal fabric shall be replaced.

9.14.5 Deterioration of Seal Material

Material deterioration results from wear and corrosion on metallic elements, and chemical and weather deterioration of seal fabric. The service life and inspection information shall be used to determine whether a change of material is warranted.

9.14.6 Installation of Primary and Secondary Seals

9.14.6.1 The replacement or addition of primary and secondary seals shall be in accordance with the recommendations of the seal manufacturer. In addition, the final installation shall comply with all applicable jurisdictions.

9.14.6.2 If the roof rim thickness is less than 2.5 mm (0.10 in.) thick, it shall be replaced. The new roof rim shall be 5 mm ($^{3}/_{16}$ in.) thickness, minimum.

9.15 Hot Taps

9.15.1 General

9.15.1.1 The requirements given herein cover the installation of radial hot tap connections on existing in-service tanks. Hot taps on shell material that would normally require thermal stress relief per API-650 Section 5.7.4 are permitted without PWHT if welding is qualified and performed in accordance with a controlled-deposition welding method meeting the requirements of API 653 Section 11.3.2 plus the addition that the weld qualification tests shall be performed with water backing.

a) For tank shell plates of recognized toughness (defined in Section 3), the connection size and shell thickness limitations are shown in Table 9.1.

Table 9.1a—Hot Tap Connection Sizes and Shell Plate Thicknesses, in SI Units

Connection Size, DN	**Minimum Shell Plate Thickness** (mm)
<150	5
≤ 200	6
≤ 250	8
≤ 350	10
≤ 400	11
≤ 450	13

Table 9.1b—Hot Tap Connection Sizes and Shell Plate Thicknesses, in USC Units

Connection Size, NPS (in.)	**Minimum Shell Plate Thickness** (in.)
≤ 6	$^{3}/_{16}$
≤ 8	$^{1}/_{4}$
≤ 10	$^{5}/_{16}$
≤ 14	$^{3}/_{8}$
≤ 16	$^{7}/_{16}$
≤ 18	$^{1}/_{2}$

b) For tank shell plates of unknown toughness (defined in Section 3), the following limitations apply.

1) Nozzles shall be limited to a maximum diameter of DN 100 (NPS 4).

2) The shell plate temperature shall be at or above the minimum shell design metal temperature for the entire hot tapping operation.

3) All nozzles shall be reinforced. The reinforcement shall be calculated per API 650, Section 5.7.2. The minimum thickness of the reinforcing plate shall be equal to the shell plate thickness, and the minimum reinforcing plate diameter shall not be less than the diameter of the shell cutout plus 50 mm (2 in.).

4) The maximum height of tank liquid above the hot tap location during the hot tapping operation shall be such that the hydrostatic tank shell stress is less than 48 MPa (7000 lbf/in.^{2}) at the elevation of the hot tap.

9.15.1.2 The minimum height of tank liquid above the hot tap location shall be at least 0.9 m (3 ft) during the hot tapping operation.

9.15.1.3 Welding shall be done with low hydrogen electrodes.

9.15.1.4 Hot taps are not permitted on the roof of a tank or within the gas/vapor space of the tank.

9.15.1.5 Hot taps shall not be installed on laminated or severely pitted shell plate.

9.15.1.6 Hot taps are not permitted on tanks where the heat of welding may cause environmental cracking (such as caustic cracking or stress corrosion cracking).

9.15.1.7 Reinforcing plates for hot-tapped nozzles shall not cross any shell plate seams or extend to the shell-to-bottom joint weld; see Figure 9.14.

9.15.2 Hot Tap Procedures

A hot tap procedure specific to carrying out the work shall be developed and documented. The procedure shall include the practices given in API 2201.

9.15.3 Preparatory Work

9.15.3.1 Minimum spacing in any direction (toe-to-toe of welds) between the hot tap and adjacent nozzles shall be equivalent to the square root of RT where R is the tank shell radius, in inches, and T is the shell plate thickness, in inches.

9.15.3.2 Shell plate thickness measurements shall be taken at a minimum of four places along the circumference of the proposed nozzle location.

9.15.4 Material Limitations

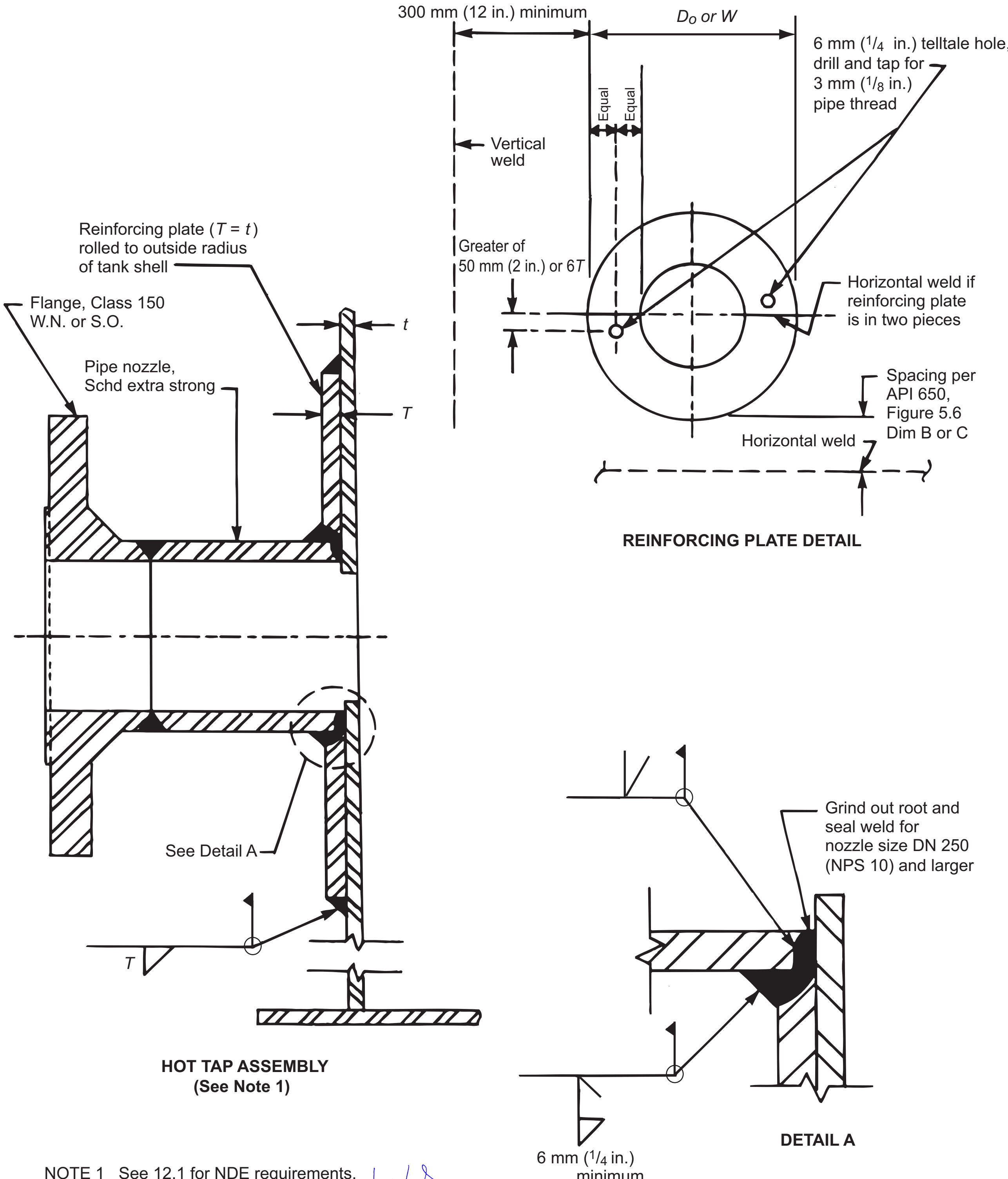
Only hot tap steels of recognized toughness (defined in Section 3), unless the additional requirements of 9.15.1.1 b) are met.

9.15.5 Installation Procedure

9.15.5.1 Pipe nozzles shall be cut to the contour of the shell and beveled from the outside for a full penetration weld (see Figure 9.14). The nozzle neck-to-shell weld shall be examined in accordance with 12.1.2.3.

9.15.5.2 After the pipe is welded, the reinforcing plate shall be installed either in one piece or two pieces with horizontal weld. The reinforcing plate to nozzle shall be installed with a full penetration weld. Care shall be taken to limit the heat input to the welds.

9.15.5.3 After the reinforcing plate has been welded to the shell and NDE performed, the pad shall be pneumatically tested by the procedure described in API 650, Section 7.3.5. After the valve has been installed on the flange, a pressure test at least 1.5 times the hydrostatic head shall be performed on the nozzle prior to mounting the hot tap



NOTE 1 See 12.1 for NDE requirements.

Figure 9.14—Hot Tap for Tanks

machine, which shall be bolted to the valve. The required pressure for the pressure test shall be at least the value computed by the following equation:

In SI units: $P_{(kPa)} = 1.5H_2G\gamma_w a/1000$

where

H_2 is the height of tank shell in meters;

G is the specific gravity of product stored;

γ_w is the mass density of water, which is 1000 kg/m^3;

a is the acceleration of gravity, which is 9.8 m/s^2.

In USC units: $P_{(\mathrm{psi})} = 1.5H_2G\gamma_w/144$

where

H_2 is the height of tank shell in feet;

G is the specific gravity of product stored;

γ_w is the weight density of water, which is 62.4 lb/ft^3.

9.15.5.4 A qualified operator shall operate the hot tap machine and cut the hole in the tank following the hot tap machine manufacturer's procedures.

SECTION 10—DISMANTLING AND RECONSTRUCTION

10.1 General

10.1.1 This section provides procedures for dismantling and reconstructing existing welded tanks that are to be relocated from their original site.

10.1.2 Hydrostatic testing requirements, NDE requirements, and acceptance criteria for the quality of welds for reconstructed tanks are specified in Section 12.

10.1.3 All reconstruction work must be authorized by the authorized inspector or an engineer experienced in storage tank design, prior to commencement of the work by a reconstruction organization (see 3.31). The authorized inspector will designate inspection hold points required during the reconstruction process and minimum documentation to be submitted upon job completion.

10.1.4 The authorized inspector or an engineer experienced in storage tank design shall approve all reconstruction work at the designated hold points and after reconstruction has been completed in accordance with the requirements of this standard.

10.2 Cleaning and Gas Freeing

The tank shall be cleaned and gas-freed prior to commencement of dismantling.

10.3 Dismantling Methods

10.3.1 General

Roof, shell, and bottom plates may be cut into any size pieces that are readily transportable to the new site for reconstruction.

10.3.2 Bottoms

10.3.2.1 Bottom plates that will be reused shall be cut by deseaming of lap welds; or by cutting alongside of the remaining welds at a minimum of 50 mm (2 in.) away from existing welds, except where cuts cross existing weld seams.

10.3.2.2 If the bottom is to be used, one of the following methods is acceptable:

a) the bottom plates may be cut from the shell along a line *A-A* and line *B-B* shown in Figure 10.1, scrapping the welds and the bottom plate directly attached to the shell;

b) if the entire bottom is to be reused, the bottom may be cut from the shell on the line *C-C* leaving the shell with part of the bottom attached;

c. if the tank has an existing butt-welded annular ring, this ring can be left attached to the shell or removed from the shell by cutting out along line *B-B* or otherwise removing the existing shell to annular ring welds.

10.3.3 Shells

10.3.3.1 Tank shell plates may be dismantled using one of the following methods or a combination thereof.

a) Any shell ring may be dismantled by cutting out existing weld seams and the heat affected zone (HAZ) of the weld. For the purpose of this method, the minimum HAZ to be removed will be $^1/_2$ of the weld metal width or 6 mm ($^1/_4$ in.), whichever is less, on both sides of the weld seam.

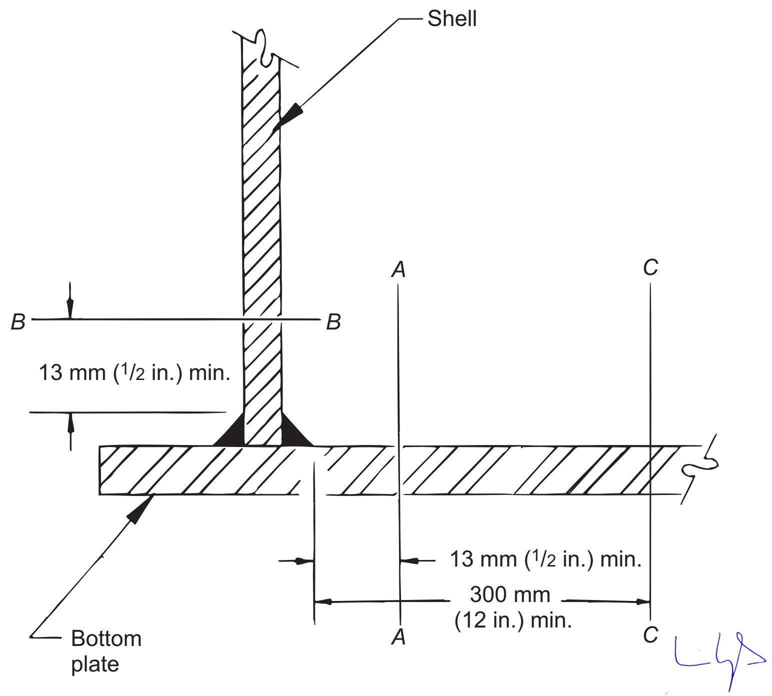


Figure 10.1—Tank Shell and Bottom Cut Locations

b) Any shell ring 13 mm (1/2 in.) thick or thinner may be dismantled by cutting through the weld without removing the HAZ.

c) Shell rings may be dismantled by cutting vertical and/or horizontal cuts through the shell a minimum of 150 mm (6 in.) away from existing welds, except where cuts cross existing welds.

10.3.3.2 Shell stiffening rings, including wind girders and top angles, may be left attached to the shell plates or may be removed by cutting at the attachment welds. The area where temporary attachments are removed shall be ground flush with the shell plate.

10.3.3.3 The shell shall be cut from the bottom plate along line *B*-*B* as shown in Figure 10.1. The existing shell-to-bottom weld connection shall not be reused unless the entire bottom is to be reused intact.

10.3.4 Roofs

10.3.4.1 Roof plates shall be cut by deseaming of lap welds, or by cutting alongside of the remaining welds at a minimum of 50 mm (2 in.) away from existing welds, except where cuts cross existing welds.

10.3.4.2 Roof supporting structures shall be dismantled by removing bolts (if bolted) or deseaming the structural attachment welds.

10.3.5 Piece Marking

10.3.5.1 Shell, bottom, and roof plates shall be marked prior to dismantling for ready identification and placement when the tank is reconstructed. Marking material shall be of a durable type. Drawings showing piece mark locations are also a useful adjunct.

10.3.5.2 A minimum of two sets of matching center punch marks shall be located on the top and bottom edges of each shell plate to facilitate proper alignment during reconstruction.

10.4 Reconstruction

10.4.1 General

10.4.1.1 The foundation for the reconstructed tank shall meet the construction tolerances given in 10.5.6.

10.4.1.2 Temporary attachments shall be removed, and the attachment area ground flush with the plate surface.

10.4.2 Welding

10.4.2.1 Provisions shall be made during the reconstruction of a tank to ensure that weld spacing requirements of Figure 9.1 are maintained. New vertical joints in adjacent shell courses shall not be aligned but shall be offset from each other a minimum distance of $5t$, where t is the plate thickness of the thicker shell course at the point of the offset. New welds shall not be made in contact with the heat affected zone (HAZ) of existing shell welds, except as permitted under the provisions of 10.3.3.1.

10.4.2.2 Tanks and their structural attachments shall be welded in accordance with the processes specified in API 650, Section 5.8 and the requirements of 10.4.2.3 through 10.4.2.11.

10.4.2.3 No welding of any kind shall be performed when the surfaces of the parts to be welded are wet from rain, snow, or ice; when rain or snow is falling on such surfaces; or during periods of high winds unless the welder and the work are properly shielded. No welding of any kind shall be performed when the temperature of the base metal is less than –18 °C (0 °F). When the temperature of the base metal is between –18 °C (0 °F) and 0 °C (32 °F) or the thickness is in excess of 25 mm (1 in.), the base metal within 75 mm (3 in.) of the place where welding is to be started shall be heated to a temperature warm to the hand before welding. (See 10.4.4.3 for preheat requirements for shell plates over 38 mm [1 1/2 in.] thick.)

10.4.2.4 Each layer of weld metal of multilayer welding shall be cleaned of slag and other deposits before the next layer is applied.

10.4.2.5 The edges of all welds shall merge with the surface of the plate without a sharp angle. Maximum permissible weld undercut shall be in accordance with API 650, Section 7.2.1.5 and API 650, Section 8.5.2b).

10.4.2.6 The reinforcement of the new welds on all butt joints on each side of the plate shall not exceed the thicknesses shown in Table 10.1.

Table 10.1a—Maximum Thicknesses on New Welds, in SI Units

Plate Thickness (mm)	Maximum Reinforcement Thickness (mm)	
	Vertical Joints	Horizontal Joints
≤ 13	2.5	3
> 13 and ≤ 25	3	5
> 25	5	6

Table 10.1b—Maximum Thicknesses on New Welds, in USC Units

Plate Thickness (in.)	Maximum Reinforcement Thickness (in.)	
	Vertical Joints	Horizontal Joints
≤ 1/2	3/32	1/8
> 1/2 and ≤ 1	1/8	3/16
> 1	3/16	1/4

10.4.2.7 Tack welds used in the assembly of vertical joints of tank shells shall be removed and shall not remain in the finished joint when the joints are welded manually. When such joints are welded by the submerged-arc process, the tack welds shall be thoroughly cleaned of all welding slag but need not be removed provided that they are sound and are thoroughly fused into the subsequently applied weld beads. Tack welds shall be made using a fillet-weld or butt-weld procedure qualified in accordance with Section IX of the ASME Code. Tack welds to be left in place shall be made by qualified welders.

10.4.2.8 All foreign matter and coatings shall be removed as required to permit welds to be made that meet the quality requirements of this standard. If weldable primer coatings have been applied on surfaces to be welded, they shall be included in welding procedure qualification tests for the brand, formulation, and maximum thickness of primer applied.

10.4.2.9 Low-hydrogen electrodes shall be used for manual metal-arc welds, including the attachment of the first shell course to the bottom plates or annular plate ring, as follows:

a) for all welds in shell courses over 13 mm ($^1/_2$ in.) thick of API 650 Group I – III materials;

b) for all welds in all shell courses of API 650 Group IV – VI materials.

c) for all welds in all shell courses for which the API Group for the material cannot be reasonably ascertained in Section 11.1.2.

10.4.2.10 Low-hydrogen electrodes shall be used for welding temporary and new permanent attachments to shells of API 650 Group IV, IVA, V, or VI materials, or when the API Group for the material cannot be reasonably ascertained in Section 11.1.2. The welding procedure selected shall not cause underbead cracking; also, the need for preheat of thick plates and the effect of low ambient temperature during welding shall be considered.

10.4.2.11 If existing welds are found to be unsatisfactory by the as-built standard, they shall be repaired in accordance with 9.7.

10.4.3 Bottoms

10.4.3.1 After the bottom plates are laid out and tacked, they shall be joined by welding the joints in a sequence that results in the least distortion from shrinkage and provides, as nearly as possible, a plane surface.

10.4.3.2 The welding of the shell to the bottom (except for door sheets) shall be completed prior to the welding of bottom joints.

10.4.3.3 Plates shall be held in close contact at all lap joints during welding.

10.4.4 Shells

10.4.4.1 Plates to be joined by butt-welding shall be matched accurately and retained in position during welding. Misalignment in completed vertical joints over 16 mm ($^5/_8$ in.) thick shall not exceed 10 % of the plate thickness, with a maximum of 3 mm ($^1/_8$ in.). Misalignment in joints 16 mm ($^5/_8$ in.) thick or less shall not exceed 1.6 mm ($^1/_{16}$ in.) Vertical joints shall be completed before the lower horizontal weld is made.

10.4.4.2 In completed horizontal butt joints, the upper plate shall not project beyond the face of the lower plate at any point by more than 20 % of the thickness of the upper plate, with a maximum projection of 3 mm ($^1/_8$ in.), except that a projection of 1.6 mm ($^1/_{16}$ in.) is acceptable for upper plates less than 8 mm ($^5/_{16}$ in.) thick.

10.4.4.3 For horizontal and vertical joints in tank shell courses constructed of material over 40 mm (1 $^1/_2$ in.) thick (based on the thickness of the thicker plate at the joint), multi-pass weld procedures are required, with no pass more than 10 mm ($^3/_4$ in.) thick permitted. A minimum preheat of 90 °C (200 °F) is required of these welds.

10.4.5 Roofs

This standard does not include special stipulations for reconstruction thereof, except that the structural framing (such as rafters and girders) must be reasonably true to line and surface. Other requirements shall be in accordance with the as-built standard.

10.5 Dimensional Tolerances

10.5.1 General

10.5.1.1 The tolerances given in this section have been established to produce a reconstructed tank of acceptable appearance and structural integrity and to permit proper functioning of floating roofs and seals.

10.5.1.2 Measurements to verify these tolerances shall be taken before the hydrostatic test of the reconstructed tank.

10.5.2 Plumbness

10.5.2.1 The maximum out-of-plumbness of the top of the shell relative to the bottom of the shell shall not exceed $^{1}/_{100}$ of the total tank height, with a maximum of 125 mm (5 in.). The $^{1}/_{100}$ criteria, with a maximum of 125 mm (5 in.), shall also apply to fixed roof columns. For tanks with internal floating roofs, apply the criteria of this section or API 650, Section 7.5.2, and API 650, Section H.4.1.1, whichever is more stringent.

10.5.2.2 The out-of-plumbness in one shell course shall not exceed the values specified for mill tolerances in ASTM A6 or ASTM A20, whichever is applicable.

10.5.3 Roundness

Radii measured at 300 mm (1 ft) above the shell-to-bottom weld shall not exceed the tolerances shown in Table 10.2.

Radius tolerances measured higher than one foot above the shell-to-bottom weld shall not exceed three times the tolerances given in Table 10.2.

Table 10.2a—Radii Tolerances, in SI Units

Tank Diameter (m)	Radius Tolerances (mm)
< 12	±13
12 to < 45	±19
45 to < 75	±25
≥ 75	±32

Table 10.2b—Radii Tolerances, in USC Units

Tank Diameter (ft)	Radius Tolerances (in.)
< 40	$\pm^{1}/_{2}$
40 to < 150	$\pm^{3}/_{4}$
150 to < 250	±1
≥ 250	$\pm 1\ ^{1}/_{4}$

10.5.4 Peaking

With a horizontal sweep board 900 mm (36 in.) long, peaking shall not exceed 13 mm ($^1/_2$ in.). The sweep board shall be made to the true outside radius of the tank.

10.5.5 Banding

With a vertical sweep board 900 mm (36 in.) long, banding shall not exceed 25 mm (1 in.).

10.5.6 Foundations

10.5.6.1 To achieve the tolerances specified in 10.5.1 through 10.5.5, it is essential that foundations true to a plane be provided for the tank reconstruction. The foundation shall have adequate bearing capacity to maintain the trueness of the foundation.

10.5.6.2 Where foundations true to a horizontal plane are specified, tolerances shall be as follows:

a) where concrete ringwalls are provided under the shell, the top of the ringwall shall be level within ±3 mm ($^1/_8$ in.) in any 9 m (30 ft) of the circumference and within ±6 mm ($^1/_4$ in.) in the total circumference measured from the average elevation;

b) where concrete ringwalls are not provided, the foundation under the shell shall be level within ±3 mm ($^1/_8$ in.) in any 3 m (10 ft) of circumference and within ±13 mm ($^1/_2$ in.) in the total circumference measured from the average elevation.

10.5.6.3 For foundations specified to be sloped from a horizontal plan, elevation differences about the circumference shall be calculated from the specified high point. Actual elevation differences about the circumference shall be determined from the actual elevation of the specified high point. The actual elevation differences shall not deviate from the calculated differences by more than the following tolerances:

a) where concrete ringwalls are provided ±3 mm ($^1/_8$ in.) in any 9 m (30 ft) of circumference and ±6 mm ($^1/_4$ inches in the total circumference;

b) where concrete ringwalls are not provided, ±3 mm ($^1/_8$ in.) in any 3 m (10 ft) of circumference and ±13 mm ($^1/_2$ in.) in the total circumference.

SECTION 11—WELDING

11.1 Welding Qualifications

11.1.1 Welding procedure specifications (WPSs) and welders and welding operators shall be qualified in accordance with Section IX of the ASME Code, the additional requirements of API 650, Section 9, and this standard. Welding procedures for ladder and platform assemblies, handrails, stairways, and other miscellaneous assemblies, but not their attachments to the tank, shall comply with either AWS D1.1, AWS D1.6, or Section IX of the ASME Code, including the use of SWPSs.

11.1.2 Confirmation of Weldability of Steel from Existing Tanks

11.1.2.1 Weldability of steel from existing tanks shall be verified. If the material specification for the steel from an existing tank is unknown, a test coupon for the welding procedure qualification shall be taken from an actual existing plate, against which the new steel is to be welded. The coupon shall be tested to determine chemical composition and mechanical properties. Removal of a test coupon is not required, provided that the proposed welding procedure and proposed plan for nondestructive examination is reviewed and approved by a storage tank engineer.

11.1.2.2 If more than one area is to be repaired, and a decision has been made to remove a test coupon, a storage tank engineer shall determine if additional test coupons need to be removed. In lieu of removing additional test coupons, Optical Emission Spectroscopy (OES), a method for trace metal analysis, may be used to compare the composition of the steel on one or more of the other areas to be repaired against the results of the test coupon to provide enough confidence that the repair will be acceptable. When OES testing is done on multiple plates, a storage tank engineer shall review the results and again determine if additional test coupons need to be removed.

11.2 Identification and Records

11.2.1 The contractor shall assign each welder and welding operator an identifying number, letter, or symbol. Records of this identification, along with the date and results of the welder's qualification tests shall be accessible to the inspector or the owner/operator.

11.2.2 The welder or welding operator's identification mark shall be stamped, either by hand or machine, on all tanks. The mark shall be adjacent to and at intervals of not more than 1 m (3 ft) along the following welds: liquid-containing welds, including all opening welds and all opening reinforcements. Flange-to-nozzle-neck welds do not require welder identification. In lieu of stamping, the contractor may keep a written record that identifies the welder or welding operator employed for these welded joints. The written and/or stamped records shall be kept and maintained by the contractor until they are accepted by the inspector or the owner/operator, and they shall be submitted to the owner/operator for the repair and alteration history records of the tank.

11.3 Preheat or Controlled Deposition Welding Methods as Alternatives to Post-weld Heat Treatment (PWHT)

Preheat and controlled deposition welding, as described in 11.3.1 and 11.3.2, may be used in lieu of PWHT for repairs to existing nozzles where PWHT is required by API 653 or was performed in the original construction but is inadvisable or mechanically unnecessary for the repair. Prior to using any alternative method, a metallurgical review conducted by a storage tank engineer shall be performed to assess whether the proposed alternative is suitable for the application. The review shall consider the reason for the original PWHT of the equipment, susceptibility of the service to promote stress corrosion cracking, stresses in or near the weld, etc.

If materials are of unknown toughness and fall under the Figure 5.2 exemption curve, follow the requirements of 11.3.2. The storage tank engineer must concur in writing with the PWHT exemption. Also, the tank owner/operator must authorize the exemption in writing.

Selection of the welding method used shall be based on technical consideration of the adequacy of the weld in the as-welded condition at operating and hydrotest conditions.

11.3.1 Preheating Method (Impact Testing Not Required)

If impact testing is not required, the following additional preheat requirements apply.

a) This method is limited to use on P-1 materials that were not required to be impact tested as part of the original construction or under current requirements of API 650, Section 9.2.

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

c) The welders and welding procedures shall be qualified in accordance with the applicable rules of the original code of construction, except that the PWHT of the test coupon used to qualify the procedure shall be omitted.

d) The weld area shall be preheated and maintained at a minimum temperature of 150 °C (300 °F) during welding. The 150 °C (300 °F) 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 groove is maintained at the minimum temperature during welding. The maximum inter-pass temperature shall not exceed 315 °C (600 °F). When the weld does not penetrate through the full thickness of the material, the minimum preheat and maximum inter-pass 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.

11.3.2 Controlled-deposition Welding Method (Impact Testing Required)

If impact testing is required, the following welding requirements apply.

a) This method may be used when welding is to be performed on materials that were required to be impact tested per 4.2.9 and 4.2.10 of API 650 as part of the original construction or under current requirements of API 650, Section 9.2, and is limited to P-1, P-3, and P-4 steels.

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

c) A weld procedure specification shall be developed and qualified for each application. The welding procedure shall define the preheat temperature, the inter-pass temperature and the post heating temperature requirement in Item e), 8) below. The qualification thickness for the test plates and repair grooves shall be in accordance with Table 11.1.

Table 11.1—Welding Methods as Alternatives to Post-weld Heat Treatment (PWHT) Qualification Thicknesses for Test Plates and Repair Grooves

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.)	$\leq T$
t	$< t$	≥ 50 mm (2 in.)	50 mm (2 in.) to unlimited

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

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 %.

d) 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 are adequate at the minimum design metal temperature. If special hardness limits are necessary for corrosion resistance (e.g. those set forth in NACE RP 0472, NACE MR 0103 and NACE MR 0175), the PQR shall include hardness test results.

e) The WPS shall include the following additional requirements.

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

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 inter-pass 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, from the edge of each weld.

6) For the welding processes in 11.3.2 b), use only electrodes and filler metals that are classified by the filler metal specification with an optional supplemental diffusible-hydrogen designator of H8 or lower. When shielding gases are used with this process, the gas shall exhibit a dew point that is no higher than –50 °C (–60 °F). Surfaces on which welding is to performed shall be maintained in a dry condition during the welding and free of rust, mill scale and hydrogen-producing contaminants such as oil, grease and other organic materials.

7) The welding technique shall be a controlled-deposition, 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 to four hours to assist out-gassing diffusion of any weld-metal hydrogen picked up during welding. This hydrogen bake-out 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 to ambient temperature, the final temper bead reinforcement layer shall be removed substantially flush with the surface of the base material.

11.4 Welding Safety

Welding shall conform to the permit and safety precautions of 1.4. Permits shall consider tank conditions in the hot-work areas which might release flammable vapors (such as perforation resulting from corrosion).

11.5 Friction Stud Welding

Rotary friction welding may be used to install studs on in-service and out-of-service tanks including, but not limited to tank shells, roofs, and floating roofs by agreement between the repair organization and the tank owner/operator.

Welding procedure specifications (WPSs) and welding operators shall be qualified in accordance with Section IX of the ASME Code, and both shall be certified. A WPS shall be created by the repair organization for each material P-No. in ASME Section IX. If the stud material is different than the base material, then a WPS shall be created for each material P-No. combination. Impact testing is not required for procedure qualification record (PQR) testing.

The work shall be performed in accordance with the requirements of API 650 Section 9 and the following requirements:

a) The design of retrofits and repairs attached with friction welded studs shall be approved by a storage tank engineer. The design shall consider all anticipated loading conditions and combinations, potential settlement movements, high strains and rotations at structural discontinuities such as the shell-to-bottom joint and shell penetrations, inability of bolted joints to share load with welds due to lesser stiffness, limited ability of bolted joints to carry shell hoop stress, gasket sealing forces, minimum/maximum design temperatures, design metal temperature, friction stud and base metal toughness, material compatibility, internal and external coatings, and life span requirements.

b) Installations on in-service tanks shall address risks related to the safety of workers and ignition of flammable tank contents, specifically addressed in 1.4 of this standard. The repair organization shall demonstrate ignition safety by testing and submitting a written report to the tank owner/operator. The tank owner/operator and repair organization shall agree on the safety criteria and protocols to be used to demonstrate that the potential ignition safety issues have been addressed, providing that the side of the tank opposite to the friction stud welding does not create an ignition source.

NOTE See “Forge Bonding: A Safer Metal Joining Process,” D. Rybicki, M. Rybicki, Proceedings of the AIChE 2016 Spring Meeting and Global Congress on Process Safety, April, 2016.

c) Areas to be friction welded shall be ultrasonically examined for remaining substrate thickness. A stud shall not be friction welded to a tank with less than 4 mm (0.15 in.) of remaining metal thickness without special consideration for ignition safety, stud strength, and quality of the remaining metal.

d) Preheating and PWHT are not required.

SECTION 12—EXAMINATION AND TESTING

12.1 NDE

12.1.1 General

12.1.1.1 NDE shall be performed in accordance with API 650, Section 8, and any supplemental requirements given herein.

12.1.1.2 Personnel performing NDE shall be qualified in accordance with API 650, Section 8, and any supplemental requirements given herein.

12.1.1.3 Acceptance criteria shall be in accordance with API 650, Section 8, and any supplemental requirements given herein.

12.1.1.4 Examiners performing ultrasonic thickness measurements shall be qualified in accordance with an approved procedure and shall be certified to ASNT UT Level II full or limited certification for either digital thickness measurement (numeric output only) or A-scan thickness measurement according to ASNT-SNT-TC-1A or an equivalent national standard recognized by the owner/operator. Trainee personnel may be used if they are under direct supervision of Level II or Level III UT certified personnel.

12.1.1.5 Each newly deposited weld or any cavity resulting from gouging or grinding operations shall be visually examined over its full length. Additional NDE of these welds may be required as described in the following relevant sections.

12.1.1.6 Annex G may be used to provide additional guidance in qualifying personnel and procedures when magnetic flux leakage (MFL) tools are used to examine tank bottoms. Owner/operators should determine specific requirements to meet their tank bottom integrity needs.

12.1.1.7 Ultrasonic examination in accordance with API 650, Annex U, may be alternatively applied by agreement between the Purchaser and Manufacturer when the radiographic method is specified for examination of welds.

12.1.2 Shell Penetrations

12.1.2.1 Ultrasonic examination of shell plate for laminations shall be made in the immediate area affected when:

a) adding a reinforcing plate to an existing unreinforced penetration,

b) adding a hot tap connection.

12.1.2.2 Cavities resulting from gouging or grinding operations to remove attachment welds of existing reinforcing plates shall be examined by magnetic particle or liquid penetrant methods.

12.1.2.3 Completed welds attaching nozzle neck to shell, and reinforcing plate to shell and to nozzle neck, shall be examined by the magnetic particle or liquid penetrant methods. Consider additional examination (e.g. fluorescent magnetic particle examination and/or ultrasonic examination) for hot tap connections to shell plates of unknown toughness (defined in Section 3).

12.1.2.4 Completed welds of stress-relieved assemblies shall be examined by the magnetic particle or liquid penetrant methods after stress relief, but before hydrostatic testing.

12.1.3 Examination of Repaired Weld Defects

12.1.3.1 Cavities resulting from gouging or grinding operations to remove weld defects shall be examined by the magnetic particle or liquid penetrant methods.

12.1.3.2 Completed weld repairs of butt welds shall be examined over their full length by radiographic or ultrasonic methods. However, for completed repairs to butt welds found in shell plate to shell plate joints, the additional radiographs, as required in 12.2.1.1.c), 12.2.1.2.c), and 12.2.1.3.c), do not apply.

12.1.3.3 Completed weld repairs of fillet welds shall be examined over their full length by the appropriate NDE method listed herein.

12.1.4 Temporary and Permanent Attachments to Shell Plates

12.1.4.1 The welds of permanent attachments (not including shell-to-bottom welds) and areas where temporary attachments are removed and the remaining weld projections have been removed shall be examined visually.

12.1.4.2 The requirements of this section shall be followed when welding to API 650 Group IV, IVA, V, and VI materials, or when the API Group for the material cannot be reasonably ascertained in Section 11.1.2. Completed welds of new permanent attachments (not including shell-to-bottom welds) and areas where temporary attachments have been removed shall be examined by the magnetic particle method (or, at the option of the Purchaser, by the liquid penetrant method).

12.1.5 Shell Plate to Shell Plate Welds

12.1.5.1 New full penetration welds attaching existing shell plate to existing or new shell plate shall be examined by radiographic methods (see 12.2). In addition, for plate thicknesses greater than 25 mm (1 in.), the back-gouged surface of the root pass and final pass (each side) shall be examined for its complete length by magnetic particle or liquid penetrant methods.

12.1.5.2 New welds joining new shell plate material to new shell plate material (partial or full shell course replacement or addition) need only be examined radiographically in accordance with API 650, Section 8.1.

12.1.6 Shell-to-bottom Weld

12.1.6.1 New welding on the shell-to-bottom joint shall be examined for its entire length by using a right-angle vacuum box and a solution film, or by applying light diesel oil. Additionally, the first weld pass shall be examined by applying light diesel oil to the side opposite the first weld pass made. The oil shall be allowed to stand at least 4 hours (preferably overnight) and then the weld examined for wicking action. The oil shall be removed before the weld is completed.

12.1.6.2 As an alternative to 12.1.6.1, the initial weld passes, inside and outside of the shell, shall have all slag and nonmetals removed from the surface of the welds and examined visually. Additionally, after completion of the inside and outside fillet or partial penetration welds, the welds shall be tested by pressurizing the volume between the inside and outside welds with air pressure to 100 kPa (15 psig) and applying a solution film to both welds. To assure that the air pressure reaches all parts of the welds, a sealed blockage in the annular passage between the inside and outside welds must be provided by welding at one or more points. Additionally, a small pipe coupling communicating with the volume between the welds must be welded on each side of and adjacent to the blockages. The air supply must be connected at one end and a pressure gauge connected to a coupling on the other end of the segment under test.

12.1.6.3 The existing weld at the shell-to-bottom joint shall be examined by visual, as well as by magnetic particle or liquid penetrant methods, for the full length under a welded-on patch plate. An additional 150 mm (6 in.) of the shell-to-bottom joint on each side of the welded-on patch plate shall be examined similarly before placement of the repair plate to assure weld integrity and to confirm the absence of weld cracks.

12.1.7 Bottoms

12.1.7.1 Upon completion of welding on a tank bottom, the plates and the entire length of new welds for tank bottom plates shall be examined visually for any potential defects and leaks. Particular attention shall apply to areas such as sumps, dents, gouges, three-plate laps, bottom plate breakdowns, arc strikes, temporary attachment removal areas, and welding lead arc burns. Visual examination acceptance and repair criteria are specified in API 650, Section 8.5. In addition, all new welds, including the weld attaching a patch plate to the bottom, the areas of bottom plate restored by welding, and the restoration of welds found with defects during an internal inspection shall be examined by one of the methods specified in API 650, Section 7.3.3. Leaking areas shall be repaired by grinding and rewelding as required, and the repaired area shall be retested.

12.1.7.2 In addition to the requirements in 12.1.7.1, the root and final pass of a welded-on patch plate weld in the critical zone (see 3.10 for definition) shall be visually examined and examined by either magnetic particle or liquid penetrant method over its full length.

12.1.7.3 In addition to the requirements in 12.1.7.1, areas of bottom plate repaired by welding shall be examined by the magnetic particle method or the liquid penetrant method. In addition, the repaired area shall also be tested using a vacuum box and solution or a tracer gas and detector.

12.1.8 Shell Plate

12.1.8.1 Shell Plate Repairs by Weld Metal Deposit

Areas of shell plate to be repaired by welding shall be examined visually. In addition, shell plate areas repaired by welding shall be examined by the magnetic particle method (or the liquid penetrant method).

12.1.8.2 Shell Plate Repairs by Lap-welded Patches

The attachment welds of new lap-welded shell patches shall be visually examined, and shall be examined by either the magnetic particle or liquid penetrant methods.

12.1.9 Fixed Roofs

Newly welded roof joints and repairs shall be examined in accordance with API 650, Section 7.3.2.2 and Section 7.3.8.

12.1.10 Floating Roofs

12.1.10.1 Repair Work to Steel Floating Roofs

After repair work is complete:

a) perform a visual examination from the top and bottom side of the floating roof;

b) perform an air leak, vacuum box, penetrating oil, tracer gas, or other applicable nondestructive test of the repaired welds (see Annex F).

As an alternative to Item b), conduct a flotation test of the repaired roof.

Examination and acceptance criteria for NDE shall be in accordance with 12.1.

12.1.11 Friction Stud Welds

Friction welded studs shall be visually examined and torque tested in accordance with ASME Section IX torque test requirements. The stress applied to the stud during the torque test shall not yield the stud material. The NDE of the friction welded studs shall apply for all tank and stud P-No. materials.

12.2 Radiographs

12.2.1 Number and Location of Radiographs

The number and location of radiographs of the full penetration shell plate to shell plate welds shall be in accordance with API 650, Section 8.1.2 and the following additional requirements:

12.2.1.1 For vertical joints:

a) new replacement shell plates to new shell plates, no additional radiographs required, other than those required by API 650, Section 8.1.2.2 and Figure 8.1 for new construction;

b) new replacement shell plates to existing shell plates, one additional radiograph shall be taken in each joint;

c) repaired joints in existing shell plates shall have one additional radiograph taken in each joint.

12.2.1.2 For horizontal joints:

a) new replacement shell plates to new shell plates, no additional radiographs required, other than those required by API 650 Section 8.1.2.3 and API 650 Figure 8.11 for new construction;

b) new replacement shell plates to existing shell plates, one additional radiograph for each 15 m (50 ft) of repaired horizontal weld;

c) repaired joints in existing shell plates shall have one additional radiograph taken for each 15 m (50 ft) of repaired horizontal weld.

12.2.1.3 For intersections of vertical and horizontal joints:

a) new replacement shell plates to new shell plates, no additional radiographs required, other than those required by API 650, Section 8.1.2 and Figure 8.1 for new construction;

b) new replacement shell plates to existing shell plates, each intersection shall be radiographed;

c) all repaired intersections in existing shell plates shall be radiographed.

12.2.1.4 For reconstructed tanks, each butt-welded annular plate joint shall be radiographed in accordance with API 650, Section 8.1.2.9.

12.2.1.5 For reconstructed tanks, radiographic examination is required for 25 % of all junctions of new welds over existing seams.

The owner/operator shall, with the consent of the contractor, determine the extent of further examination and repair that may be required.

Any further examination or repair of existing welds will be handled by contractual agreement between the owner/operator and tank reconstruction contractor.

12.2.1.6 New and replaced shell plate and door sheet welds shall be radiographed. All junctions between repair and existing welds shall be radiographed. If defects are found, 100 % radiography shall be performed on the repaired weld.

12.2.1.6.1 For circular replacement plates, a minimum of one radiograph shall be taken regardless of thickness. When the circular replacement plate is located in a shell plate with thickness exceeding 25 mm (1 in.), the weld shall be fully radiographed.

12.2.1.6.2 For square and rectangular replacement plates, at least one radiograph shall be taken in a vertical joint, and at least one in a horizontal joint, and one in each corner. When the square or rectangular replacement plate is located in a shell plate with thickness exceeding 25 mm (1 in.), the vertical joints shall be fully radiographed.

12.2.1.7 The minimum diagnostic length of each radiograph shall be 150 mm (6 in.).

12.2.1.8 For penetrations installed using insert plates or thickened insert plates as described in 9.9.6, the completed butt welds between the insert plate or thickened insert plate and the adjoining shell material shall be fully radiographed.

12.2.2 Acceptance Criteria for Existing Shell Plate to Shell Plate Welds

If the radiograph of an intersection between a new and old weld detects unacceptable welds by the current applicable standard, the existing welds shall be:

a) evaluated according to the as-built standard, or

b) evaluated using fitness-for-service assessment, or

c) repaired in accordance with 9.7.

12.2.3 Marking and Identification of Radiographs

12.2.3.1 Each film shall show an identification of the welder(s) making the weld. A weld map showing location of welds, weld number, radiograph number, welder identification, and grading of each weld is an acceptable alternative to this requirement.

12.2.3.2 Radiographs and radiograph records of all repaired welds shall be marked with the letter “R.”

12.3 Hydrostatic Testing

12.3.1 When Hydrostatic Testing is Required

A hydrostatic test shall be performed on the following.

a) A reconstructed tank.

b) Any tank that has undergone major repairs or major alterations (see Section 3) unless exempted by 12.3.3 for the applicable combination of materials, design, and construction features.

c) A tank where an engineering evaluation indicates the need for the hydrostatic test due to an increase in the severity of service. Examples of increased service severity are an increase in operating pressure (such as storing a product with a higher specific gravity), lowering the service temperature (see Figure 5.2), and using tanks that have been damaged.

12.3.2 Hydrostatic Test Procedure

The hydrostatic test procedure encompasses the following steps:

1) A tank with a hydrostatic test required by this standard shall be filled to the level stated in API 650, Section 7.3.6(1)(a), unless the level is limited by the tank condition as given in section 4.3.3.2 of this standard.

2) That liquid level shall be held for a minimum of 24 hours.

3) The tank shall be inspected frequently during the filling operation for indications of leaks and/or settlement. Any repaired weld joints above the liquid level shall be examined in accordance with API 650, Section 7.3.6(1)(b).

12.3.3 Hydrostatic Testing Exemptions (Major Repairs/Alterations)

12.3.3.1 General

A full hydrostatic test of the tank is not required for major repairs and major alterations if 12.3.3.2 is satisfied plus either of the following:

a) appropriate parts of 12.3.3.3 through 12.3.3.6, or

b) fitness-for-service evaluation per 12.3.3.7.

12.3.3.2 Review/Approval/Authorization Requirements

Items a) and b) below must be satisfied.

a) The repair has been reviewed and approved by an engineer experienced in storage tank design in accordance with API 650. The engineer must concur in writing with taking the hydrostatic testing exemption.

b) The tank owner/operator has authorized the exemption in writing.

12.3.3.3 Shell Repair

12.3.3.3.1 For welds to existing metal, develop welding procedure qualifications based on existing material chemistry, including strength requirements. Welding procedures shall be qualified with existing or similar materials, and shall include impact testing. Impact testing requirements shall follow appropriate portions of API 650, Section 9.2.2 and shall be specified in the repair procedure.

12.3.3.3.2 New materials used for the repair shall meet the current edition of API 650, Section 4, requirements.

12.3.3.3.3 Existing tank materials in the repair area shall meet at least one of the following requirements.

a) API 650 requirements (Seventh Edition or later).

b) Fall within the “safe for use” area on Figure 5.2.

c) Stress in the repair area shall not exceed 48 MPa (7000 lbf/in.^{2}). This limiting stress shall be calculated as follows:

In SI units: $S = \dfrac{4.9\ HDG}{t}$

where

S is the shell stress in megapascals (MPa);

H is the tank fill height above the bottom of repair or alteration in meters (m);

t is the shell thickness at area of interest in millimeters (mm);

D is the tank mean diameter in meters (m);

G is the specific gravity of product.

In USC units: $S = \dfrac{2.6\ HDG}{t}$

where

S is the shell stress in pound force per square inch (lbf/in.^{2});

H is the tank fill height above the bottom of repair or alteration in feet (ft);

t is the shell thickness at area of interest in inches (in.);

D is the tank mean diameter in feet (ft);

G is the specific gravity of product.

12.3.3.3.4 New vertical and horizontal shell butt welds shall have complete penetration and fusion.

12.3.3.3.5 The root pass and final pass examination shall be in accordance with 12.1.5. In addition, the finished weld shall be fully radiographed.

12.3.3.3.6 Shell welds for the reinforcing plate-to-nozzle neck and nozzle neck-to-shell joints shall have complete penetration and fusion. The root pass of the nozzle attachment weld shall be back-gouged and examined by magnetic particle or liquid penetrant methods. Completed welds shall be examined by magnetic particle or liquid penetrant methods. Additionally, completed welds shall be examined by the ultrasonic method. Examination and acceptance criteria for NDE shall be in accordance with 12.1.

12.3.3.3.7 See 12.3.3.5 for shell-to-bottom weld restrictions.

12.3.3.3.8 Door sheets shall comply with the requirements of this standard for shell plate installation, except they shall not extend to or intersect the bottom-to-shell joint.

12.3.3.4 Bottom Repair within the Critical Zone

Repairs to the annular ring or bottom plates, within the critical zone (defined in Section 3) shall comply with the following.

a) Meet the requirements of 12.3.3.3.1 through 12.3.3.3.3.

b) Be examined visually prior to welding, and examined after the root pass and the final pass by the magnetic particle or liquid penetrant methods. Annular plate butt welds shall also be examined by ultrasonic methods after the final pass. Examination and acceptance criteria for NDE shall be in accordance with 12.1.

12.3.3.5 Shell-to-bottom Weld Repair

12.3.3.5.1 Repair of the weld attaching the shell to the annular ring or the shell to the bottom plate shall meet one of the following requirements.

a) A portion of the weld (of any length) may be removed and replaced as long as the replaced weld meets the size requirements of API 650, Section 5.1.5.7, and the portion replaced does not represent more than 50 % of the required weld cross-sectional area.

b) The weld on one side of the shell may be completely removed and replaced for a length not exceeding 300 mm (12 in.). Shell-to-bottom weld repairs replacing more than 50 % of the required weld cross-sectional area shall not be closer than 300 mm (12 in.) to each other, including repairs on the opposite side of the shell.

c) For a tank that is 9 m (30 ft) in diameter or less and falls within the "safe for use" area on Figure 5.2, the welds on both sides of the shell-to-bottom joint may be either completely removed and replaced or may be deposited anew in the case of a bottom replacement meeting 9.11.2 requirements.

12.3.3.5.2 Repairs shall be examined prior to welding, after the root pass, and after the final pass by visual, as well as magnetic particle or liquid penetrant methods. Examination and acceptance criteria for NDE shall be in accordance with 12.1.

12.3.3.6 Minor Shell Jacking

12.3.3.6.1 Tank shell and critical zone materials shall meet one of the requirements of 12.3.3.3.3.

12.3.3.6.2 The engineer shall consider all pertinent variables when exempting a minor shell jacking repair from hydrostatic testing, including but not limited to: the magnitude of jacking required; material; toughness; quality control; inspection before and after repair; material temperature; future foundation stability; and jacking techniques (including controls and measurement). Careful consideration shall be given to potential stresses and damage that may result from jacking.

12.3.3.7 Fitness-for-Service Evaluation

The owner/operator may utilize a fitness-for-service or other appropriate evaluation methodology based on established principles and practices to exempt a repair from hydrostatic testing. The procedures and acceptance criteria for conducting an alternative analysis are not included in this standard. This evaluation shall be performed by an engineer experienced in storage tank design and the evaluation methodologies used.

12.3.4 Hydrostatic Testing Exemptions (Other)

12.3.4.1 General

For clarity, the situations of 12.3.4.2 and 12.3.4.3 do not in themselves require a hydrostatic test because they are not major repairs or major alterations.

12.3.4.2 Repair or Alteration Made to a Floating Roof

No hydrotest is required.

12.3.4.3 Bottom Repair or Replacement Outside the Critical Zone

Portions of new bottoms (any or all rectangular plates or large segments of plates) in tanks may be replaced without a hydrotest when the subgrade under the new plates is found to be in a condition acceptable to the authorized inspector or is restored to such condition and either of the following conditions is met.

1) For tanks with annular rings, the annular ring and the area of support under the annular ring (concrete foundation or grade material) remains intact.

2) For tanks without annular rings, the bottom repair or replacement does not result in welding on the remaining bottom within the critical zone and the shell and bottom support in the critical zone (defined in Section 3) remains intact.

12.4 Leak Tests

New or altered reinforcing plates of shell penetrations shall be given an air leak test in accordance with API 650, Section 7.3.5.

12.5 Settlement Survey During Hydrostatic Testing

12.5.1 When Settlement Survey is Required

A settlement survey shall be conducted for all existing tanks that undergo a hydrostatic test, except for tanks that have a documented service history of acceptable settlement values, **and** no settlement is anticipated to occur during the hydrotest.

12.5.2 Initial Settlement Survey

When a settlement survey is required in accordance with 12.5.1, the tank settlement shall initially be surveyed with the tank empty, using an even number of elevation measurement points, N, uniformly distributed around the circumference. An initial settlement survey, prior to the first hydrostatic test, provides baseline readings for future settlement evaluation. In the absence of this initial survey, the tank shall be assumed to be initially level.

The minimum number of elevation points shall be as indicated by the following equation:

$$N = D/10$$

where

D is the tank diameter, in feet (ft).

And

N is the minimum required number of settlement measurement points, but no less than eight. All values of N shall be rounded to the next higher even whole number. The maximum spacing between settlement measurement points shall be 10 m (32 ft).

12.5.3 Settlement Survey During Hydrostatic Testing

When a settlement survey is required in accordance with 12.5.1, tank settlement shall be measured during filling and when the test water reaches 100 % of the test level.

SECTION 13—MARKING AND RECORDKEEPING

13.1 Nameplates

13.1.1 Reconstructed Tanks

13.1.1.1 Tanks reconstructed in accordance with this standard shall be identified by a corrosion-resistant metal nameplate similar to that shown in Figure 13.1. Letters and numerals not less than 4 mm ($^{5}/_{32}$ in.) high shall be embossed, engraved, or stamped in the plate to indicate information as follows:

a) reconstructed to API 653;

b) edition and revision number;

c) year reconstruction was completed;

d) if known, the as-built standard and the year of original construction;

e) nominal diameter;

f) nominal shell height;

g) design specific gravity;

h) maximum permissible operating liquid level;

i) the name of the reconstruction contractor and the assigned serial number or contract number;

j) the owner/operator's tank number;

k) shell material for each shell course;

RECONSTRUCTED TO API 653 EDITION ____________________

Reconstructed by:			
____________________			Original Standard ______
____________________			Tank No. ______
Date Completed ______			Tank Diam. ______ Height ______
Serial No. ______			Specific Gravity ______
			Design Pressure ______
Shell Course	Allowable Stress	Material	Orig. Const. Date ______
______	______	______	Year Reconstructed ______
______	______	______	Liquid Level Max. ______
______	______	______	Capacity ______
______	______	______	Max. Operating Temp. ______

Figure 13.1—Nameplate

l) maximum operating temperature;

m) allowable stress used in calculations of each shell course.

13.1.1.2 The new nameplate shall be attached to the tank shell adjacent to the existing nameplate, if any. An existing nameplate shall be left attached to the tank. Nameplates shall be attached as specified in API 650, Section 10.1 and Figure 10.1.

13.1.2 Tanks Without Nameplates

13.1.2.1 At the owner's request a nameplate may be attached to a tank meeting the requirements in 13.1.2.2 through 13.1.2.4.

13.1.2.2 If information required to complete the nameplate as required by the as-built standard is available and traceable to the tank, a new replacement nameplate, similar to that shown in Figure 10.1 in API 650, may be attached under the direction of the authorized inspector. The new nameplate shall contain all of the information required by the as-built standard and be marked "Replacement Nameplate."

13.1.2.3 If information required to complete the nameplate as required by the as-built standard is not available, an 'Assessment Nameplate' may be attached under the direction of the authorized inspector, provided a suitability for service assessment is performed per Sections 4 and 5. The new nameplate shall contain the following information:

a) API Standard 653, *Assessment Nameplate*;

b) owner's tank number;

c) the company performing the assessment;

d) the date the assessment was performed;

e) the date of the edition and the addendum number of API 653 used to perform the assessment;

f) the nominal diameter and nominal height, in meters (ft and in.);

g) the maximum capacity in m^3 (42-gallon barrels);

h) the liquid level in meters (ft. and in.) used to perform the assessment;

i) the specific gravity of the liquid used to perform the assessment;

j) the design metal temperature in °C (°F) used to perform the assessment;

k) the pressure and vacuum used to perform the assessment;

l) the maximum design temperature in °C (°F) used to perform the assessment;

m) the material specification, if known, for each shell course;

n) the allowable stress values in MPa (psi) used to perform the assessment;

o) the joint efficiency used to perform the assessment (see 4.3.3. or 4.3.4).

13.1.2.4 The nameplate shall be made of a corrosion resistant metal embossed, engraved, or stamped with letters and numerals not less than 4 mm ($^5/_{32}$ in.) high. Nameplates shall be attached as specified in API 650. In addition, the nameplate shall be clearly marked as an API 653, *Assessment Nameplate*. Refer to Figure 13.2.

13.2 Recordkeeping

When a tank is evaluated, repaired, altered, or reconstructed in accordance with this standard, the following information, as applicable, shall be made a part of the owner/operator's records for the tank (see 6.8).

13.2.1 Calculations for:

a) component evaluation for integrity, including brittle fracture considerations (see Section 5);

b) re-rating (including liquid level);

c) repair and alteration considerations.

13.2.2 Construction and repair drawings.

13.2.3 Additional support data including, but not limited to, information pertaining to:

a) examinations (including thicknesses);

b) material test reports/certifications;

c) tests;

d) radiographs (radiographs shall be retained for at least one year);

e) brittle fracture considerations;

f) original tank construction data (date, as-built standard, etc.);

g) location and identification (owner/operator's number, serial number);

h) description of the tank (diameter, height, service);

i) design conditions (liquid level, specific gravity, allowable stress, unusual design loadings, etc.);

j) shell material and thickness by course;

k) tank perimeter elevations;

l) construction completion record;

m) basis for hydrostatic test exemption.

13.3 Certification

Tanks reconstructed in accordance with this standard shall require documentation of such reconstruction, and certification that the design, reconstruction, inspection, and testing was performed in compliance with this standard. The certification shall contain information as shown in Figure 13.2 for design and/or reconstruction as applicable.

CERTIFICATION FOR TANK RECONSTRUCTED TO API 653

We hereby certify that the tank reconstructed at ____ and described as follows:

Location

Serial No.	Owner's No.	Height	Capacity	Floating or Fixed Roof

was reconstructed, inspected, and tested in accordance with all applicable requirements of API Standard 653,

________________ Edition, ________________ Revision, Dated ________________ (including all material supplied by the reconstruction organization).

Reconstruction Organization

Authorized Representative

Date

CERTIFICATION FOR TANK DESIGNED TO API 653

We hereby certify that the design evaluation of the tank reconstructed at ____ and described as follows:

Location

Serial No.	Owner's No.	Height	Capacity	Floating or Fixed Roof

was performed by the undersigned organization in accordance with all design requirements of API Standard 653,

________________ Edition, ________________ Revision, Dated ________________.

Reconstruction Organization

Authorized Representative

Date

Figure 13.2—Certification Forms

Annex A
(informative)

Background on Past Editions of API Welded Storage Tank Standards

API published a specification for welded steel storage tanks in 1936 entitled API Standard 12C, *All-Welded Oil Storage Tanks*. Fifteen editions and seven supplements to API 12C were published between 1936 and 1958. API 12C was replaced by API Standard 650, *Welded Tanks for Oil Storage*; 12 editions and 23 supplements, revisions or addenda to API 650 have been issued. The current edition of API 650 is the 12th Edition, Addendum 2, published in January 2016.

The table below provides a list of editions, supplements, and revisions to API 12C and API 650.

Table A.1—Editions of API Standard 650 and its Precursor, API Standard 12C

API Standard 12C, *All-Welded Oil Storage Tanks*			API Standard 650, *Welded Tanks for Oil Storage*	
Edition	**Date**		**Edition**	**Date**
First	July 1936		First	December 1961
Second	October 1937		Supplement	1963
Supplement 1	April 1938		Second	April 1964
Supplement 2	September 1938		Third	July 1966
Supplement 3	April 1939		Supplement 1	December 1967
Third	April 1940		Fourth	June 1970
Fourth	March 1941		Supplement 1	April 1971
Fifth	May 1942		Fifth	July 1973
Sixth	August 1944		Supplement 1	October 1973
Seventh	August 1946		Supplement 2	April 1974
Supplement 1	September 1947		Supplement 3	March 1975
Eighth	September 1948		Sixth	April 1977
Supplement 1	December 1949		Revision 1	May 1978
Ninth	October 1950		Revision 2	December 1978
Tenth	September 1951		Revision 3	October 1979
Eleventh	September 1952		Seventh	November 1980
Supplement 1	September 1953		Revision 1	February 1984
Twelfth	October 1954		Eighth	November 1988
Thirteenth	September 1955		Ninth	July 1993
Supplement 1	October 1956		Addendum 1	December 1994
Fourteenth	October 1957		Addendum 2	December 1995
Fifteenth	1958		Addendum 3	December 1996
			Addendum 4	December 1997

Table A.1—Editions of API Standard 650 and its Precursor, API Standard 12C (Continued)

API Standard 12C, *All-Welded Oil Storage Tanks*			API Standard 650, *Welded Tanks for Oil Storage*	
Edition	**Date**		**Edition**	**Date**
			Tenth	November 1998
			Addendum 1	March 2000
			Addendum 2	November 2001
			Addendum 3	August 2003
			Addendum 4	December 2005
			Errata	April 2007
			Eleventh	June 2007
			Addendum 1	November 2008
			Addendum 2	November 2009
			Addendum 3	August 2011
			Errata	October 2011
			Twelfth	March 2013
			Errata	July 2013
			Addendum 1	September 2014
			Addendum 2	January 2016
			Addendum 3	August 2018
			Thirteenth	March 2020

NOTE Ordering information for past editions of API 12C and API 650 is available by calling IHS Inc. at 1-800-854-7179 (www.global.ihs.com).

As of the date this edition (or addenda) of API 653 was published, the current edition of API 650 is the 13th Edition, published in March 2020. Please check with the API Publications Department, or see www.api.org for the latest API 650 release.

Annex B
(normative)

Evaluation of Tank Bottom Settlement

B.1 Introduction

B.1.1 In determining the effects of soil settlement on storage tanks, it is common practice to monitor settlement of the tank bottom. In most cases, such a monitoring program is initiated during the construction and continued during hydrostatic testing and operations. During operations, settlement measurements should be taken at a planned frequency, based on an assessment of soil settlement predictions. For existing tanks that do not have initial settlement data, a program of settlement monitoring should be based on prior service history.

B.1.2 If at any time settlement is deemed excessive, the tank should be emptied and re-leveled. Re-leveling of a sizable tank is expensive and rather difficult to achieve. Thus, a decision to re-level a tank is a crucial one, and relies very much on the proper interpretation and evaluation of the monitored settlement data.

B.1.3 Approaches used to correct tank shell and bottom settlement include techniques such as localized repairs of the bottom plates, partial re-leveling of the tank periphery, and major re-leveling of the entire tank bottom. Major re-leveling of the tank, involving total lifting of the tank shell and bottom at one time, can introduce highly localized stresses in the structure and impair its integrity. Therefore, when choosing techniques for correcting settlement problems, an alternative to total lifting of the tank shell and bottom should be considered as a first choice. If it is decided to lift the entire tank shell and bottom at one time, it should be done by personnel with demonstrated experience in this technique.

B.2 Types of Settlement

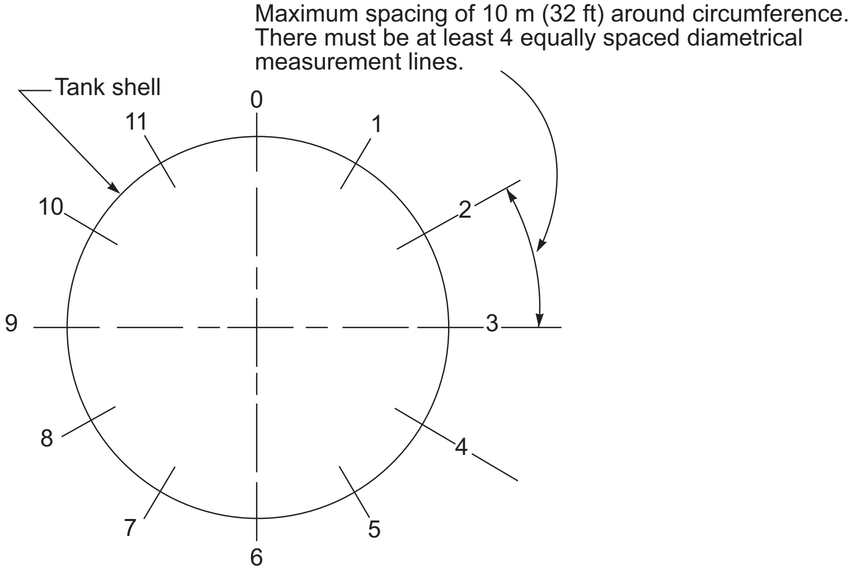
B.2.1 Settlement Measurements

Measurements of tank settlement should be performed by personnel experienced in the types of measurement procedures being performed, using equipment capable of sufficient accuracy to distinguish settlement differences.

The principle types of tank settlement consist of settlements that relate to the tank shell and bottom plate. These settlements can be recorded by taking elevation measurements around the tank circumference and across the tank diameter. Figure B.1 and Figure B.2 show minimum recommended locations on a tank shell and bottom plate for settlement measurements. Data obtained from such measurements should be used to evaluate the tank structure. Additional settlement readings may be required to better define local bottom depressions or edge settlements, to refine shell settlement measurements in areas suspected to have local out-of-plane settlements, or to otherwise improve bottom or shell settlement evaluation. Settlement measurement locations should be re-used in any future settlement surveys and evaluations.

In cases of distortion or corrosion of the tank bottom extending beyond the shell, shell settlement measurements taken near lap welds in the tank bottom can result in significant errors in measured elevation. Repaired or replaced bottom plates, or new slotted-in bottoms may not have been installed parallel to the original bottom. In some cases, more consistent and accurate results may be obtained by surveying the elevation of the weld between the first and second courses.

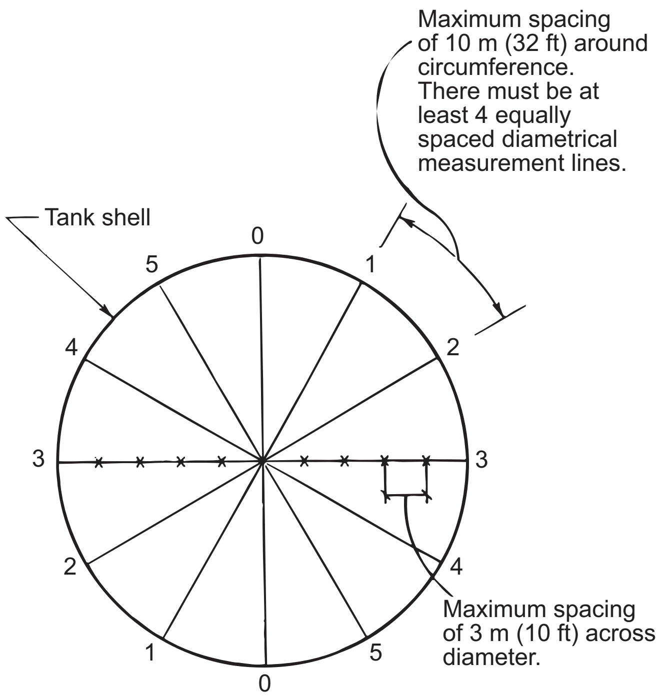
Measure bottom and edge settlement carefully, taking into account that measurements taken when the bottom is not in contact with the soil or foundation under the tank can overestimate or underestimate edge or bottom settlement significantly. If the measured settlement is near the maximum allowable settlement, consider repeating the measurement with the bottom forced down to the soil, e.g. standing on it, or take an additional set of measurements in the same area, where the bottom is in firm contact with the soil.



NOTE 1 There must be at least eight settlement points. The maximum spacing of the settlement points is 10 m (32 ft) around the circumference.

NOTE 2 Points shall be equally spaced around the tank shell. See 12.5.2 for method of determining the number of measurement points.

Figure B.1—Measurements of Shell Settlement (External)



NOTE See 12.5.2 for method of determining the number of measurement points.

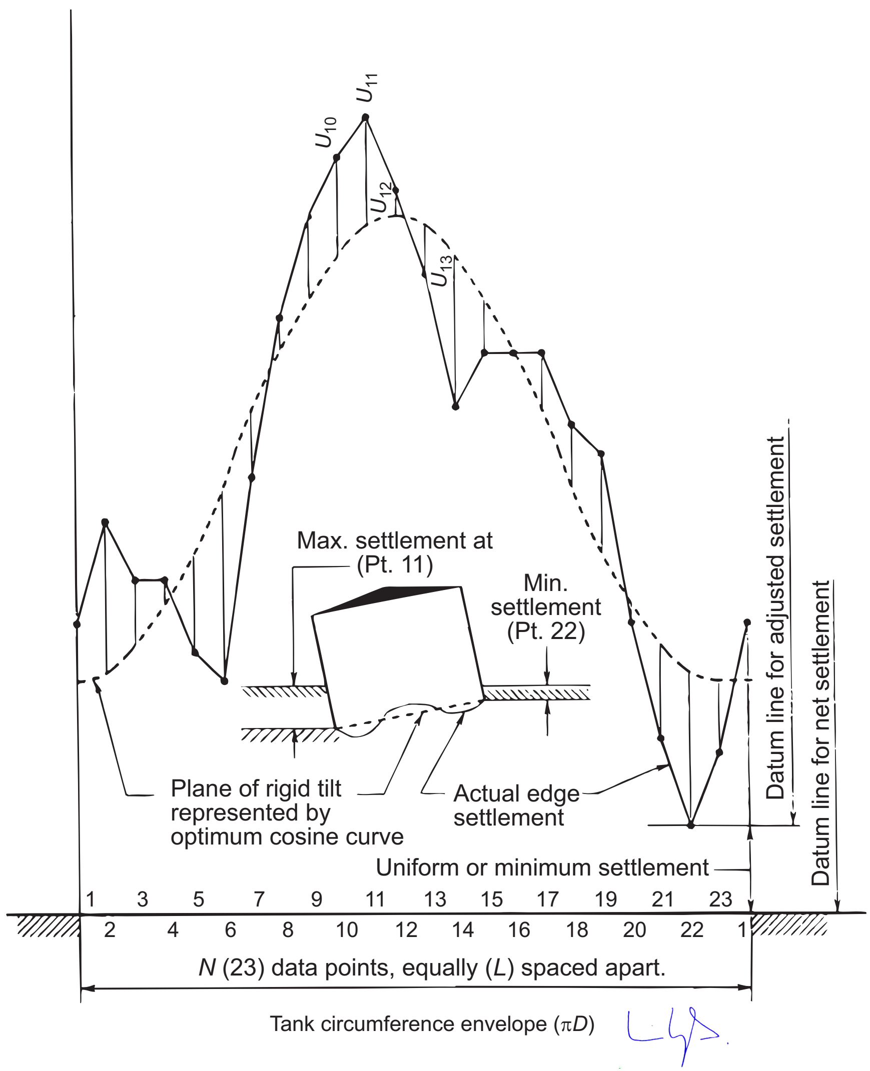
Figure B.2—Measurements of Bottom Settlement (Internal) Tank Out-of-service

B.2.2 Shell Settlement Evaluation

Settlement of a tank is the result of either one, or a combination of the following three settlement components.

B.2.2.1 *Uniform settlement.* This component often can be predicted in advance, with sufficient accuracy from soil tests. It may vary in magnitude, depending on the soil characteristics. Uniform settlement of a tank does not induce stresses in the tank structure. However, piping, tank nozzles, and attachments must be given adequate consideration to prevent problems caused by such settlement.

B.2.2.2 *Rigid body tilting of a tank (planar tilt).* This component rotates the tank in a tilted plane. The tilt will cause an increase in the liquid level and, therefore, an increase in the hoop stress in the tank shell. Also, excessive tilting can cause binding of peripheral seals in a floating roof and inhibit roof travel. This type of settlement could affect tank nozzles that have piping attached to them. Figure B.3 shows that the settled location of the tank shell, after rigid body tilt, can be represented by either a cosine or sine wave with respect to its original position in a horizontal plane.



Out-of-plane deflection for Point "i" is
$S_i = U_i - (^1/_2\,U_{i-1} + {}^1/_2\,U_{i+1})$, for example
$S_{11} = U_{11} - (^1/_2 U_{10} + {}^1/_2 U_{12})$

U_i = out-of-plane settlement of Point, "*i*"
(+) when above cos. curve;
(−) when below cos. curve, for example:
U_{11} = (+)
U_{13} = (−)

Figure B.3—Graphical Representation of Tank Shell Settlement per B.2.2.4

B.2.2.3 Due to the fact that a tank is a rather flexible structure, the tank may settle in a non-planar configuration, inducing additional stresses in the tank shell. The out-of-plane settlements of the shell can lead to out-of-roundness at the top of the shell, and depending on the extent of the induced out-of-roundness, may impede the proper functioning of the floating roof in such a way that re-leveling is required. The out-of-roundness caused by settlement may also affect internal roof support structures such as columns, rafters, and girders. Also, such settlements may cause flat spots to develop in the tank shell. This type of settlement could affect tank nozzles that have piping attached to them.

B.2.2.4 While uniform settlement and rigid body tilt of a tank may cause problems as described in B.2.2.1 and B.2.2.2, the out-of-plane settlement is the important component to determine and evaluate in order to ensure the structural integrity of the shell and bottom. Based on this principle, a common approach is to determine the magnitudes of the uniform settlement and rigid body tilt (if a rigid tilt plane exists or can be identified) for each data point on the tank periphery. If a plane of rigid tilt can be distinguished, it becomes important as a datum from which to measure the magnitudes of the out-of-plane settlements. When the out-of-plane settlement pattern of a tank has an easily distinguishable plane of rigid tilt, the methodology in this paragraph can be used to evaluate the acceptability of the tank's out-of-plane settlement. If a rigid tilt plane can not be readily determined, the methodology in B.2.2.5 can be used to evaluate the acceptability of the tank's out-of-plane settlement.

A graphical representation illustrating tank shell settlement with a rigid tilt plane well–defined by a cosine curve fit is shown in Figure B.3. The construction of this settlement plot has been developed in accordance with the following.

a) The actual settlement (in most cases an irregular curve) is plotted using points around the tank circumference as the abscissa.

b) The vertical distance between the abscissa and the lowest point on this curve (Point 22) is the minimum settlement, and it is called the uniform settlement component. A line through this point, parallel to the abscissa, provides a new base or datum line for settlement measurements called adjusted settlements.

c) The plane of rigid tilt settlement, if well-defined, is represented by the optimum cosine curve. Several methods exist for determining the optimum cosine curve. The least accurate method is by free hand drawing techniques, a kind of trial and error procedure to fit the best cosine curve through the data. A better method is to use the mathematical and graphical capabilities of a computer.

d) The vertical distances between the irregular curve and the cosine curve represent the magnitudes of the out-of-plane settlements (U_i at Data Point i).

e) A commonly used and accepted method is to use a computer to solve for constants a, b, and c, to find the optimum cosine curve of the form:

$$\mathrm{Elev}_{\mathrm{pred}} = a + b \times \cos(\theta + c)$$

Where $\mathrm{Elev}_{\mathrm{pred}}$ is the elevation predicted by the cosine curve at angle theta. A typical starting point for a computer best-fit cosine curve is a least-square fit where a, b, and c are chosen to minimize the sum of the square of the differences between measured and predicted elevations. The optimum cosine curve is only considered valid (i.e. accurately fits the measured data) if the value R^2 is greater than or equal to 0.9.

$$R^2 = \frac{(S_{yy} - SSE)}{S_{yy}}$$

where

S_{yy} is the sum of the squares of the differences between average measured elevation and the measured elevations;

SSE is the sum of the square of the differences between the measured and predicted elevations.

Linear least square fitting and the R^2 method of curve fitting are basic statistical tools. The use of a more rigorous statistical method to determine the optimum cosine curve, such as non-linear or iterative procedures, may be used by those experienced in their use.

Obtaining a statistically valid cosine curve may require taking more measurements than the minimums shown in Figure B.1. In many cases, the out-of-plane settlement may be concentrated in one or more areas. In such cases, the least-squares fit approach may under predict the local out-of-plane settlement and is not conservative. In these cases, R^2 will typically be less than 0.9, and more rigorous curve-fitting procedures should be considered. Alternatively, the settlement may not indicate a well-defined rigid tilt plane and the procedure in B.2.2.5 should be considered.

f) The vertical distances between the irregular curve and the optimum curve represent the magnitudes of the out-of-plane settlements (U_i at Data Point i). S_i is the out-of-plane deflection at Point i (see Figure B.3).

NOTE When determining the optimum cosine curve described in B.2.2.4 e), taking additional measurements around the shell will result in a more accurate cosine curve fit. However, using all of the measurement points in the equation shown in B.3.2.1 will result in very small allowable out-of-plane settlements, S_{max} since the arc length L between measurement points is small. It is acceptable to all measurement points to develop the optimum cosine curve, but only use a subset of these points spaced no further than 10 m (32 ft) (8 minimum) when calculating S_i and S_{max}.The points used must include the points furthest from the optimum cosine curve. For example, if 8 points are required, but 16 measurements are taken, and the arc length between measurement points is only 15 ft, calculate the optimum cosine curve using all 16 points, but use only 8 points to calculate S_i . The equations in Figure B.3 would be revised to read:

$$S_i = U_i - (1/2\ U_{i-2} + 1/2\ U_{i+2})$$

$$S_{11} = U_{11} - (1/2\ U_9 + 1/2\ U_{13})$$

B.2.2.5 If a well-defined rigid tilt plane can not be determined or the maximum out-of-plane deflection determined in accordance with B.3.2.1 is exceeded, the procedures given in this section may be used in lieu of more rigorous analysis or repair.

B.2.2.5.1 For settlement profiles without a well-defined rigid tilt plane, the settlement arc length, S_{arc}, and out-of-plane deflection at the point under consideration, S_i, must be determined from a plot of the measurement data. Figure B.4 is a graphical illustration of the various measurement terms and procedures for determining estimates of the settlement arc length and the corresponding out-of-plane deflection, including the refinement of measurements, when needed.

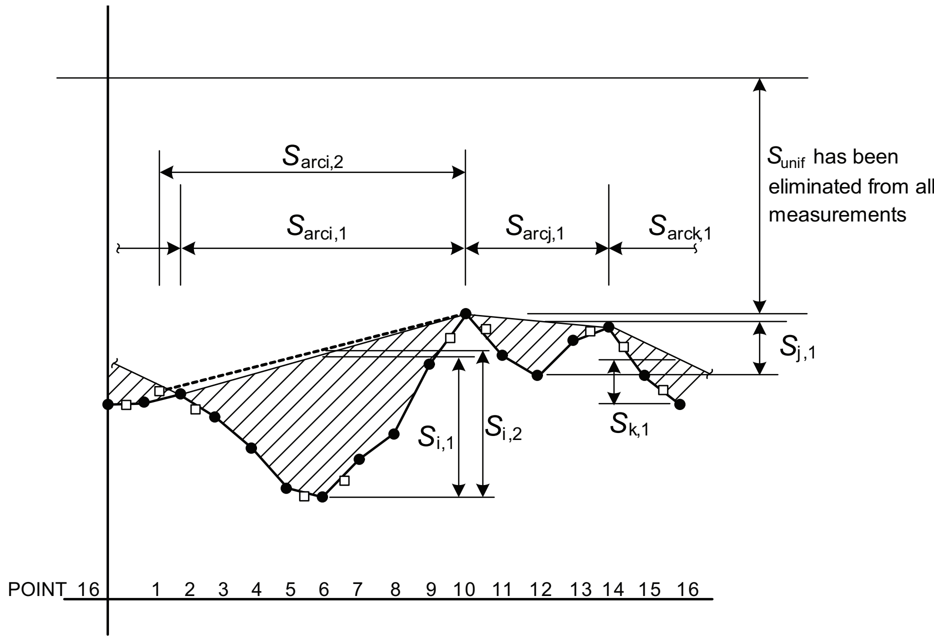
a) The actual settlement is plotted using points around the tank circumference as the abscissa.

b) An initial settlement arc length and maximum settlement is determined from the points on the plotted data that indicate a change in direction of settlement slope (see Figure B.4).

c) Additional settlement measurement points may be needed halfway between the points indicating a change in direction of the settlement slope to further refine the settlement arc length and location and magnitude of maximum settlement.

d) Step c) may need to be repeated. The best estimate of the settlement arc length and maximum out-of-plane deflection shall be considered in the procedure given in B.3.2.2.

B.2.2.5.2 If a valid cosine fit of the rigid tilt plane can be determined, but the maximum out-of-plane deflection determined in accordance with B.3.2.1 is exceeded, the procedure in B.3.2.2 may be used to evaluate the settlement. In this case, see Figure B.5 for a graphical illustration of the determination of the settlement arc length and the corresponding out-of-plane deflection.



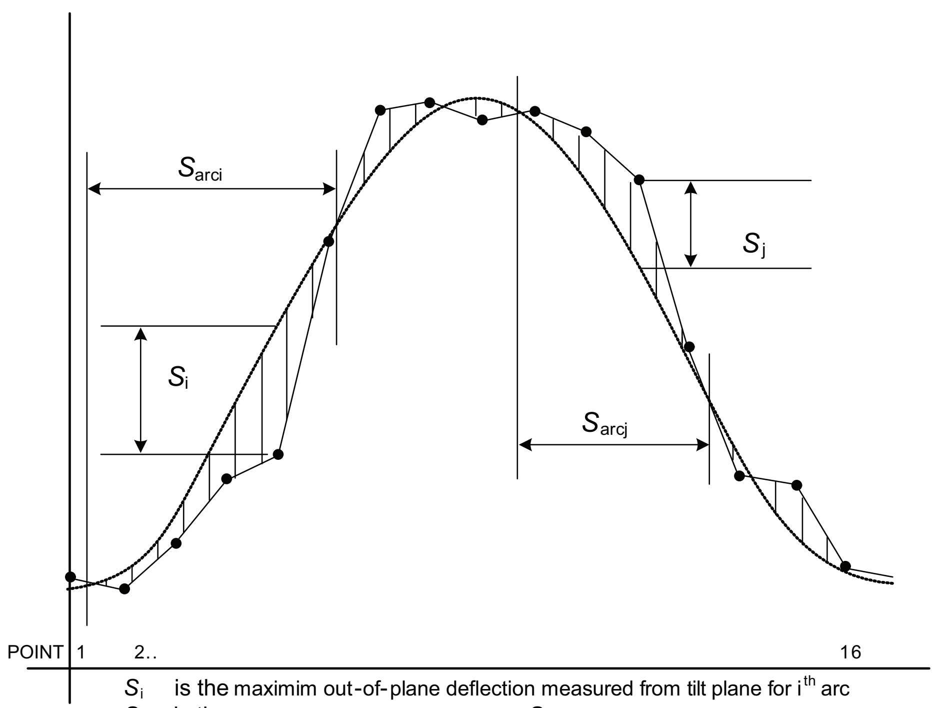
● initial 16 measurements

□ additional measurements to better define settlement arc and maximum settlement

$S_{i,N}$ is the maximum out-of-plane deflection measured from indicated plane, Nth estimate

$S_{arci,N}$ is the settlement arc corresponding to $S_{i,N}$

Figure B.4—Graphical Representation of Shell Settlement per B.2.2.5 (Tilt Plane Not Described by an Optimal Cosine Curve)



S_i is the maximim out-of-plane deflection measured from tilt plane for ith arc

S_{arci} is the settlement arc corresponding to S_i

S_{unif} has been eliminated from all measurements

Figure B.5—Graphical Representation of Shell Settlement per B.2.2.5 (Tilt Plane Described by an Optimal Cosine Curve)

B.2.2.5.3 If an examination of the measured settlement plot indicates a fold pattern about a diameter of the tank, the maximum out-of-plane settlement should be determined using a settlement arc length of 50 % of the tank's circumference.

B.2.3 Edge Settlement

B.2.3.1 Edge settlement occurs when the tank shell settles sharply around the periphery, resulting in deformation of the bottom plate near the shell-to-bottom corner junction. Figure B.6 illustrates this settlement.

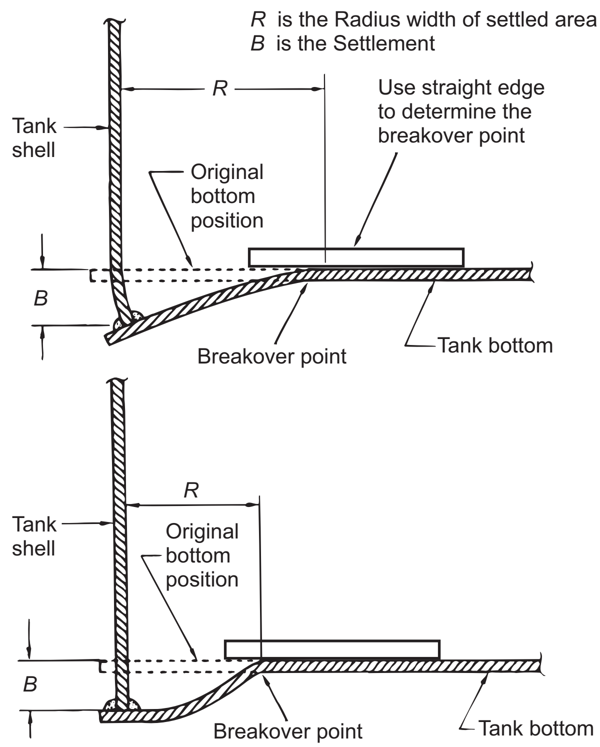


Figure B.6—Edge Settlement

B.2.3.2 The equation given in B.3.4 can be used to evaluate edge settlement. Alternatively, a rigorous stress analysis can be carried out for the deformed profile. The determination of the deformed profile should take into consideration the following.

a) Locating the breakover point where the settled area begins requires some judgment. Placing a straight edge on the unsettled bottom as shown in Figure B.6, and observing where the bottom separates from the straight edge will help define the breakover point.

b) If the tank bottom is cone up or cone down, the settlement B, should be measured from a projection of the unsettled bottom, not from level. See Figure B.7.

B.2.3.3 The measured edge settlement B is defined as shown in Figure B.6. B_{ew} is defined as the allowable edge settlement in an area where there is a bottom lap weld in the settled area that is essentially parallel (±20°) to the shell. B_e is defined as the allowable settlement in an area with no bottom welds, or only butt welds in the bottom, or lap welds in the bottom that are essentially perpendicular (±20°) to the shell.

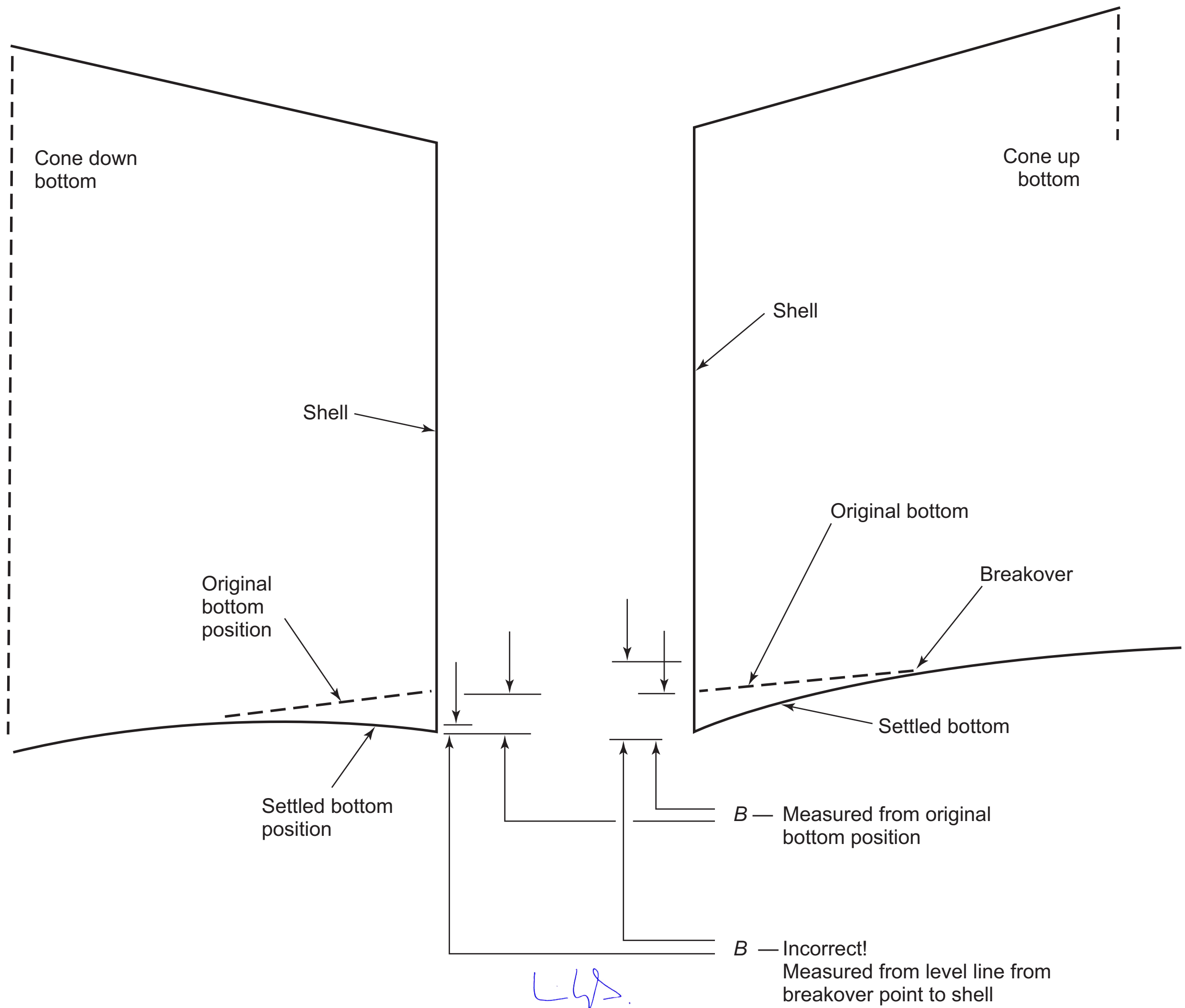


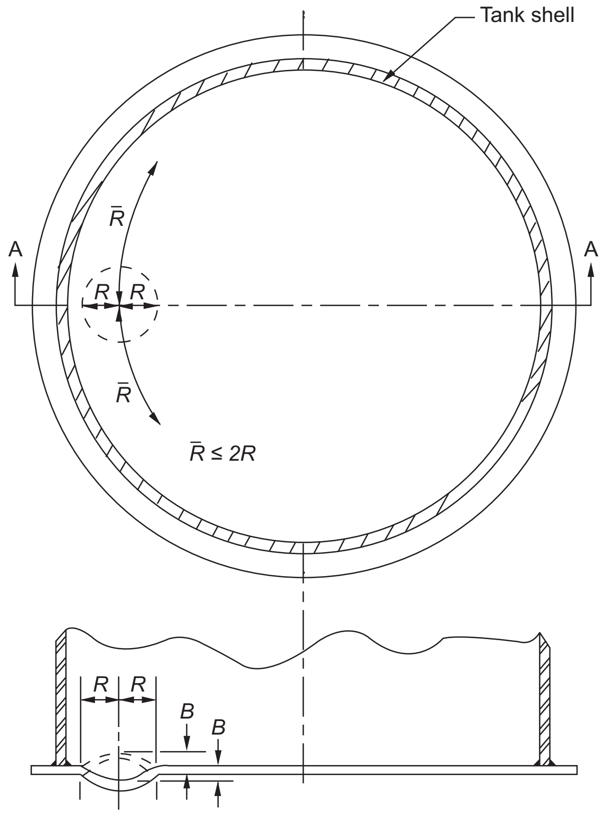
Figure B.7—Correction for Measured Edge Settlement

B.2.3.4 Section B.3.4 provides methods for evaluation of measured edge settlement B against allowable edge settlement B_{ew} and B_e. Since B_{ew} is more conservative than B_e, the simplest approach is to initially evaluate measured settlement B against B_{ew} for all settled areas. If all areas meet this criterion, the settlement is acceptable and no further evaluation is necessary. If necessary, different settled areas can be evaluated separately against B_{ew} and B_e. For areas containing lap welds at an arbitrary angle to the shell, interpolation to find an allowable settlement between B_{ew} and B_e based on the angle of the weld to the shell is allowed.

B.2.4 Bottom Settlement Near the Tank Shell

B.2.4.1 Figure B.8 illustrates bottom settlement near the tank shell.

B.2.4.2 The equation given in B.3.3 can be used to evaluate settlement near the tank shell. Alternatively, a rigorous stress analysis can be carried out for the deformed profile.



SECTION A-A

R is the radius of inscribed circle in bulged or depressed area
B is the settlement or depression depth or height of bulge

Figure B.8—Bottom Settlement Near Shell

B.2.5 Localized Bottom Settlement Remote from the Tank Shell

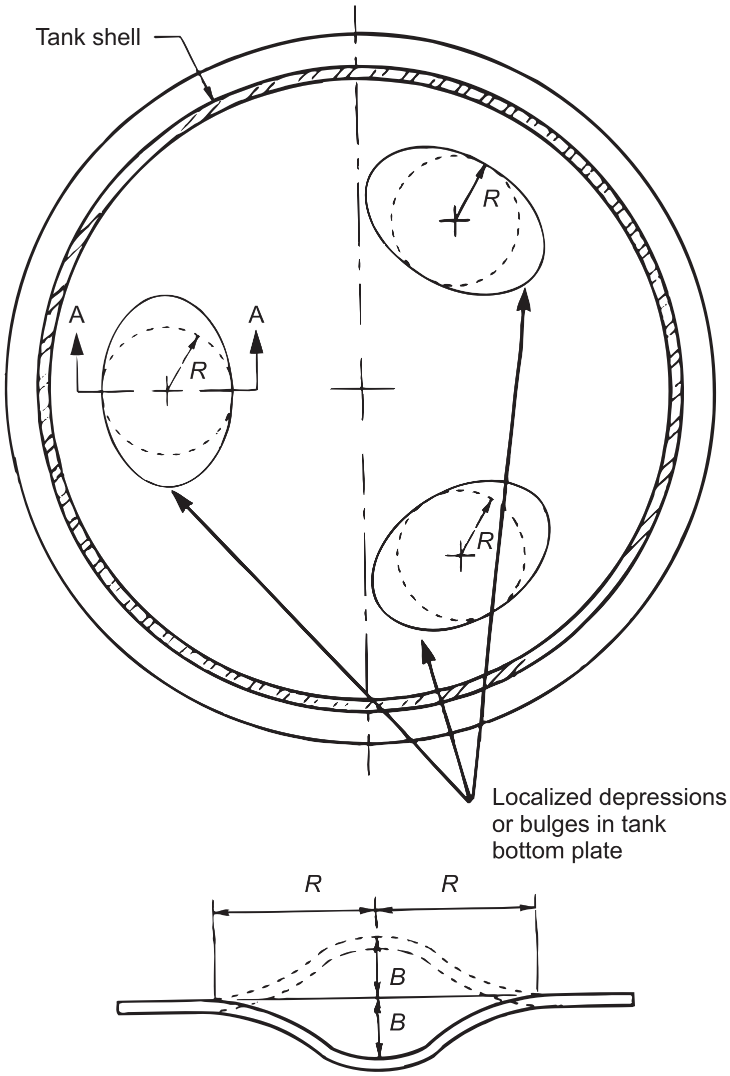
B.2.5.1 Localized bottom settlement remote from tank shell are depressions (or bulges) that occur in a random manner, remote from the shell (see Figure B.9).

B.2.5.2 Acceptability of these localized settlements is dependent on localized stresses in the bottom plate, design and quality of the lap welds (single-pass or multi-pass), and voids below the bottom plate. The equation given in B.3.3 can be used to evaluate localized settlement remote from the tank shell. These limits are applicable to tank bottoms that have single-pass lap-welded joints.

B.3 Determination of Acceptable Settlement

B.3.1 General

For existing tanks with history of successful service, it may be possible to accept greater settlement and distortion of the foundation from a true plane than new tank construction standards allow. Each tank must be evaluated based on service conditions, materials of construction, soil characteristics, tank foundation design, and tank service history. The methods discussed in following sections are not mandatory and approximate the maximum permissible settlement. However, experience has shown that if settlements exceed the following requirements, further assessment or repair is required.



R is the radius of inscribed circle in bulged or depressed area

B is the settlement depth or height of bulge

SECTION A-A

Figure B.9—Localized Bottom Depressions or Bulges Remote from Shell

B.3.2 Permissible Out-of-plane Settlement

From the measurements procedures described in B.2.2.4 and B.2.2.5, determine the maximum out-of-plane settlement. The magnitude (absolute value) of the maximum settlement shall be compared to the permissible values given in B.3.2.1 or B.3.2.2, as applicable. The permissible out-of-plane settlement given in B.3.2.1 and B.3.2.2 do not take into consideration abrupt changes in shell elevation (ridges) or discontinuities near the bottom of the tank in the settled region, such as low nozzles. They also do not consider fold patterns in cone roof tanks when the fold line is adjacent to or through a line of one or more roof columns, or to patterns of settlement that include combined shell and edge settlements. The permissible settlement criteria in B.3.2.2 are applicable to API 650 carbon steel and stainless steel tanks and diameter ranges given in B.3.2.2. Out-of-plane settlement that does not meet these limitations should be further examined by a more rigorous engineering assessment to determine the need for repairs, see B.3.2.4

B.3.2.1 When using the procedure with an optimal cosine curve approach defined in B.2.2.4 to determine out-of-plane deflection, the permissible out-of-plane deflection is given by the following equation (see Note):

In SI units: $S_{max} = \dfrac{(L^2 \times Y \times 11)}{2[(E \times H)]}$

where

S_{max} is permissible out-of-plane deflection, in meters (m);

L is arc length between measurement points, in meters (m);

Y is yield strength of the shell material, in megapascals (MPa);

E is Young's Modulus, in pound force per megapascals (MPa);

H is tank height, in meters (m).

In USC units: $S_{max} = \dfrac{(L^2 \times Y \times 11)}{2[(E \times H)]}$

where

S_{max} is permissible out-of-plane deflection, in feet (ft);

L is arc length between measurement points, in feet (ft);

Y is yield strength of the shell material, in pound force per square inch (lbf/in.^{2});

E is Young's Modulus, in pound force per square inch (lbf/in.^{2});

H is tank height, in feet (ft).

NOTE This equation is based on "Criteria for Settlement of Tanks," W. Allen Marr, M. ASCE, Jose A. Ramos, and T. William Lambe, F. ASCE, *Journal of Geotechnical Engineering Division*, Proceedings of the American Society of Civil Engineers, Vol. 108, August, 1982.

B.3.2.2 When using the procedure in B.2.2.5 to determine out-of-plane deflection, the permissible out-of-plane deflection is given by the following equation (see Note):

In SI units: $S_{max} = \min\left[K \times S_{arc} \times \left(\frac{D}{H}\right) \times \left(\frac{Y}{E}\right), 4.0\right]$

Tank Diameter m	Open Top Tanks, K	Fixed Roof Tanks, K
$D \leq 15.2$	2.40	.88
$15.2 < D \leq 23.4$	.65	.48
$23.4 < D \leq 36.6$	.54	.32
$36.6 < D \leq 54.9$	.33	.19
$54.9 < D \leq 73.2$	.30	—
$73.2 < D \leq 91.4$	.20	—
$91.4 \leq D$	—	—

where

S_{max} is permissible out-of-plane deflection, in meters (m);

S_{arc} is effective settlement arc, see B.2.2.5.1, in millimeters (mm);

D is tank diameter, in meters (m);

Y is yield strength of the shell material, in megapascals (MPa);

E is Young's Modulus, in megapascals (MPa);

H is tank height, in meters (m).

In USC units: $S_{max} = \min\left[K \times S_{arc} \times \left(\frac{D}{H}\right) \times \left(\frac{Y}{E}\right), 100\right]$

Tank Diameter ft	Open Top Tanks, K	Fixed Roof Tanks, K
$D \leq 50$	28.7	10.5
$50 < D \leq 80$	7.8	5.8
$80 < D \leq 120$	6.5	3.9
$120 < D \leq 180$	4.0	2.3
$180 < D \leq 240$	3.6	—
$240 < D \leq 300$	2.4	—
$300 < D$	—	—

where

S_{max} is permissible out-of-plane deflection, in inches (in.);

S_{arc} is effective settlement arc, see B.2.2.5.1, in feet (ft);

D is tank diameter, in feet (ft);

Y is yield strength of the shell material, in pound force per square inch (lbf/in.^{2});

E is Young's Modulus, in pound force per square inch (lbf/in.^{2});

H is tank height, in feet (ft).

NOTE This equation is based on "Final Report on the Study of Out-of-Plane Tank Settlement," J. Andreani, N. Carr, Report to API SCAST, May, 2007.

B.3.2.3 Serviceability may also be a concern for tanks with significant out-of-plane deflection. Out-of-roundness can impede floating roof operation and also affect internal roof support structures. The out-of-roundness that a tank experiences with out-of-plane deflection is fairly sensitive to the actual pattern of settlement. The owner/operator may wish to specify additional inspection or a more rigorous assessment of the tank's out-of-roundness.

B.3.2.4 If out-of-plane deflection exceeds the applicable limits described in B.3.2.1 or B.3.2.2, a more rigorous evaluation may be performed to determine the need for repairs. This evaluation should be done by an engineer experienced in tank settlement analysis.

B.3.3 Internal Bottom Settlements or Bulges

Measure the bulge or depression. The permissible bulge or depression is given by the following equation (see Note).

In SI units: $B_B = 0.031R$

where

B_B is maximum height of bulge or depth of local depression, in millimeters (mm);

R is radius of inscribed circle in bulged area or local depression, in millimeters (mm).

In USC units: $B_B = 0.37R$

where

B_B is maximum height of bulge or depth of local depression, in inches (in.);

R is radius of inscribed circle in bulged area or local depression, in feet (ft).

Figure B.10 is a graphical representation of this equation.

NOTE This equation is based on "Criteria for Settlement of Tanks," W. Allen Marr, M. ASCE, Jose A. Ramos, and T. William Lambe, F. ASCE, *Journal of Geotechnical Engineering Division*, Proceedings of the American Society of Civil Engineers, Vol. 108, August 1982.

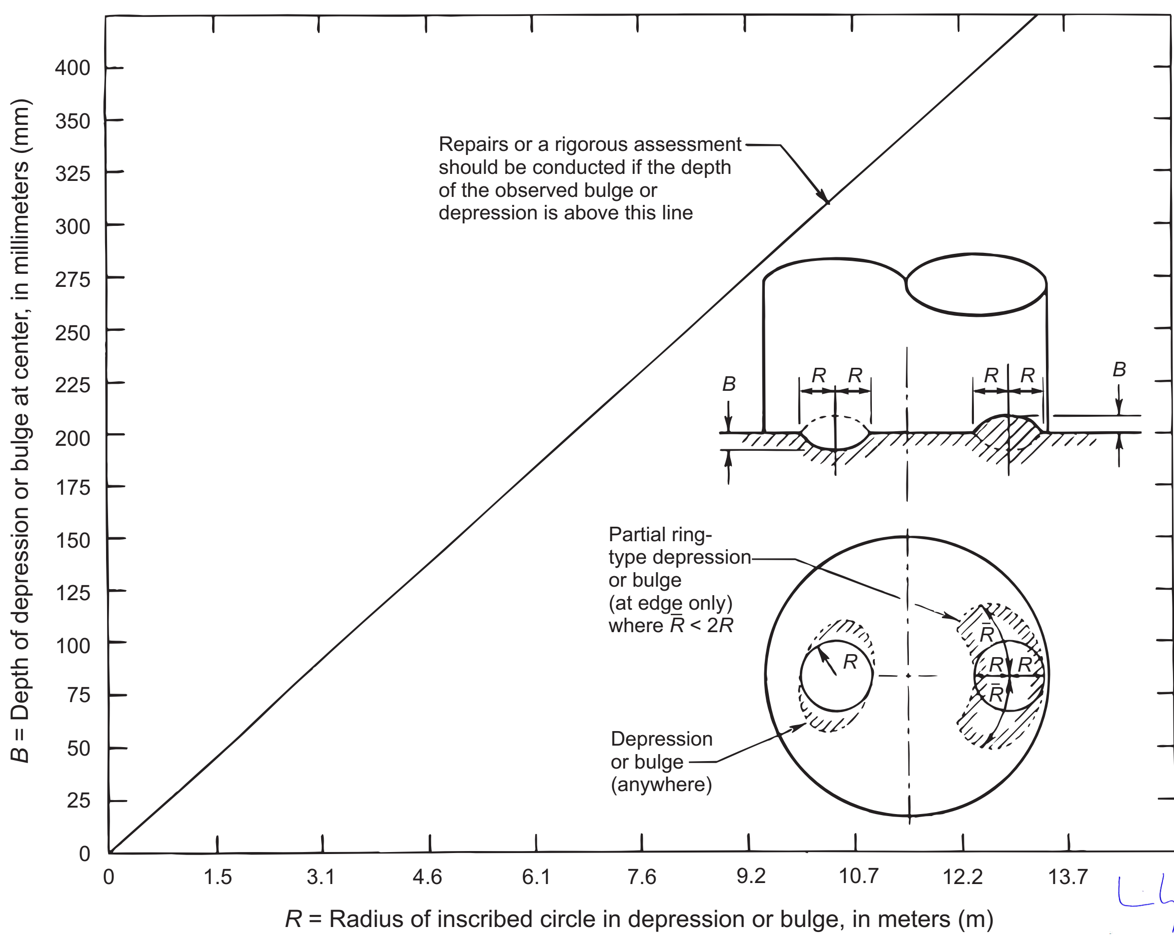


Figure B.10a—Localized Tank Bottom Settlement Limits for Single Pass Welds, in SI Units

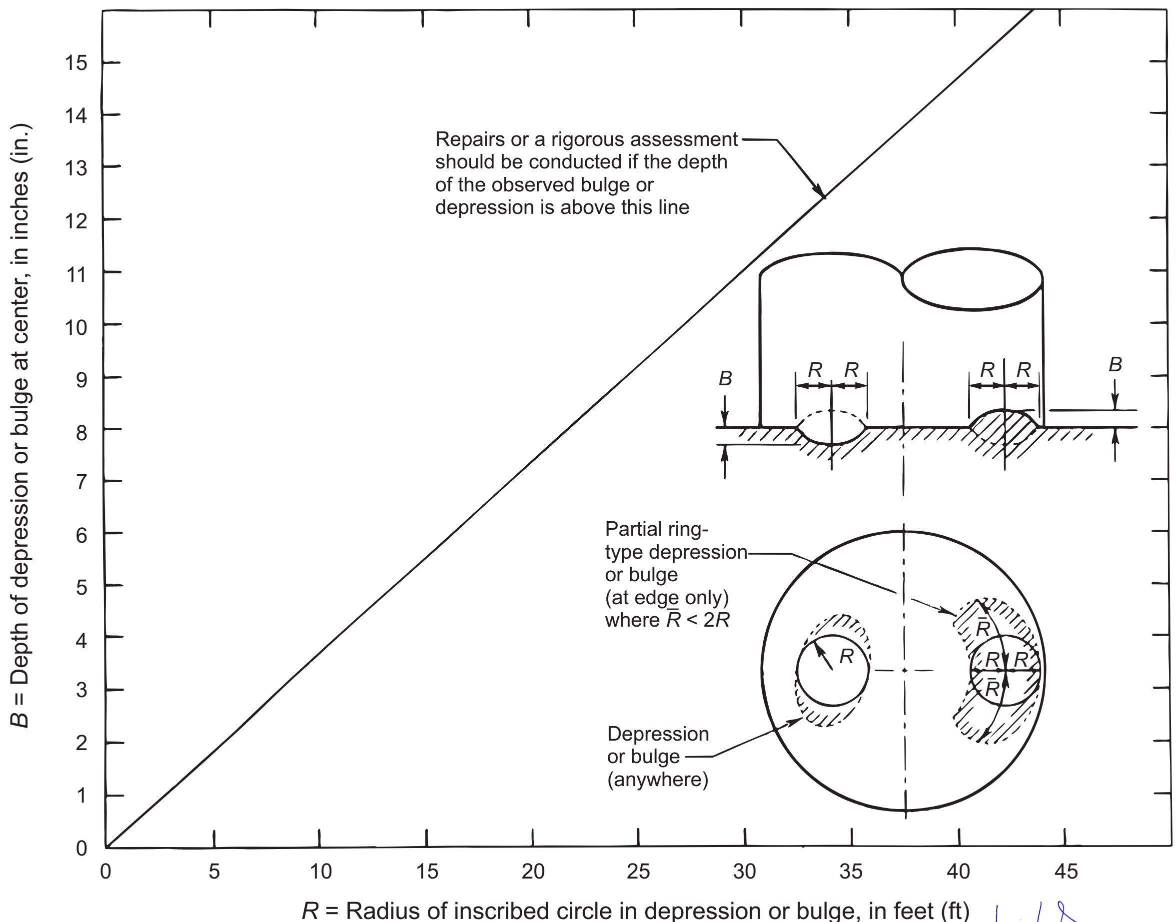


Figure B.10b—Localized Tank Bottom Settlement Limits for Single Pass Welds, in USC Units

B.3.4 Edge Settlement

B.3.4.1 Maximum allowable settlement B_{ew} is shown in Figure B.11 for settled areas that include bottom lap welds essentially parallel to the shell (±20°). In settled areas where the measured settlement B exceeds 75 % of allowed settlement B_{ew}, all shell-to-bottom welds and bottom welds should be examined visually and with magnetic particle or liquid penetrant methods. All indications should be repaired, or evaluated for risk of brittle fracture, and/or fatigue failure prior to returning the tank to service.

B.3.4.2 For settled areas where measured settlement B exceeds 75 % of B_{ew}, any welds within 300 mm (12 in.) of either side of the breakover area (see Figure B.6) should be examined visually. Any suspect areas should be examined with either magnetic particle examination or liquid penetrant examination. All indications should be repaired or evaluated for risk of fatigue prior to returning the tank to service.

B.3.4.3 Maximum allowable settlement B_e is shown in Figure B.12 for areas of edge settlement with no welds, butt welds, or lap welds in the bottom that are essentially perpendicular to the shell (±20°). In settled areas where the measured settlement exceeds 75 % of the allowed settlement, all shell-to-bottom welds and bottom welds should be examined visually and with magnetic particle or liquid penetrant methods. All indications should be repaired or evaluated for risk of brittle fracture and/or fatigue prior to returning the tank to service.

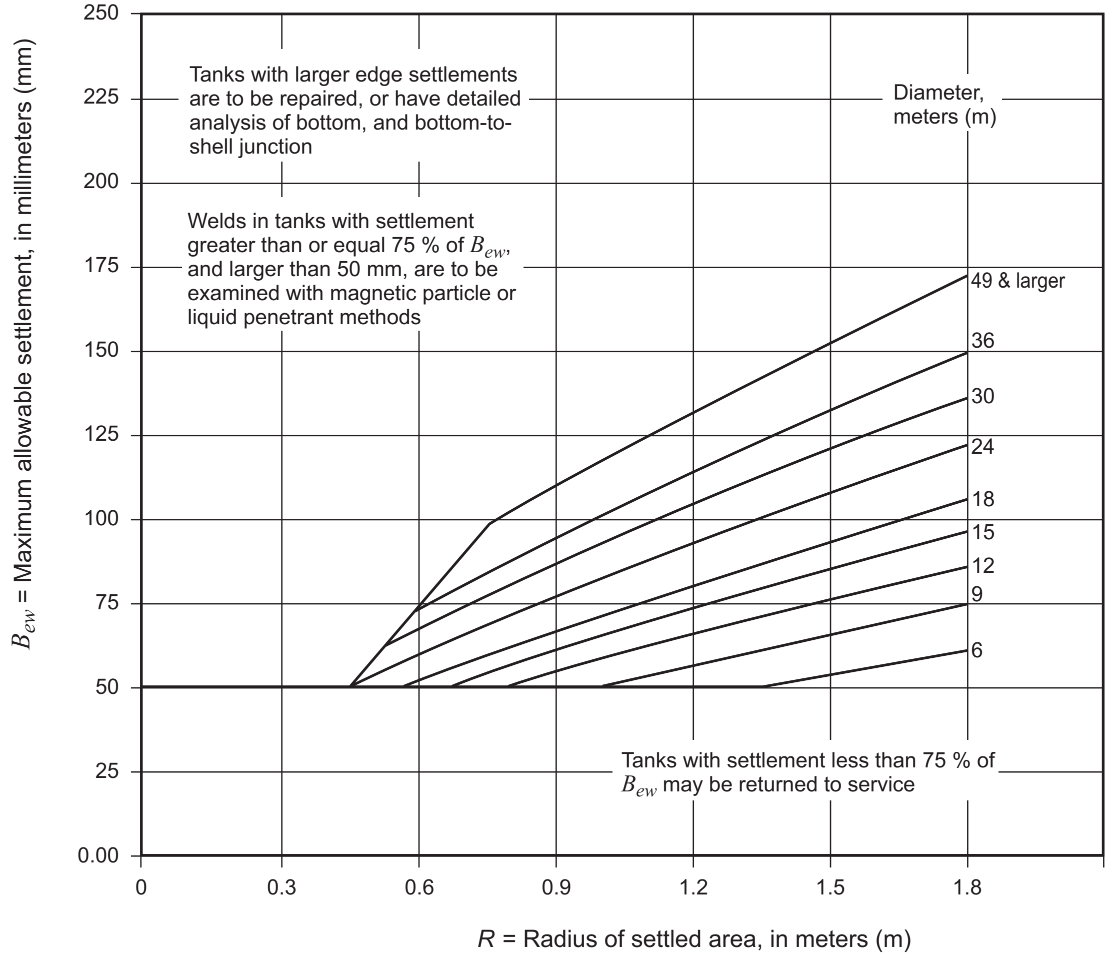


Figure B.11a—Maximum Allowable Edge Settlement for Areas with Bottom Lap Welds Approximately Parallel to the Shell, in SI Units

B.3.4.4 Maximum allowable settlement for areas of edge settlement with a lap weld at an arbitrary angle to the shell may be interpolated from B_e and B_{ew} from Figure B.11 and Figure B.12, and the following equation:

$$B_\alpha = B_e - (B_e - B_{ew}) \times \sin \alpha$$

Where α is the angle of the weld to a tank centerline and B_α is the allowable settlement for an area with a weld at that angle (see Figure B.13).

B.3.4.5 In general, settlement occurs slowly, and for most existing tanks, the majority of settlement is presumed to have occurred in the first few years of service. Significant additional settlement will not be expected after the initial inspections. Therefore, typical practice is to compare the measured edge settlement with the maximum allowable edge settlement B_{ew} and B_e, and not include allowance for additional settlement during subsequent operation. Note that erosion of the pad adjacent to the tank may cause local settlement. In this case the settlement will continue unless the pad is repaired and future erosion prevented. For cases where significant additional settlement is expected, an engineer experienced in tank settlement evaluation should evaluate the settlement expected at the next inspection with the limits in B.3.4. This is analogous to a corrosion allowance for components expected to corrode.

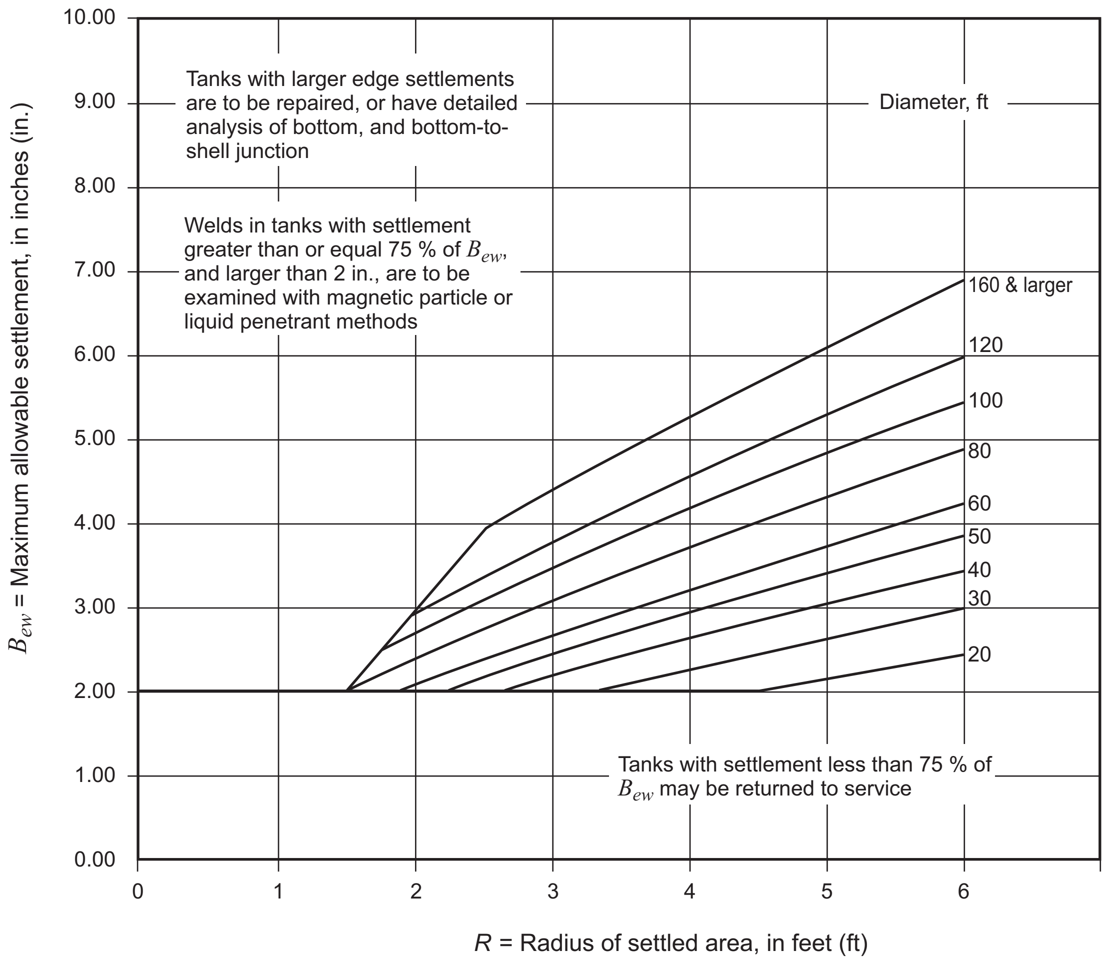


Figure B.11b—Maximum Allowable Edge Settlement for Areas with Bottom Lap Welds Approximately Parallel to the Shell, in USC Units

B.3.4.6 The edge settlement limits described in B.2.3.1 through B.2.3.4 were developed for typical 6 mm ($^{1}/_{4}$-in.) thick tank bottoms with minimal corrosion.

a) Edge settlement limits can be applied with reasonable accuracy to 8 mm ($^{5}/_{16}$ in.) and 10 mm ($^{3}/_{8}$ in.) hick tank bottoms.

b) Edge settlement limits can be applied with reasonable accuracy to bottoms with general corrosion, as long as the areas near all welds are thicker than 5 mm ($^{3}/_{16}$ in.).

c) Edge settlement limits can be applied with reasonable accuracy to bottoms with local corrosion, if all locally thin areas in the settled area (closer than "R" to the shell) thinner than 5 mm ($^{3}/_{16}$ in.) are smaller than 300 mm (12 in.) in diameter and the thin area does not include a weld.

d) Settlement is presumed to be slow, and a small amount of additional settlement is expected to occur prior to the next inspection.

B.3.4.7 Edge settlement increases secondary stress at the bottom-to-shell weld. If weld repairs are made to the bottom-to-shell weld in an area where settlement exceeds $^{1}/_{2}$ of B_e, these additional stresses should be evaluated by an engineer experienced in tank settlement evaluation before waiving a hydrostatic test per 12.3.

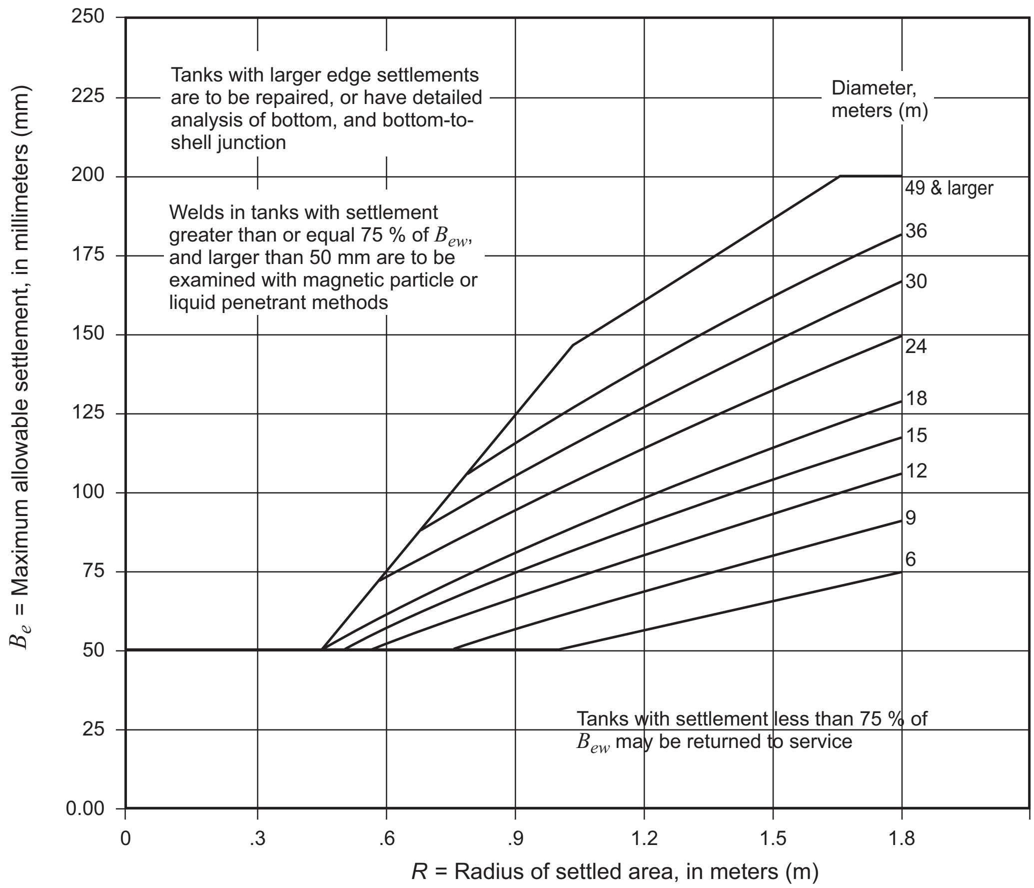


Figure B.12a—Maximum Allowable Edge Settlement for Areas with Bottom Lap Welds Approximately Perpendicular to the Shell, in SI Units

B.4 Repairs

B.4.1 If it is determined that settlements have occurred which are beyond the permissible limits established in the previous sections, then consideration should be given to making repairs or a rigorous stress analysis should be performed to evaluate the deformed profile. Various repair techniques have been discussed above. The judgment on repairs should be tempered with knowledge of tank service history, previous repairs, previous inspections, tank foundation conditions, soil characteristics, the material of construction, and estimates of future settlement. See 9.11 for suggested repair details.

B.4.2 For tanks with edge settlement exceeding the limits and assumptions given in B.2.3.1 through B.2.3.7, the tank should be repaired. Any plate exceeding acceptable strains (typically 2 % to 3 %) should be replaced. Re-leveling the tank will not remove the plastic strain, so leveling the tank without replacing the strain may not be a sufficient repair. Welds in the area of the high strains should be removed and replaced, or be subjected to a fitness-for-service evaluation by an engineer experienced in tank settlement evaluation. The condition leading to the unacceptable settlement should be corrected. Depending on the severity and location of the settlement, required repairs may include regrading the soil under the tank bottom, and/or repairing the foundation. Jacking and re-leveling the shell may be required to prevent additional settlement damage. Jacking and leveling are usually done in conjunction with, not instead of, replacing damaged plate and welds. In lieu of repairs, a detailed analysis of the settled area may be performed by an engineer experienced in tank design and settlement evaluation. The analysis should consider primary and secondary stress and the risk of brittle fracture.

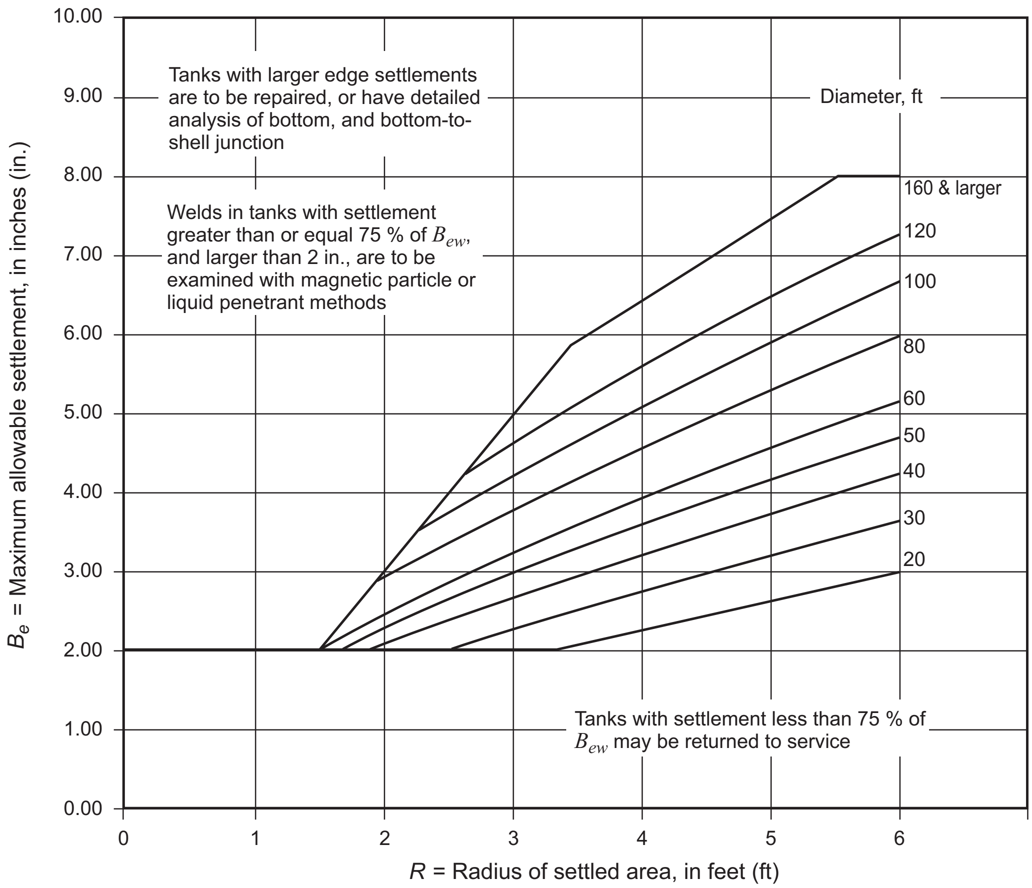


Figure B.12b—Maximum Allowable Edge Settlement for Areas with Bottom Lap Welds Approximately Perpendicular to the Shell, in USC Units

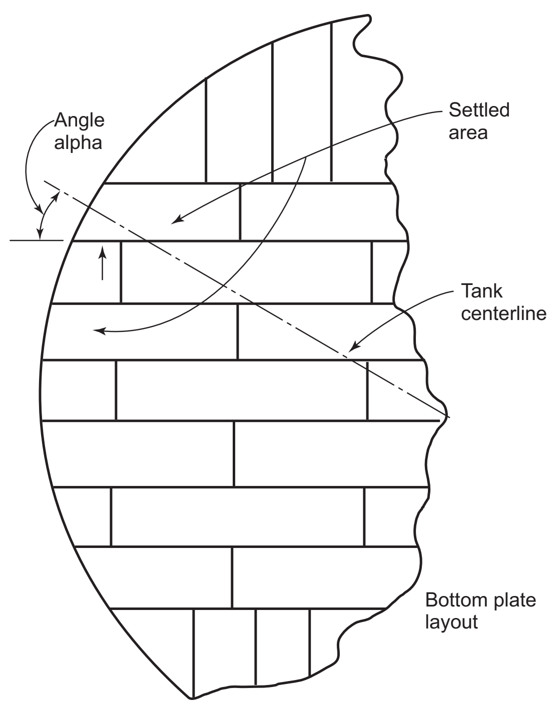


Figure B.13—Edge Settlement with a Lap Weld at an Arbitrary Angle to the Shell

Annex C
(informative)

Checklists for Tank Inspection

Annex C contains sample checklists illustrating tank components and auxiliary items that should be considered for internal and external inspection of tanks. This information is provided as guidance to the owner/operator for developing an inspection assessment schedule for any specific tank installation. The checklist format facilitates the recording of inspection findings.

NOTE 1 Users of checklists should not rely exclusively on the information contained in this document. Sound business, scientific, engineering, and safety judgment should be used in employing the information contained herein.

NOTE 2 Where applicable, authorities having jurisdiction should be consulted.

Table C.1—Tank In-service Inspection Checklist

	Item	Completed √	Comments
C.1.1	**Foundation**		
	Measure foundation levelness and bottom elevations (see Annex B for extent of measurements).		
C.1.1.1	**Concrete Ring**		
	a) Inspect for broken concrete, spalling, and cracks, particularly under backup bars used in welding butt-welded annular rings under the shell.		
	b) Inspect drain openings in ring, back of waterdraw basins and top surface of ring for indications of bottom leakage.		
	c) Inspect for cavities under foundation and vegetation against bottom of tank.		
	d) Check that runoff rainwater from the shell drains away from tank.		
	e) Check for settlement around perimeter of tank.		
C.1.1.2	**Asphalt**		
	a) Check for settling of tank into asphalt base which would direct runoff rain water under the tank instead of away from it.		
	b) Look for areas where leaching of oil has left rock filler exposed, which indicates hydrocarbon leakage.		
C.1.1.3	**Oiled Dirt or Sand**		
	Check for settlement into the base which would direct runoff rain water under the tank rather than away from it.		
C.1.1.4	**Rock**		
	Presence of crushed rock under the steel bottom usually results in severe underside corrosion. Make a note to do additional bottom plate examination (ultrasonic, hammer testing, or turning of coupons) when the tank is out of service.		
C.1.1.5	**Site Drainage**		
	a) Check site for drainage away from the tank and associated piping and manifolds.		
	b) Check operating condition of the dike drains.		
C.1.1.6	**Housekeeping**		
	Inspect the area for buildup of trash, vegetation, and other inflammables buildup.		
C.1.1.7	**Cathodic Protection**		
	Review cathodic protection potential readings.		
C.1.2	**Shells**		
C.1.2.1	**External Visual Inspection**		
	a) Visually inspect for paint failures, pitting, and corrosion.		
	b) Clean off the bottom angle area and inspect for corrosion and thinning on plate and weld.		
	c) Inspect the bottom-to-foundation seal, if any.		
C.1.2.2	**Internal (Floating Roof Tank)**		
	Visually inspect for grooving, corrosion, pitting, and coating failures.		
C.1.2.3	**Riveted Shell Inspection**		
	a) Inspect external surface for rivet and seam leaks.		
	b) Locate leaks by sketch or photo (location will be lost when shell is abrasive cleaned for painting).		
	c) Inspect rivets for corrosion loss and wear.		
	d) Inspect vertical seams to see if they have been full fillet lap-welded to increase joint efficiency.		

Table C.1—Tank In-service Inspection Checklist (Continued)

	Item	Completed √	Comments
	e) If no record exists of vertical riveted seams, dimension and sketch (or photograph) the rivet pattern: number of rows, rivet size, pitch length, and note whether the joint is butt-riveted or lap-riveted.		
C.1.2.4	**Wind Girder (Floating Roof Tanks)**		
	a) Inspect wind girder and handrail for corrosion damage (paint failure, pitting, corrosion product buildup), especially where it occurs at tack-welded junction, and for broken welds.		
	b) Check support welds to shell for pitting, especially on shell plates.		
	c) Note whether supports have reinforcing pads welded to shell.		
C.1.3	**Shell Appurtenances**		
C.1.3.1	**Manways and Nozzles**		
	a) Inspect for cracks or signs of leakage on weld joint at nozzles, manways, and reinforcing plates.		
	b) Inspect for shell plate dimpling around nozzles, caused by excessive pipe deflection.		
	c) Inspect for flange leaks and leaks around bolting.		
	d) Inspect sealing of insulation around manways and nozzles.		
	e) Check for inadequate manway flange and cover thickness on mixer manways.		
C.1.3.2	**Tank Piping Manifolds**		
	a) Inspect manifold piping, flanges, and valves for leaks.		
	b) Inspect fire-fighting system components.		
	c) Check for anchored piping which would be hazardous to the tank shell or bottom connections during earth movement.		
	d) Check for adequate thermal pressure relief of piping to the tank.		
	e) Check operation of regulators for tanks with purge gas systems.		
	f) Check sample connections for leaks and for proper valve operation.		
	g) Check for damage and test the accuracy of temperature indicators.		
	h) Check welds on shell-mounted davit clips above valves 6 in. and larger.		
C.1.3.3	**Autogauge System**		
	a) Inspect autogauge tape guide and lower sheave housing (floating swings) for leaks.		
	b) Inspect autogauge head for damage.		
	c) Bump the checker on autogauge head for proper movement of tape.		
	d) Identify size and construction material of autogauge tape guide (floating roof tanks).		
	e) Ask operator if tape tends to hang up during tank roof movement (floating roof tanks).		
	f) Compare actual product level to the reading on the autogauge (maximum variation is 50 mm [2 in.]).		
	g) On floating roof tanks, when the roof is in the lowest position, check that no more than two ft of tape are exposed at the end of the tape guide.		
	h) Inspect condition of board and legibility of board-type autogauges.		
	i) Test freedom of movement of marker and float.		
C.1.3.4	**Shell-mounted Sample Station**		
	a) Inspect sample lines for function of valves and plugging of lines, including drain or return-to-tank line.		
	b) Check circulation pump for leaks and operating problems.		

Table C.1—Tank In-service Inspection Checklist (Continued)

Item		Completed √	Comments
	c) Test bracing and supports for sample lines and equipment.		
C.1.3.5	**Heater (Shell Manway Mounted)**		
	Inspect condensate drain for presence of oil indicating leakage.		
C.1.3.6	**Mixer**		
	a) Inspect for proper mounting flange and support.		
	b) Inspect for leakage.		
	c) Inspect condition of power lines and connections to mixer.		
C.1.3.7	**Swing Lines: Winch Operation**		
	a) Nonfloating. Raise, then lower the swing line with the winch, and check for cable tightness to confirm that swing line lowered properly.		
	b) Floating. With tank half full or more, lower the swing line, then let out cable and check if swing has pulled cable tight, indicating that the winch is operating properly.		
	c) Indicator. Check that the indicator moves in the proper direction: Floating swing line indicators show a lower level as cable is wound up on the winch. Nonfloating swing line indicators show the opposite.		
C.1.3.8	**Swing Lines: External Guide System**		
	Check for leaks at threaded and flanged joints.		
C.1.3.9	**Swing Lines: Identify Ballast Varying Need**		
	Check for significant difference in stock specific gravity.		
C.1.3.10	**Swing Lines: Cable Material and Condition**		
	a) For nonstainless steel cable, check for corrosion over entire length.		
	b) All cable: check for wear or fraying.		
C.1.3.11	**Swing Lines: Product Sample Comparison**		
	Check for water or gravity differences that would indicate a leaking swing joint.		
C.1.3.12	**Swing Lines: Target**		
	Target should indicate direction of swing opening (up or down) and height above bottom where suction will be lost with swing on bottom support.		
C.1.4	**Roofs**		
C.1.4.1	**Deck Plate Internal Corrosion**		
	For safety, before accessing the roof, check with ultrasonic instrument or lightly use a ball peen hammer to test the deck plate near the edge of the roof for thinning. (Corrosion normally attacks the deck plate at the edge of a fixed roof and at the rafters in the center of the roof first.)		
C.1.4.2	**Deck Plate External Corrosion**		
	Visually inspect for paint failure, holes, pitting, and corrosion product on the roof deck.		
C.1.4.3	**Roof Deck Drainage**		
	Look for indication of standing water. (Significant sagging of fixed roof deck indicates potential rafter failure. Large standing water areas on a floating roof indicate inadequate drainage design or, if to one side, a nonlevel roof with possible leaking pontoons.)		
C.1.4.4	**Level of Floating Roof**		
	At several locations, measure distance from roof rim to a horizontal weld seam above the roof. A variance in the readings indicates a nonlevel roof with possible shell out-of-round, out-of-plumb, leaking pontoons, or hang-up. On small diameter tanks, an unlevel condition can indicate unequal loading at that level.		

Table C.1—Tank In-service Inspection Checklist (Continued)

	Item	Completed √	Comments
C.1.4.5	**Gas Test Internal Floating Roof**		
	Test for explosive gas on top of the internal floating roof. Readings could indicate a leaking roof, leaking seal system, or inadequate ventilation of the area above the internal floating roof.		
C.1.4.6	**Roof Insulation**		
	a) Visually inspect for cracks or leaks in the insulation weather coat where runoff rain water could penetrate the insulation.		
	b) Inspect for wet insulation under the weather coat.		
	c) Remove small test sections of insulation and check roof plate for corrosion and holes near areas susceptible to water ingress (i.e. roof nozzles, etc.).		
C.1.4.7	**Floating Roof Seal Systems**		
	a) Inspect the condition of the seal, measure and record maximum rim spaces and seal-to-shell gaps around the full roof circumference at the level of inspection. NOTE Inspection of the seal and measurement of the rim spaces and seal-to-shell gaps at more than one level may be necessary to more fully determine if any problems exist at other levels of tank operation).		
	b) Measure and record annular space at 30-ft spacing (minimum of four quadrants) around roof and record. Measurements should be taken in directly opposite pairs.		
	1) _______ _______ Opposite pair 1. 2) _______ _______ Opposite pair 2.		
	c) Check if seal fabric on primary shoe seals is pulling shoes away from shell (fabric not wide enough).		
	d) Inspect fabric for deterioration, holes, tears, and cracks.		
	e) Inspect visible metallic parts for corrosion and wear.		
	f) Inspect for openings in seals that would permit vapor emissions.		
	g) Inspect for protruding bolt or rivet heads against the shell.		
	h) Pull both primary and secondary seal systems back all around the shell to check their operation.		
	i) Inspect secondary seals for signs of buckling or indications that their angle with the shell is too shallow.		
	j) Inspect wedge-type wiper seals for flexibility, resilience, cracks, and tears.		
C.1.5	**Roof Appurtenances**		
C.1.5.1	**Sample Hatch**		
	a) Inspect condition and functioning of sample hatch cover.		
	b) On tanks governed by Air Quality Monitoring District rules, check for the condition of seal inside hatch cover.		
	c) Check for corrosion and plugging on thief and gauge hatch cover.		
	d) Where sample hatch is used to reel gauge stock level, check for marker and tab stating hold-off distance.		
	e) Check for reinforcing pad where sample hatch pipe penetrates the roof deck.		
	f) On floating roof sample hatch and recoil systems, inspect operation of recoil reel and condition of rope.		
	g) Test operation of system.		
	h) On ultra clean stocks such as JP4, check for presence and condition of protective coating or liner inside sample hatch (preventing rust from pipe getting into sample).		

Table C.1—Tank In-service Inspection Checklist (Continued)			
Item		Completed √	Comments
C.1.5.2	**Gauge Well**		
	a) Inspect visible portion of the gauge well for thinning, size of slots, and cover condition.		
	b) Check for a hold-off distance marker and tab with hold-off distance (legible).		
	c) On floating roofs, inspect condition of roof guide for gauge well, particularly the condition of the rollers for grooving.		
	d) If accessible, check the distance from the gauge well pipe to the tank shell at different levels.		
	e) If tank has a gauge well washer, check valve for leakage and for presence of a bull plug or blind flange.		
C.1.5.3	**Fixed Roof Scaffold Support**		
	Inspect scaffold support for corrosion, wear, and structural soundness.		
C.1.5.4	**Autogauge: Inspection Hatch and Guides (Fixed Roof)**		
	a) Check the hatch for corrosion and missing bolts.		
	b) Look for corrosion on the tape guide's and float guide's wire anchors.		
C.1.5.5	**Autogauge: Float Well Cover**		
	a) Inspect for corrosion.		
	b) Check tape cable for wear or fraying caused by rubbing on the cover.		
C.1.5.6	**Sample Hatch (Internal Floating Roof)**		
	a) Check overall conditions.		
	b) When equipped with a fabric seal, check for automatic sealing after sampling.		
	c) When equipped with a recoil reel opening device, check for proper operations.		
C.1.5.7	**Roof-mounted Vents (Internal Floating Roof)**		
	Check condition of screens, locking and pivot pins.		
C.1.5.8	**Gauging Platform Drip Ring**		
	On fixed roof tanks with drip rings under the gauging platform or sampling area, inspect for plugged drain return to the tank.		
C.1.5.9	**Emergency Roof Drains**		
	Inspect vapor plugs for emergency drain: that seal fabric discs are slightly smaller than the pipe ID and that fabric seal is above the liquid level.		
C.1.5.10	**Removable Roof Leg Racks**		
	Check for leg racks on roof.		
C.1.5.11	**Vacuum Breakers**		
	Report size, number, and type of vacuum breakers. Inspect vacuum breakers. If high legs are set, check for setting of mechanical breaker in high leg position.		
C.1.5.12	**Rim Vents**		
	a) Check condition of the screen on the rim vent cover.		
	b) Check for plating off or removal of rim vents where jurisdictional rules do not permit removal.		
C.1.5.13	**Pontoon Inspection Hatches**		
	a) Open pontoon inspection hatch covers and visually check inside for pontoon leakage.		
	b) Test for explosive gas (an indicator of vapor space leaks).		

Table C.1—Tank In-service Inspection Checklist (Continued)

	Item	Completed √	Comments
	c) If pontoon hatches are equipped with locked down coves, check for vent tubes. Check that vent tubes are not plugged up. Inspect lock-down devices for condition and operation.		
C.1.6	**Accessways**		
	See Tank Out-of-service Inspection Checklist, Item C.2.12.		

NOTES

Table C.2—Tank Out-of-service Inspection Checklist			
	Item	**Completed √**	**Comments**
C.2.1	**Overview**		
	a) Check that tank has been cleaned, is gas free, and safe for entry.		
	b) Check that the tank is completely isolated from product lines, all electrical power, and steam lines.		
	c) Check that roof is adequately supported, including fixed roof structure and floating roof legs.		
	d) Check for presence of falling object hazards, such as corroded-through roof rafters, asphalt stalactites, and trapped hydrocarbons in unopened or plugged equipment or appurtenances, ledges, etc.		
	e) Inspect for slipping hazards on the bottom and roof decks.		
	f) Inspect structural welds on accessways and clips.		
	g) Check surfaces needing inspection for a heavy-scale buildup and check weld seams and oily surfaces where welding is to be done. Note areas needing more cleaning, including blasting.		
	h) Review cathodic protection potential readings.		
C.2.2	**Tank Exterior**		
	a) Inspect appurtenances opened during cleaning such as lower floating swing sheave assemblies, nozzle interiors (after removal of valves).		
	b) Hammer test or ultrasonically test the roof.		
	c) Enter and inspect the floating roof pontoon compartments.		
C.2.3	**Bottom Interior Surface**		
	a) Using a flashlight held close to and parallel to the bottom plates, and using the bottom plate layout as a guide, visually inspect and hammer test the entire bottom.		
	b) Measure the depth of pitting and describe the pitting appearance (sharp edged, lake type, dense, scattered, etc.)		
	c) Mark areas requiring patching or further inspection.		
	d) Mark locations for turning coupons for inspection.		
	e) Inspect all welds for corrosion and leaks, particularly the shell-to-bottom weld.		
	f) Inspect sketch plates for corrosion.		
	g) Check condition of internal sump, if applicable. Standing liquid should be removed from the sump to allow for complete inspection and vacuum testing of weld seams as appropriate. Sump bottom and sidewall plate and seams need to be evaluated for both product-side and soil-side corrosion.		
	h) Locate and mark voids under the bottom.		
	i) Record bottom data on a layout sketch using the existing bottom plates as a grid. List the number and sizes of patches required.		
	j) Vacuum test the bottom lap welds.		
	k) Hammer test or ultrasonically examine any slightly discolored spots or damp areas.		
	l) Check for reinforcing pads under all bottom attached clips, brackets, and supports.		
	m) Inspect floating roof leg pads for pitting or cutting, and excessive dimpling (indicating excessive loading).		
	n) Check the column bases of fixed roof supports for adequate pads and restraining clips.		
	o) In earthquake Zones 3 and 4, check that roof supports are not welded down to the tank bottom, but are only restrained from horizontal movement.		
	p) Check area beneath swing line cable for indications of cable cutting or dragging.		
	q) Mark old oil and air test connection for removal and patching.		
	r) Identify and report low areas on the bottom that do not drain adequately.		
	s) Inspect coating for holes, disbonding, deterioration, and discoloration.		

Table C.2—Tank Out-of-service Inspection Checklist (Continued)

Item		Completed √	Comments
C.2.4	**Shell Seams and Plate**		
	a) On cone up bottoms, closely inspect and gauge the depth of metal loss on the lower 50 mm to 100 mm (2 in. to 4 in.) of the shell (area of standing water).		
	b) Measure the depth of pitting on each course.		
	c) Inspect and estimate the amount of metal loss on the heads of rivets and bolts.		
	d) Inspect shell-to-bottom riveted lap joints.		
	e) Inspect for vertical grooving damage from seal assembly protrusions.		
	f) Inspect existing protective coatings for damage, deterioration, and disbonding.		
	g) Check for areas of rubbing (indicating too much pressure by the seal assembly shoes or inadequate annular space).		
	h) Visually inspect the shell plates and seams for indications of leakage.		
	i) If the shell has riveted or bolted seams, record the leak locations by film or chart in case the locations are lost during surface preparation for painting.		
	j) Measure annular space at 12 m (40 ft) intervals.		
	k) Survey the shell to check for roundness and plumb.		
C.2.5	**Shell-mounted Overflows**		
	a) Inspect overflow for corrosion and adequate screening.		
	b) Check location of overflow that it is not above any tank valves or equipment.		
C.2.6	**Roof Interior Surface**		
C.2.6.1	**General**		
	a) Visually inspect the underside surface of the roof plates for holes, scale buildup, and pitting.		
	b) Hammer test or ultrasonically examine to check for thin areas, particularly in the vapor space of floating roofs and at edge of roof on cone roof tank.		
	c) Check all clips, brackets, braces, etc., welded to the roof deck plate for welded reinforcing pads and see that they have not broken free.		
	d) If no pad is present, penetrant test for cracking of the weld or deck plate.		
	e) Inspect for protective coating for breaks, disbondment, and deterioration.		
	f) Spark test the interior surface coating if recoating is not planned.		
C.2.6.2	**Fixed Roof Support Structure**		
	a) Inspect the support columns for thinning in the upper 600 mm (2 ft).		
	b) On API columns (two channels welded together) check for corrosion scale breaking the tack welds, unless the joint between the channels is completely seal welded.		
	c) Check that the reinforcing pad on the bottom is seal welded to the tank bottom with horizontal movement restraining clips welded to the pad.		
	d) Determine if pipe column supports are concrete filled or open pipe. If open pipe, check for a drain opening in the bottom of the pipe.		
	e) Inspect and gauge rafters for thinning, particularly near the center of the roof. Report metal loss.		
	f) Check for loose or twisted rafters.		
	g) Inspect girders for thinning and check that they are attached securely to the top of the columns.		

Table C.2—Tank Out-of-service Inspection Checklist (Continued)			
	Item	Completed √	Comments
	h) Report if the columns have cross bracing in the area between the low pump out of the top of the shell (for future internal floating roof installation).		
	i) Inspect and report presence of any roof-mounted swing line bumpers.		
	j) Photograph the roof structure if no rafter layout drawing exists.		
C.2.7	**Fixed Roof Appurtenances**		
C.2.7.1	**Inspection and Light Hatches**		
	a) Inspect the hatches for corrosion, paint and coating failures, holes, and cover sealing.		
	b) On loose covers, check for a safety chain in good condition.		
	c) On light hatches over 750 mm (30 in.) across, check for safety rods.		
	d) Inspect the condition of the gaskets on bold or latched down hatch covers.		
C.2.7.2	**Staging Support Connection**		
	Inspect the condition of the staging support for corrosion.		
C.2.7.3	**Breathers and Vents**		
	a) Inspect and service the breather.		
	b) Inspect screens on vents and breathers.		
C.2.7.4	**Emergency P/V Hatches**		
	a) Inspect and service pressure/vacuum hatches. (Setting should be high enough to prevent chattering of breather during normal operation. See breather manufacturer's guide.)		
	b) Inspect liquid seal hatches for corrosion and proper liquid level in the seal.		
C.2.7.5	**Sample Hatch**		
	a) Inspect sample hatch for corrosion.		
	b) Check that the cover operates properly.		
	c) If the tank has no gauge well, check for a hold-off distance marker and check measurement.		
C.2.8	**Floating Roof**		
C.2.8.1	**Roof Deck**		
	a) Hammer test the area between roof rim and shell. (If access for hammer testing is inadequate, measure the distance from the bottom edge of the roof to the corroded area and then hammer test from inside the pontoon.)		
	b) In sour water service, clean and test all deck plate weld seams for cracking unless the lower laps have been seal welded.		
	c) Check that either the roof drain is open or the drain plug in the roof is open in case of unexpected rain.		
	d) On flat bottomed and cone bottom roof decks, check for a vapor dam around the periphery of the roof. The dam should be continuous without break to prevent escape of vapors to the seal area from under the center of the roof.		
C.2.8.2	**Floating Roof Pontoons**		
	a) Visually inspect each pontoon for liquid leakage.		
	b) Run a light wire through the gooseneck vents on locked down inspection hatch covers to make sure they are open.		
	c) Inspect lockdown latches on each cover.		

Table C.2—Tank Out-of-service Inspection Checklist (Continued)

Item		Completed √	Comments
	d) Check and report if each pontoon is:		
	1) vapor tight (bulkhead seal welded on one side on bottom, sides, and top),		
	2) liquid tight (seal welded on bottom and sides only), or		
	3) unacceptable (minimum acceptable condition is liquid tight).		
C.2.8.3	**Floating Roof Cutouts**		
	a) Inspect underside of cutouts for mechanical damage.		
	b) Inspect welds for cracks.		
	c) Inspect plate for thinning, pitting, and erosion.		
	d) Measure mixer cutouts and record plate thickness for future mixer installation or replacement. Plate thickness ______ .		
C.2.8.4	**Floating Roof Supports**		
	a) Inspect fixed low and removable high floating roof legs for thinning.		
	b) Inspect for notching at bottom of legs for drainage.		
	c) Inspect for leg buckling or felling at bottom.		
	d) Inspect pin hole in roof guide for tears.		
	e) Check plumb of all legs.		
	f) Inspect for adequate reinforcing gussets on all legs through a single portion of the roof.		
	g) Inspect the area around the roof legs for cracking if there is no internal reinforcing pad or if the topside pad is not welded to the deck plate on the underside.		
	h) Inspect the sealing system on the two-position legs and the vapor plugs in the fixed low leg for deterioration of the gaskets.		
	i) On shell-mounted roof supports, check for adequate clearance based on the maximum floating roof movement as determined by the position of the roof relative to the gauge well and/or counter-rotational device.		
C.2.9	**Floating Roof Seal Assemblies**		
C.2.9.1	**Primary Shoe Assembly**		
	a) Remove four sections of foam log (foam-filled seals) for inspection on 90° locations.		
	b) Inspect hanger attachment to roof rim for thinning, bending, broken welds, and wear of pin holes.		
	c) Inspect clips welded to roof rim for thinning.		
	d) Shoes—inspect for thinning and holes in shoes.		
	e) Inspect for bit-metal bolts, clips, and attachments.		
	f) Seal fabric—inspect for deterioration, stiffening, holes, and tears in fabric.		
	g) Measure length of fabric from top of shoe to roof rim, and check against maximum anticipated annular space as roof operates.		
	h) Inspect any modification of shoes over shell nozzles, mixers, etc., for clearance.		
	i) Inspect shoes for damage caused by striking shell nozzles, mixers, etc.		
C.2.9.2	**Primary Toroidal Assembly**		
	a) Inspect seal fabric for wear, deterioration, holes, and tears.		

Table C.2—Tank Out-of-service Inspection Checklist (Continued)

Item		Completed √	Comments
	b) Inspect hold-down system for buckling or bending.		
	c) Inspect foam for liquid absorption and deterioration.		
C.2.9.3	**Rim-mounted Secondaries**		
	a) Inspect the rim-mounted bolting bar for corrosion and broken welds.		
	b) Measure and chart seal-to-shell gaps.		
	c) Visually inspect seam from below, looking for holes as evidenced by light.		
	d) Inspect fabric for deterioration and stiffness.		
	e) Inspect for mechanical damage, corrosion, and wear on tip in contact with shell.		
	f) Inspect for contact with obstructions above top of shell.		
C.2.10	**Floating Roof Appurtenances**		
C.2.10.1	**Roof Manways**		
	a) Inspect walls of manways for pitting and thinning.		
	b) On tanks with interface autogauges, check seal around gauge tape cable and guide wires through manway cover.		
	c) Inspect cover gasket and bolts.		
C.2.10.2	**Rim Vent**		
	a) Check rim vent for pitting and holes.		
	b) Check vent for condition of screen.		
	c) On floating roof tanks where the environmental rules require closing off the vent, check the vent pipe for corrosion at the pipe-to-rim joint and check that the blinding is adequate.		
C.2.10.3	**Vacuum Breaker, Breather Type**		
	a) Service and check operation of breather valve.		
	b) Check that nozzle pipe projects no more than $^1/_2$ in. below roof deck.		
C.2.10.4	**Vacuum Breaker, Mechanical Type**		
	Inspect the stem for thinning. Measure how far the vacuum breaker cover is raised off the pipe when the roof is resting on high or low legs.		
	a) On high legs: _________ .		
	b) On low legs: _________ .		
C.2.10.5	**Roof Drains: Open Systems, Including Emergency Drains**		
	a) Check liquid level inside open roof drains for adequate freeboard. Report if there is insufficient distance between liquid level and top of drain.		
	b) If tank comes under Air Quality Monitoring District rules, inspect the roof drain vapor plug.		
	c) If emergency drain is not at the center of the roof, check that there are at least three emergency drains.		
C.2.10.6	**Closed Drain Systems: Drain Basins**		
	a) Inspect for thinning and pitting.		
	b) Inspect protective coating (topside).		
	c) Inspect basin cover or screen for corrosion.		
	d) Test operation of check valve.		

Table C.2—Tank Out-of-service Inspection Checklist (Continued)		
Item	**Completed √**	**Comments**
e) Check for presence of check valve where bottom of basin is below product level.		
f) Inspect drain basin(s) to roof deck welds for cracking.		
g) Check drain basin(s) outlet pipe for adequate reinforcement to roof deck (including reinforcing pad).		
C.2.10.7 Closed Drain Systems: Fixed Drain Line on Tank Bottom		
a) Hammer test fixed drain line on tank bottom for thinning and scale/debris plugging.		
b) Inspect supports and reinforcing pads for weld failures and corrosion.		
c) Check that pipe is guided, not rigidly locked to support, to avoid tearing of tank bottom plate.		
C.2.10.8 Closed Drain Systems: Flexible Pipe Drain		
a) Inspect for damage to exterior of pipe.		
b) Check for obstructions that pipe could catch on.		
c) Inspect shields to protect pipe from snagging.		
d) Inspect results of hydrostatic test on flexible roof drain system.		
C.2.10.9 Closed Drain Systems: Articulated Joint Drain		
a) Hammer test rigid pipe in flexible joint systems for thinning and scale/debris plugging.		
b) Inspect system for signs of bending or strain.		
c) Inspect results of system hydrostatic test.		
d) Inspect landing leg and pad.		
C.2.10.10 Autogauge System and Alarms		
a) Check freedom of movement of tape through autogauge tape guide.		
b) Inspect sheaves for freedom of movement.		
c) Test operation checker.		
d) Inspect tape and tape cable for twisting and fraying.		
e) Test the tape's freedom of movement through guide sheaves and tape guide pipe.		
f) On open-top tanks, check that gate tapes with cables have no more than one foot of tape exposed with float at lowest point.		
g) Check float for leakage.		
h) Test float guide wire anchors for spring action by pulling on wire and releasing.		
i) Inspect floatwells in floating roofs for thinning and pitting of walls just above the liquid level.		
j) Check that the autogauge tape is firmly attached to the float.		
k) Inspect the tape cable and float guide wire fabric seals through the float well cover.		
l) Inspect the bottom guide wire attachment clip: inspect for a temporary weighted bar instead of a permanent welded down clip.		
m) Inspect board-type autogauge indicators for legibility and freedom of movement of indicator.		
n) Measure and record these distances to determine if seal damage will occur if tank is run over from:		
1) Shell top angle to underside of tape guide system.		
2) Liquid level on floating top to top of secondary seal.		

Table C.2—Tank Out-of-service Inspection Checklist (Continued)

	Item	Completed √	Comments
	o) Identify floating roofs where the tape is connected directly to the roof.		
	p) Overfill alarm: Inspect tank overfill prevention alarm switches for proper operation.		
C.2.11	**Common Tank Appurtenances**		
C.2.11.1	**Gauge Well**		
	a) Inspect gate well pipe for thinning at about two-thirds distance above the bottom: look for thinning at the edge of the slots.		
	b) Check for corrosion on the pipe joint. Check that sample cords, weights, thermometers, etc., have been removed from the pipe.		
	c) Check for cone at bottom end of pipe about one foot above the bottom.		
	d) Check condition of well washer pipe and that its flared end is directed at the near side of the hold off pad.		
	e) Check that supports for gauge well are welded to pad or to shell and not directly to bottom plate.		
	f) Check operation of gauge well cover.		
	g) Check presence of a hold-off distance marker in well pipe and record hold-off distance. Hold-off distance __________ .		
	h) Identify and report size and pipe schedule, and whether pipe is solid or slotted. Report slot size.		
	i) Check that the hold-off distance plate is seal welded to the bottom and that any gauge well supports are welded to the plate and not directly to the bottom.		
	j) Inspect vapor control float and cable.		
	k) Check for presence and condition of gauge well washer.		
	l) Check for bull plug or plate blind on gauge well washer valve.		
	m) Inspect gauge well guide in floating roof for pitting and thinning.		
	n) Inspect the guide rollers and sliding plates for freedom of movement.		
	o) Inspect condition of gauge well pipe seal system.		
	p) On black oil and diesel services: if gauge well is also used for sampling, check for presence of a thief- and gauge-type hatch to avoid spillage.		
	q) Visually inspect inside of pipe for pipe weld protrusions which could catch or damage vapor control float.		
C.2.11.2	**Sampling Systems: Roof Sample Hatches**		
	a) Inspect roof-mounted sample hatches for reinforcing pads and cracking.		
	b) Inspect cover for operation.		
	c) For tanks complying with Air Quality Monitoring District rules, inspect sample hatch covers for adequate sealing.		
	d) Check horizontal alignment of internal floating roof sample hatches under fixed roof hatches.		
	e) Inspect the sealing system on the internal floating roof sample hatch cover.		
	f) Inspect floating roof sample hatch cover recoil reel and rope.		
C.2.11.3	**Shell Nozzles**		
	a) Inspect shell nozzles for thinning and pitting.		
	b) Inspect hot tap nozzles for trimming of holes.		

Table C.2—Tank Out-of-service Inspection Checklist (Continued)			
	Item	**Completed √**	**Comments**
	c) Identify type of shell nozzles.		
	d) Identify and describe internal piping, including elbow-up and elbow-down types.		
C.2.11.4	**For Nozzles Extended Into the Tank**		
	a) Inspect pipe support pads welded to tank bottom.		
	b) Inspect to see that pipe is free to move along support without strain or tearing action on bottom plate.		
	c) Inspect nozzle valves for packing leaks and damaged flange faces.		
	d) Inspect heater stream nozzle flanges and valves for wire cutting.		
	e) Report which nozzles have thermal pressure relief bosses and valves.		
	f) In internal elbow-down fill line nozzles, inspect the wear plate on the tank bottom.		
	g) On elbow-up fill lines in floating roof tanks, check that opening is directed against underside of roof, not against vapor space. Inspect impact are for erosion.		
C.2.11.5	**Diffusers and Air Rolling Systems**		
	a) Inspect diffuser pipe for erosion and thinning.		
	b) Check holes in diffuser for excessive wear and enlargement.		
	c) Inspect diffuser supports for damage and corrosion.		
	d) Check that diffuser supports restrain, not anchor, longitudinal line movement.		
	e) Inspect air spiders on bottom of lube oil tanks for plugging and damaged or broken threaded joints.		
C.2.11.6	**Swing Lines**		
	a) Inspect flexible joint for cracks and leaks.		
	b) Scribe the flexible joint across the two moving faces and raise end of swing line to check the joint's freedom of movement, indicated by separation of scribe marks.		
	c) Check that flexible joints over 150 mm (6 in.) are supported.		
	d) Inspect the swing pipe for deep pitting and weld corrosion.		
	e) Loosen the vent plugs in the pontoons and listen for a vacuum. Lack of a vacuum indicates a leaking pontoon.		
	f) Check the results of air test on pontoons during repairs.		
	g) Inspect the pontoons for pitting.		
	h) Inspect the pull-down cable connections to the swing.		
	i) Inspect the condition of the bottom-mounted support, fixed roof limiting bumper, or shell-mounted limiting bumper for wood condition, weld and bolt corrosion, and seal welding to bottom or shell.		
	j) Inspect safety hold-down chain for corrosion and weak links.		
	k) Check that there is a welded reinforcing pad where the chain connects to the bottom.		
	l) If the floating swing in a floating or internal floating roof tank does not have a limiting device preventing the swing from exceeding 60 degrees, measure and calculate the maximum angle possible with the roof on overflow. Max. angle on overflow _____________ . (If the calculated angle exceeds 65 degrees, recommended installation of a limiting bracket.)		
	m) Inspect pull-down cable for fraying.		

Table C.2—Tank Out-of-service Inspection Checklist (Continued)			
	Item	Completed √	Comments
	n) Inspect for three cable clamps where cable attaches to end of swing line (single-reeved) or to roof assembly (double-reeved). Inspect sheaves for freedom of movement.		
	o.) Inspect winch operation and check the height indicator for legibility and accuracy.		
	p) Inspect bottom-mounted sheave assembly at end of pontoon for freedom of rotation of sheave.		
	q) Inspect shell-mounted lower sheave assembly for freedom of rotation of sheave, corrosion thinning, and pitting of sheave housing.		
	r) Inspect upper sheave assembly for freedom of movement of sheave.		
	s) Inspect the cable counterbalance assembly for corrosion and freedom of operation.		
C.2.11.7	**Manway Heater Racks**		
	a) Inspect the manway heater racks for broken welds and bending of the sliding rails.		
	b) Measure and record the length of the heater and length of the track.		
C.2.11.8	**Mixer Wear Plates and Deflector Stands**		
	a) Inspect bottom and shell plates and deflector stands.		
	b) Inspect for erosion and corrosion on the wear plates. Inspect for rigidity, structural soundness, corrosion, and erosion of deck plates and reinforcing pads that are seal welded to the bottom under the deflector stand legs.		
	c) Measure for propeller clearance between the bottom of deflector stand and roof when the roof is on low legs.		
C.2.12	**Access Structures**		
C.2.12.1	**Handrails**		
	a) Identify and report type (steel pipe, galvanized pipe, square tube, angle) and size of handrails.		
	b) Inspect for pitting and holes, paint failure.		
	c) Inspect attachment welds.		
	d) Identify cold joints and sharp edges. Inspect the handrails and midrails.		
	e) Inspect safety drop bar (or safety chain) for corrosion, functioning, and length.		
	f) Inspect the handrail between the rolling ladder and the gaging platform for a hazardous opening when the floating roof is at its lowest level.		
C.2.12.2	**Platform Frame**		
	a) Inspect frame for corrosion and paint failure.		
	b) Inspect the attachment of frame to supports and supports to tank for corrosion and weld failure.		
	c) Check reinforcing pads where supports are attached to shell or roof.		
	d) Inspect the surface that deck plate or grating rests on, for thinning and holes.		
	e) Check that flat-surface-to-flat-surface junctures are seal welded.		
C.2.12.3	**Deck Plate and Grating**		
	a) Inspect deck plate for corrosion-caused thinning or holes (not drain holes) and paint failure.		
	b) Inspect plate-to-frame weld for rust scale buildup.		
	c) Inspect grating for corrosion-caused thinning of bars and failure of welds.		

Table C.2—Tank Out-of-service Inspection Checklist (Continued)		
Item	**Completed √**	**Comments**
d) Check grating tie down clips. Where grating has been retrofitted to replace plate, measure the rise of the step below and above the grating surface and compare with other risers on the stairway.		
C.2.12.4 Stairway Stringers		
a) Inspect spiral stairway stringers for corrosion, paint failure, and weld failure. Inspect attachment of stairway treads to stringer.		
b) Inspect stairway supports to shell welds and reinforcing pads.		
c) Inspect steel support attachment to concrete base for corrosion.		
C.2.12.5 Rolling Ladder		
a) Inspect rolling ladder stringers for corrosion.		
b) Identify and inspect ladder fixed rungs (square bar, round bar, angles) for weld attachment to stringers and corrosion, particularly where angle rungs are welded to stringers.		
c) Check for wear and corrosion where rolling ladder attaches to gaging platform.		
d) Inspect pivot bar for wear and secureness.		
e) Inspect operation of self-leveling stairway treads.		
f) Inspect for corrosion and wear on moving parts.		
g) Inspect rolling ladder wheels for freedom of movement, flat spots, and wear on axle.		
h) Inspect alignment of rolling ladder with roof rack.		
i) Inspect top surface of rolling ladder track for wear by wheels to assure at least 18 in. of unworn track (track long enough).		
j) Inspect rolling ladder track welds for corrosion.		
k) Inspect track supports on roof for reinforcing pads seal welded to deck plate.		
l) Check by dimensioning, the maximum angle of the rolling ladder when the roof is on low legs. Max. angle ____________ .		
m) If rolling ladder track extends to within 5 ft of the edge of the roof on the far side, check for a handrail on the top of the shell on that side.		
NOTES		

Annex D
(normative)

Authorized Inspector Certification

D.1 Examination

A written examination to certify an authorized inspector within the scope of API 653 shall be based on the current API 653 inspector certification body of knowledge (BOK) as published by API.

D.2 Certification

D.2.1 An API 653 authorized inspector certificate will be issued when an applicant has successfully passed the API 653 certification exam, and satisfies the criteria for experience and education. To qualify for the certification examination, the applicant's education and experience, when combined, shall be equal to at least one of the following four table rows in Table D.1.

Table D.1—Certification Qualification Requirements

Education	Years of Industry Experience	Experience Required
BS degree or higher in engineering or technology or 3+ years of military service in a technical role (*Dishonorable discharge disqualifies credit*)	1 year	Supervision or performance of inspection activities as described in API 653
2-year degree or certificate in engineering or technology or 2 years of military service in a technical role (*Dishonorable discharge disqualifies credit*)	2 years	Design, fabrication, repair, operation, or inspection of aboveground storage tanks, of which one year must be in supervision or performance of inspection activities as described in API 653
High school diploma or equivalent	3 years	Design, fabrication, repair, operation, or inspection of aboveground storage tanks, of which one year must be in supervision or performance of inspection activities as described in API 653
No formal education	5 or more years	Design, fabrication, repair, operation, or inspection of aboveground storage tanks, of which one year must be in supervision or performance of inspection activities as described in API 653

D.2.2 An API certificate for an authorized inspector is valid for three years from its date of issuance.

D.2.3 An API 653 authorized inspector certificate is valid in all jurisdictions and any other location that accepts or otherwise does not prohibit the use of API 653.

D.3 Certification Agency

API shall be the certifying agency.

D.4 Recertification

D.4.1 Recertification is required three years from the date of issuance of the API 653 authorized inspector certification. Inspectors who are recertifying shall meet all recertification requirements as defined below. Recertification by written examination will be required for authorized inspectors who have not been actively engaged as authorized inspectors within the most recent three-year certification period or fail to meet the recertification requirements prior to the end of their expiration grace period. Recertification exams will be in accordance with all the provisions contained in API 653.

D.4.2 Actively engaged as an authorized inspector shall be defined as one of the following provisions:

a) a minimum of 20 % of the time spent performing inspection activities, or supervision of inspection activities, or engineering support of inspection activities as described in API 653 over the most recent three-year certification period;

b) performance of inspection activities or supervision of inspection activities or engineering support of inspection activities on 75 aboveground storage tanks as described in API 653 over the most recent three-year certification period

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

D.4.3 Beginning January 1, 2022, ICP will include Continuing Professional Development (CPD) hours in its 3-year recertification requirements for API 653. ICP will have a phased implementation of the CPD hour requirement beginning with 8 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.

D.4.4 Every other recertification period (every six years), actively engaged inspectors shall demonstrate knowledge of revisions to API 653 as well as other relevant API documents that encompass the body of knowledge (BOK). These documents are identified in the relevant Web Quiz Publication Effectivity sheet and 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 E

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Annex F
(normative)

NDE Requirements Summary

Table F.1—NDE Requirements Summary

Process	Welds Requiring Inspecting	Reference Section
VE	Cavities from removal of repads.	API 653, 12.1.2.2
VE	Completed welds of stress-relieved assemblies after stress relief but before hydrostatic testing.	API 653, 12.1.2.4
VE	All fillet welds and completed repairs of fillet welds.	API 650, 7.3.2.2 and API 653, 12.1.3.3
VE	Completed welds of new permanent attachments and areas of removed temporary attachments.	API 653, 12.1.4.2
VE	New shell-plate-to-shell-plate welds.	API 653, 12.1.5
VE	Tack welds left in place.	API 650, 7.2.1.8
VE	Bottom plate and all welds, including the weld attaching a patch plate to the bottom, for new bottom plates.	API 653, 12.1.7.1
VE	Root and final weld pass of patch plate to bottom in the critical zone.	API 653, 12.1.7.2
VE	Areas of a bottom plate repaired by welding.	API 653,12.1.7.3
VE	Areas of a shell plate to be repaired by welding.	API 653, 12.1.8.1
VE	Cavities from removal of weld defects.	API 653, 12.1.3.1
VE	Friction stud welds	API 653, 12.1.11
VE	Annular plate butt welds, root pass and final pass.	API 653, 12.3.3.4.b
VE	Repaired areas of the shell-to-bottom weld.	API 653, 12.3.3.5.2
MT or PT	Cavities from removing existing reinforcing pad welds.	API 653, 12.1.2.2
MT or PT	New welds of nozzle neck-to-shell, nozzle neck-to-repad, and repad-to-shell.	API 653, 12.1.2.3
MT or PT	Completed welds of stress-relieved assemblies after stress relief, before hydrostatic testing.	API 653, 12.1.2.4
MT or PT	Cavities from removal of weld defects.	API 653, 12.1.3.1
MT or PT	For API 650 Group IV, IVA, V, and VI materials: Completed welds of new permanent attachments and areas of removed temporary attachments on API 650 material Groups IV, IVA, V, or VI (or at the approval of the purchaser, by liquid penetrant method)	API 653, 12.1.4.2
MT or PT	The back-gouged surface of the root pass and the final surface of new shell plate welds where the shell is thicker than 25 mm (1 in.)	API 653, 12.1.5.1
MT or PT	Existing shell-to-bottom welds that will be under a patch plate, plus 150 mm (6 in.) on each side.	API 653, 12.1.6.3
MT or PT	Root and final weld pass of patch plate to bottom in the critical zone.	API 653, 12.1.7.2
MT or PT	Bottom plate restored by welding.	API 653, 12.1.7.3
MT or PT	Areas of a shell plate repaired by welding.	API 653, 12.1.8.1
MT or PT	MT or PT repairs to the annular plate or bottom plates within the critical zone after root and final pass.	API 653, 12.3.3.4.b
MT or PT	MT or PT repairs to the shell-to-bottom welds before and after the root pass, and after the final pass.	API 653, 12.3.3.5.2

Table F.1—NDE Requirements Summary (Continued)

Process	Welds Requiring Inspecting	Reference Section
MT or PT	The back-gouged surface of the root pass of full penetration nozzle neck-to-shell and repad welds as required by API 653, 12.3.3.3.5, specific hydrostatic test exemption requirement.	API 653, 12.3.3.3.5
MT	Magnetic particle examination alone is required for arc gouged weld removal areas of the bottom-to-shell welds when removing a bottom.	API 653, 9.11.2.3
MT	The magnetic particle examination acceptance standard is ASME Section V, Article 7.	API 650, 8.2.1
PT	The liquid penetrant examination acceptance standards are ASME Section V, Article 6.	API 650, 8.4.1
TT	Friction stud welds	API 653, 12.1.11
UT	Shell areas over which lap patch plates are to be welded.	API 653, 9.3.1.9
UT	Shell areas over which new reinforcing or hot tap nozzles are to be welded.	API 653, 12.1.2.1
UT	Completed repairs of butt welds, unless radiographed.	API 653, 12.1.3.2
UT	The full penetration nozzle neck-to-shell and repad welds are required by API 653, 12.3.3.3.6, specific hydrostatic test exemption requirement.	API 653, 12.3.3.3.6
UT	Repairs to annular plate butt welds after final pass.	API 653, 12.3.3.4.b
VB	New shell-to-bottom welds, unless diesel tested.	API 653, 12.1.6
VB	New bottom welds, unless tracer gas tested.	API 653, 12.1.7.3
VB	New roof plate welds for tanks designed to be gas tight.	API 650, 7.3.7
VB	Potential bottom plate leak paths.	API 653, 12.1.7.1
VB	Patch plates welded on the bottom.	API 653, 12.1.7.1 and 12.1.7.2
VB	Bottom plate restored by welding.	API 653, 12.1.7.3
Tracer-Gas	Required for new bottom welds, unless vacuum box tested.	API 653, 12.1.7
Pen. Oil	The first pass of new shell-to-bottom welds and the final new shell-to-bottom weld, unless the final weld is vacuum box tested.	API 653, 12.1.6
Pen. Oil	Floating roof deck seams and other joints required to be liquid tight or vapor tight.	API 650, H.6.2 and C.4.2
Air Test	Repad-to-shell, repad-to-nozzle, and nozzle-to-shell welds of new or altered shell nozzles.	API 650, 7.3.4
Air Test	Initial pass of the shell-to-bottom welds and inside and outside of the shell, if the weld is not tested by vacuum box or penetrating oil.	API 653, 12.1.6.2
RT	Butt welds for insert plates and thickened insert plates containing penetration(s) shall be fully radiographed.	API 653, 12.2.1.8
RT	Weld repairs to butt welds, unless ultrasonically examined.	API 653, 12.1.3.2
RT	Vertical and horizontal joints and junctions of new shell plates welded to new shell plates and new plates welded to existing plates. This section covers shell replacement plates and door sheets.	API 653, 12.2
RT	Tank shell butt welds on reconstructed tanks.	API 653, 12.2.1.5
RT	New annular plate joints.	API 650, 8.1.2.9
RT	Vertical and horizontal shell joints, as required by API 653, 12.3.3.3.5, specific hydrostatic test exemption requirements.	API 653, 12.3.3.3.5

Definitions:

MT = Magnetic Particle

Pen Oil = Penetrating Oil Testing

PT = Liquid Penetrant Examination

RT = Radiographic Examination

TT = Torque Test

UT = Ultrasonic Examination

VB = Vacuum Box Testing

VE = Visual Examination

Acceptance Standards:

Air Test: None

Pen Oil: None

MTPT: ASME Section VIII, Appendix 8 (paragraphs 8-3, 8-4, 8-5)

RT: ASME Section VIII (paragraph UW-51(b))

Tracer Gas: None

UE: API 650, Section 8.3.2.5

VB: None

VE: API 650, Section 8.5.1

Examiner Qualifications:

Air Test: None

Pen Oil: None

MTPT: API 650, Section 8.2.3

RT: ASNT SNT-TC-1A Level II or III. Level I personnel may be used under the supervision of Level II or Level III personnel with a written procedure in accordance with ASME Section V, Article 2.

Tracer Gas: None

UE: ASNT SNT-TC-1A Level II or III. Level I personnel may be used under the supervision of Level II or Level III personnel with a written procedure in accordance with ASME Section V, Article 2.

VB: API 650, Section 8.6.4

VE: API 650, Section 8.5.1

Procedure Requirements:

Air Test: API 650, Section 7.3.5

Pen Oil: None

MTPT: ASME Section V

RE: ASME Section V, Article 2

Tracer Gas: API 650, Section 8.6.11

UE: ASME Section V

VB: API 650, Section 8.6

VE: None

Annex G
(informative)

Qualification of Tank Bottom Examination Procedures and Personnel

G.1 Introduction

G.1.1 This annex provides guidance for qualifying both tank bottom examination procedures and individuals that perform tank bottom examinations. Owner/operators may elect to either apply this annex as written or modify it to meet their own applications and needs. Tank bottom examinations are an important factor in providing the owner/operator increased assurance of tank integrity. As a result, it is important that qualified examination procedures and personnel are used in these examinations. Specific agreements and requirements for qualification of tank bottom examination procedures and tank bottom examiners should be established between the owner/operator and the authorized inspection agency.

G.1.2 There have been many NDE tools developed for examining tank bottoms. Most of these tools are complex and require the operator to have a high level of knowledge and skill. The effectiveness of these examinations may vary greatly depending on the equipment used, the examination procedure, and the skill of the examiner.

Often the owner/operator will not have the ability to easily determine if the tank bottom examination has been effective in assessing the actual condition of the tank bottom. The requirements in this annex will provide the owner/operator additional assurance that the tank bottom examination will find significant metal loss.

G.2 Definitions

G.2.1
authorized inspection agency
Organizations that employ an aboveground storage tank inspector certified by API (see 3.3).

G.2.2
bottom scan
The use of equipment over large portions of the tank bottom to detect corrosion in a tank bottom. One common type of bottom-scanning equipment is the magnetic flux leakage (MFL) scanner.

G.2.3
essential variables
Variables in the procedure that cannot be changed without the procedure and scanning operators being re-qualified.

G.2.4
examiners
Scanning operators and NDE technicians who prove-up bottom indications.

G.2.5
non-essential variables
Variables in the procedure that can be changed without having to re-qualify the procedure and/or scanning operators.

G.2.6
qualification test
The demonstration test that is used to prove that a procedure or examiner can successfully find and prove-up tank bottom metal loss.

G.2.7
scanning operator
operator
The individual that operates bottom-scanning equipment.

G.2.8
sizing
prove-up
The activity that is used to accurately determine the remaining bottom thickness in areas where indications are found by the bottom scanning equipment. This is often accomplished using the UT method.

G.2.9
tank bottom examination
The examination of a tank bottom using special equipment to determine the remaining thickness of the tank bottom. It includes both the detection and prove-up of the indications. It does not include the visual examination that is included in the internal inspection.

G.2.10
tank bottom examination procedure
TBP
A qualified written procedure that addresses the essential and non-essential variables for the tank bottom examination. The procedure can include multiple methods and tools, i.e. bottom scanner, hand scanner, and UT prove-up.

G.2.11
tank bottom examiner qualification record
TBEQ
A record of the qualification test for a specific scanning operator. This record must contain the data for all essential variables and the results of the qualification test.

G.2.12
tank bottom procedure qualification record
TBPQ
A record of the qualification test for a tank bottom examination procedure. This record must contain the data for all essential variables and the results of the qualification test.

G.2.13
variables or procedure variables
The specific data in a procedure that provides direction and limitations to the scanning operator. Examples include: plate thickness, overlap of adjacent bottom scans, scanning speed, equipment settings, etc.

G.3 Tank Bottom Examination Procedures

G.3.1 Each authorized inspection agency performing tank bottom examinations is responsible to have and use TBPs. These procedures provide direction for examiners performing tank bottom examinations. A procedure also allows the owner/operator or authorized inspector to verify whether the examiners are correctly performing the examinations.

G.3.2 The authorized inspection agency that performs the tank bottom examinations should develop the TBPs.

G.3.3 Each TBP shall address essential and non-essential variables. Section G.5.3 provides guidance for determining appropriate TBP essential and non-essential variables. Each procedure should specify limits on appropriate variables, e.g. plate thickness range.

G.4 Tank Bottom Examiners

G.4.1 Examiners need only to be qualified for the work they do in the field. For example, scanning operators who only use the bottom scanning equipment and do not prove-up the flaw with a follow-up method need only to be qualified for the scanning operation.

G.4.2 The purpose of qualifying the tank bottom examiner is to determine if the examiner is capable of satisfactorily using a qualified procedure to determine the condition of the tank bottom.

G.4.3 Each authorized inspection agency is responsible to train, test and qualify the scanning operators and examiners they employ using follow-up techniques. Qualifications gained through one authorized inspection agency are not necessarily valid for any other authorized inspection agency [see G.4.4 and G.4.9 f)].

G.4.4 The authorized inspection agency is responsible for training each scanning operator they employ. Each scanning operator should receive a minimum of 40 hours of training. This training should include:

a) instruction on the NDE principles/methods used by the bottom scanner, limitations and application of the specific scanning equipment and procedure, scanning equipment calibration and operation, key scanning equipment operating variables, etc.;

b) hands-on operation of the bottom scanner under the direct supervision of a qualified scanning examiner.

When hiring experienced examiners, the authorized inspection agency should verify and document previous examiner training and provide any additional training, if necessary. Experienced examiners should be provided training regarding specific procedural requirements and test equipment to be utilized by the new employer.

G.4.5 The authorized inspection agency is responsible for testing each scanning operator by written examination. The test questions should be appropriate for the scanning method to be used. The authorized inspection agency should establish the passing score for the written examination.

G.4.6 The authorized inspection agency is responsible for qualifying all examiners they employ. All examiners (scanning operators and examiners performing prove-up on the indications) shall be qualified by performing an examination on test plates as specified in G.5. Only third-party companies, having no conflict of interest in tank bottom examination applications, or owner/operator companies may facilitate qualification tests. The examiner shall be considered qualified if the acceptance criteria specified in G.5.3 has been met.

Examiners performing prove-up of indications using ultrasonic testing methods should be qualified in accordance with API 650, Section 8.3.2 and supplemental requirements given in this annex.

G.4.7 During the qualification test, a TBEQ must be completed for each examiner. The TBEQ is a record of the variables used during the qualification test. On the TBEQ, the qualifying company must record:

a) the essential variables from the qualification test;

b) the qualification test results;

c) number of hours the individual has been trained;

d) test score from the written training examination.

The TBEQ shall be certified (signed) as accurate by a representative of the authorized inspection agency and a representative of the company facilitating the test.

G.4.8 The TBEQ may be written in any format that contains all the required information.

G.4.9 The bottom-scanning examiners (operators and/or UT examiners) should be re-qualified when any of the following apply:

a) when the examiner is not qualified to the TBP that is to be used at the owner/operator facility;

b) when the authorized inspection agency changes the TBP and that change requires the procedure to be re-qualified;

c) when the operator has not performed a tank bottom scan in six months;

d) when the operator has not used the specific procedure (TBP) for 12 months;

e) when the authorized inspection agency has reason to question the ability of the examiner;

f) when an examiner changes to a new employing authorized inspection agency that uses procedures with essential variables that are different from the previous employer's procedures.

G.5 Qualification Testing

G.5.1 Qualification Test Plates

G.5.1.1 The qualification test will be performed on a sample tank bottom with designed flaws. The sample tank bottom should be a minimum of 6.5 m^2 (70 ft^2) to provide space for the designed flaws. The plate material used to fabricate sample plates may be either new steel or used steel. It should be noted that the results obtained during qualification tests might not be indicative of the results of examinations performed on other plates of differing quality or permeability. When used steel is utilized for qualification purposes, the qualification test acceptance standards recommended in G.5.2 may not be appropriate. The owner/operator should establish its own acceptance standards in such cases.

G.5.1.2 The minimum number and types of underside test pits located on the test plates are described in Table G.1, below:

Table G.1a—Underside Pits, in SI Units

Remaining Bottom Thickness (*t*) (mm)	**Minimum Number of Pits**
$t < 1.27$	2
$1.27 < t < {}^1/2T$	5
${}^1/2T < t < {}^2/3T$	4

Table G.1b—Underside Pits, in USC Units

Remaining Bottom Thickness (*t*) (in.)	**Minimum Number of Pits**
$t < 0.050$	2
$0.050 < t < {}^1/2T$	5
${}^1/2T < t < {}^2/3T$	4

where

T is nominal bottom thickness;

t is the remaining bottom thickness at test plate flaws.

NOTE Test pits should generally be hemispherical having a depth-to-diameter ratio of from 20 % to 50 %. Test pits should not be flat bottom holes since examiners may interpret these as a lamination. Also, machined conical holes should not be used since they are difficult to size with UT methods.

The owner/operator may consider placing additional flaws near the plate edge, i.e. less than 150 mm (6 in.) from the edge, to determine if such flaws can be detected by authorized inspection agency procedures. Any flaws placed closer than 150 mm (6 in.) to the plate edge should be in addition to those shown above and should not be included in determining qualification unless specifically required by an owner/operator and such defects are stated as being detectable in authorized inspection agency procedures.

G.5.1.3 The minimum number and types of product side test pits located on the test plates are described in Table G.2.

Table G.2a—Product-side Pits, in SI Units

Remaining Bottom Thickness (*t*) (mm)	**Minimum Number of Pits**
$1.27 < t < {}^1/_2T$	2
${}^1/_2T < t < {}^2/_3T$	2

Table G.2b—Product-side Pits, in USC Units

Remaining Bottom Thickness (*t*) (in.)	**Minimum Number of Pits**
$0.050 < t < {}^1/_2T$	2
${}^1/_2T < t < {}^2/_3T$	2

G.5.1.4 There should also be at least one area representing general soilside corrosion. This area should be at least 6350 mm^2 (10 in.^{2}) and have a remaining bottom thickness of about ${}^1/_2T$ (nominal plate thickness).

G.5.2 Qualification Test Acceptance Standards

G.5.2.1 The following acceptance criteria must be met when qualifying either an examination procedure or an examiner. If all the acceptance criteria are met, the procedure or examiner shall be considered qualified. Owner/operators may substitute alternative acceptance criteria, either more or less conservative, based on their specific needs and requirements.

G.5.2.2 When qualifying either a procedure or a scanning operator, the operator must be able to detect the flaws identified in Table G.3 below.

G.5.2.3 When qualifying either a procedure or an examiner, who proves up the indications, the examiner must be able to determine the flaw depth as identified in Table G.4 below.

The owner/operator should determine if additional flaw dimensions must be addressed in the qualification process.

Table G.3a—Flaws Required to Qualify a Procedure or Operator, in SI Units

Remaining Bottom Thickness (*t*) (mm)	**Flaws That Must Be Found**
$t < 1.27$	90 % to 100 %
1.27 mm < $t < {}^1/_2T$	70 % to 90 %
${}^1/_2T < t < {}^2/_3T$	40 % to 60 %
Area of general corrosion	100 %

Table G.3b—Flaws Required to Qualify a Procedure or Operator, in USC Units

Remaining Bottom Thickness (*t*) (in.)	**Flaws That Must Be Found**
$t < 0.050$	90 % to 100 %
0.050 in. < $t < {}^1/_2T$	70 % to 90 %
${}^1/_2T < t < {}^2/_3T$	40 % to 60 %
Area of general corrosion	100 %

Table G.4a—Flaw Depth to Qualify a Procedure or Examiner, in SI Units

Type of Tank Bottom (mm)	**Prove-up (Flaw Depth)** (mm)
Not coated	±0.50 mm
Thin coating < .75 mm	±0.75 mm
Thick coating > .75 mm	Per agreement with owner/operator

Table G.4b—Flaw Depth to Qualify a Procedure or Examiner, in USC Units

Type of Tank Bottom (in.)	**Prove-up (Flaw Depth)** (in.)
Not coated	±0.020 in.
Thin coating < 0.030 in.	±0.030 in.
Thick coating > 0.030 in.	Per agreement with owner/operator

G.5.2.4 While false calls, also referred to as over-calls, tend to be more of an examination efficiency issue than a tank bottom integrity issue, the owner/operator should determine if they should be addressed in the qualification process.

G.5.3 Qualification Test Variables

G.5.3.1 Essential variables are those items that may have a significant effect on the quality of the examination if they are changed from those used during the qualification test.

G.5.3.2 Table G.5 lists suggested items that may be considered as essential variables for the qualification test when qualifying either a tank bottom examination procedure or a tank bottom examiner. Essential variables may be different for different types of tank bottom scanners. Authorized inspection agencies are responsible for determining what additional variables should be considered essential variables for each tank bottom scanner.

G.5.3.3 Essential variables and the values must be recorded on the TBP and on the TBEQ.

G.5.3.4 Non-essential variables are those items that will have a lesser effect on the quality of the examination. Non-essential variables may be different for different types of tank bottom scanners.

Table G.5a—Suggested Essential Variables for Qualification Tests, in SI Units

Essential Variable	Used During Test	Qualified
Scanner Equipment	As tested	Same as tested
Prove-up Equipment	As tested	Same as tested
Prove-up Procedure	As tested	Same as tested
Plate Thickness (T)	T	T + 0.13 mm – T – 3.30 mm
Coating Thickness (t_c)	No coating used	0.000 mm
	0.50 mm < t_c < 0.75 mm	0.500 mm to 0.75 mm
	0.751 mm < t_c < 2.03 mm	0.751 mm to 2.03 mm
	t_c > 2.03 mm	2.04 mm to t_c
Distance from Shell (d_s)	d_s	Lesser of 200 mm or d_s
Critical Equipment Settings	As tested	Per manufacturer
Threshold Settings (T_h)	T_h	< 10 % T_h
Calibration or Functional Check	As tested	Same as tested

Table G.5b—Suggested Essential Variables for Qualification Tests, in USC Units

Essential Variable	Used During Test	Qualified
Scanner Equipment	As tested	Same as tested
Prove-up Equipment	As tested	Same as tested
Prove-up Procedure	As tested	Same as tested
Plate Thickness (T)	T	T + 0.005 in. – T – 0.130 in.
Coating Thickness (t_c)	No coating used	0.000 in.
	0.001 in. < t_c < 0.030 in.	0.001 in. to 0.030 in.
	0.031 in. < t_c < 0.080 in.	0.031 in. to 0.080 in.
	t_c > 0.080	0.081 in. to t_c
Distance from Shell (d_s)	d_s	Lesser of 8 in. or d_s
Critical Equipment Settings	As tested	Per manufacturer
Threshold Settings (T_h)	T_h	< 10 %T_h
Calibration or Functional Check	As tested	Same as tested

G.5.3.5 Non-essential variables must be listed on the TBP but need not be addressed on the TBPQ or the TBEQ. The following is a list of examples of items that might be considered as non-essential variables. Equipment manufacturers and authorized inspection agencies are responsible to determine what addition factors should be considered non-essential variables for each tank bottom scanner:

a) scanner speed;

b) scanning pattern;

c) height limitations;

d) overlap between scans;

e) plate cleanliness;

f) non-critical equipment settings.

NOTE Some of the listed non-essential variables may actually be essential variables for specific types of scanners.

Annex H
(informative)

Similar Service Assessment

This annex is provided as guidance for performing a similar service assessment. This annex is not all inclusive and is not mandatory. It is not intended to prevent the use of other similar service assessment methods. This annex contains sample datasheets illustrating items that should be considered when conducting a similar service assessment. The datasheet format facilitates the recording of assessment findings.

NOTE 1 The following examples 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.

NOTE 2 Where applicable, authorities having jurisdiction should be consulted.

H.1 Scope

This annex provides guidance for conducting a similar service assessment to establish inspection intervals for tanks for which corrosion rates have not been directly measured as referenced in 6.3.2 and 6.4.2. This annex is intended for use by an authorized inspector, storage tank engineer and other person(s) having knowledge and experience in performing similar service assessments.

H.2 Similar Service Assessment

Several criteria must be evaluated to determine whether the candidate tank is in similar service with the control tank. Similar service assessment requires a sufficient amount of data collection and analysis and needs to be performed in a comprehensive and thorough fashion in accordance with an established risk management program. Similar service assessment is conducted using design, construction, operation, maintenance and inspection data. Data should be obtained by using direct and indirect examination procedures such as MT and UT, evaluating product corrosivity, measuring CP levels, determining soil properties, and other factors. Similar Service assessments shall use corrosion rates based on corrosion depth over time. The corrosion rates definitions for StPr and UPr of 4.4.5.1 are based on the predicted corrosion rate after repairs and mitigations, and they are not commutable from the control to candidate tanks unless the candidate tanks received similar repairs and mitigation. Refer to the "Similar Service Assessment—Datasheet," which provides a place to record the required data. Data should be collected for each of the tank characteristics listed on the datasheet for both the control tank and candidate tanks and an assessment made to determine if the services are similar. Typically, there will not be an exact match of all data, or some of the required data will not even be known. When there is not an exact match between one or more criteria, additional evaluation is necessary to determine whether the tanks can be considered to be in similar service. Figure H.1 illustrates the steps in conducting a similar service assessment. The "Similar Service Assessment—Datasheet" is to facilitate the comparison of data for the two tanks. If the criteria for the control tank and candidate tank match, the candidate tank may be considered in similar service as the control tank for that particular criterion.

H.2.1 Additional Assessment

When additional assessment is required because an individual basic criterion does not match, the table references the section describing additional factors that must be assessed. If the additional factors in the specified reference section are assessed to be sufficiently similar, the tanks are considered in similar service for that factor. If all additional provisions are satisfied, the tanks are considered in similar service. Additional assessment(s) must be documented and maintained in the record file as per 6.8.

H.2.1.1 *Year Tank Erected*: If the criteria for the control tank and candidate tank do not match, the following additional provisions must be satisfied to consider both tanks in similar service:

a) the difference in ages of the tanks must be considered in the corrosion rate calculations, and

b) any substantive differences in the design and/or construction standards to which the tanks were constructed must be considered in the similar service evaluation.

H.2.1.2 *Bottom Material*: If the criteria for the control tank and candidate tank do not match, the following additional provisions must be satisfied to consider both tanks in similar service:

a) the bottom material of the candidate tank must have similar corrosion-resistance properties as the bottom material of the control tank,

b) the candidate tank, or both the candidate and the control tanks, utilize an effective lining to prevent corrosion of the product-side of the bottom, and

c) the potential for corrosion of the soil-side of the bottom is assessed to be similar for both tank bottom materials.

H.2.1.3 *Shell Material*: If the criteria for the control tank and candidate tank do not match, the following additional provisions must be satisfied to consider both tanks in similar service:

a) the shell material of the candidate tank must have similar corrosion-resistance properties as the shell material of the control tank,

b) the candidate tank, or both the candidate and the control tanks, utilize a suitable lining to prevent corrosion of the product-side of the shell, and

c) the candidate tank, or both the candidate and the control tanks, utilize a suitable paint or coating to prevent corrosion of the external side of the shell.

H.2.1.4 *Corrosion Allowance, Bottom/Shell*: If the criteria for the control tank and candidate tank do not match, the difference in corrosion allowance should be accounted for in the remaining life and inspection interval calculations to consider both tanks in similar service.

H.2.1.5 *Bottom Lining Type/Thickness/Age*: If the criteria for the control tank and candidate tank do not match, the differences in the bottom lining systems must be assessed. The provisions of API 652 should be used to assess the relative corrosion protection provided by the different lining systems.

H.2.1.6 *Cathodic Protection*: If the criteria for the control tank and candidate tank do not match, the following additional provisions shall apply. The provisions of API 651 should be used to assess the relative corrosion protection provided by the cathodic protection systems:

a) if the candidate tank is protected with a properly designed and functional cathodic protection system, and the control tank is not, the candidate tank may be considered to be in similar service with respect to cathodic protection;

b) if the control tank is protected with a properly designed and functional cathodic protection system, and the candidate tank is not, the candidate tank may not be considered to be in similar service with respect to cathodic protection;

c) if the control tank and the candidate tank are protected with properly designed and functional cathodic protection systems, the tanks may be considered to be in similar service with respect to cathodic protection.

H.2.1.7 *Double Bottom*: If the candidate tank and/or the control tank has multiple bottoms, the similar service assessment of soil-side corrosion should be based on the material that is in contact with the underside of the primary (upper) bottom plate

H.2.1.8 *Soil/Material in Contact with Bottom Plate*: Any differences in the following factors between the control and the candidate tank must be assessed in determining whether the candidate tank is in similar service as the control tank:

a) soil or material type;

b) pH;

c) alkalinity;

d) moisture;

e) salinity;

f) resistivity;

g) oil type (if oiled sand foundation);

h) soil/material cleanliness;

i) soil gradation;

j) chlorides;

k) sulfates.

H.2.1.9 *Ambient Conditions*: Any differences in the following factors between the control tank and the candidate tank must be assessed in determining whether the candidate tank is in similar service as the control tank:

a) low one day mean temperature;

b) exposure to salt air or other corrosive elements.

H.2.1.10 *Current Service Conditions*: Any differences in the following factors between the control tank and the candidate tank must be assessed in determining whether the candidate tank is in similar service as the control tank:

a) product classification (see Table H.1);

b) specific gravity of liquid;

c) Reid vapor pressure at 15 °C (60 °F);

d) normal operating temperature;

e) inert gas blanket, if used;

f) water bottom, if used;

g) sulfur content;

h) length of time in service;

i) product corrosivity.

H.2.1.11 *Previous Service Conditions*: If the control tank and/or candidate tank have previously been used for different services than the current service, the same factors described in H.2.1.10 should be evaluated for the previous service conditions.

H.2.1.12 *Product Classification*: Table H.1 classifies a wide variety of liquids commonly stored in aboveground storage tanks. This table serves as guidance in assessing current or previous service conditions.

H.2.1.13 *Additional Considerations*: In addition to the factors discussed above, the following data, if available for the control tank and the candidate tank, should be assessed in determining whether the candidate tank is in similar service as the control tank:

a) MFL data for the tank bottom;

b) ultrasonic thickness (UT) measurement data;

c) fiber optic monitoring system data;

d) cathodic protection monitoring tube data;

e) tank bottom integrity testing data;

f) maintenance procedures, including frequency and methods of tank cleaning.

H.3 Example of Remaining Life Determination

H.3.1 Tank Bottom

Figure H.2 illustrates one method of determining the time interval in which a tank bottom will reach its minimum bottom plate thickness, beyond which the tank should be repaired or removed from service. In this example, the original metal thickness was 6 mm ($^1/_4$ in.) when the tank was constructed in 1970. The minimum bottom plate thickness at the next inspection interval was 1.27 mm (0.05 in.). (See also Table 4.4.) At the time of this evaluation (June 10, 1990), the tank was in sour crude service. Previous service included 20 years in sour crude service. Based on thicknesses measured and the calculated corrosion rate, the remaining life, or time to reach the minimum bottom plate thickness of 1.27 mm (0.050 in.) is projected to be approximately 20 years, or June 10, 2010.

H.3.2 Tank Shell

Figure H.3 illustrates one method of determining the time interval in which a tank shell course will reach its limit of metal loss, beyond which the tank should be repaired or removed from service. In this example, the original metal thickness was 13 mm ($^1/_2$ in.) when the tank was constructed in 1990. The limit of metal loss of the top shell course was calculated to be 6 mm ($^1/_4$ in.). At the time of this evaluation (November 15, 2002), the tank was in sweet gasoline service. Previous services included nearly seven years in sweet crude and nearly three years in sour crude service. Based on thicknesses measured at periodic inspections and corrosion rates calculated from them, the remaining life, or time to reach the metal loss limit of 6 mm ($^1/_4$ in.) is projected to be approximately four years, or August 1, 2006. See 4.3.3 for the minimum thickness calculation for an entire shell course.

Table H.1—Similar Service Product Classification

Class	Description	Example
A	Low sulfur light oil (< 1 % sulfur)	No. 2 fuel oil, diesel, kerosene, jet fuel, gasoline
B	High sulfur light oil (> 1 % sulfur)	Unfinished heating oil, distillate
C	Sweet sulfur heavy oil (< 1 % sulfur)	Heavy gas oil and sweet residual
D	Sour sulfur heavy oil (> 1 % sulfur)	Sour residual
E	Slop and process water	See description
F	Finished lube oil	Automotive, diesel and aviation oil
G	Sludge	Acidic, non-acidic
H	Crude oils	Light volatile oil (Class 1)
		Non-sticky oil (Class 2)
		Heavy sticky oil (Class 3)
		Non-fluid (heavy crude, high paraffin) (Class 4)
I	Additive	Gasoline performance additives
J	Solvent	Ketones, alcohol, toluene, xylene, glycols, glycol ethers
K	Chemicals	Phosphoric, sulfuric, hydrochloric, formic, and nitric acids
NOTE This table is not all inclusive. Additionally, there may be significant variability in the chemical composition of products within a listed classification.		

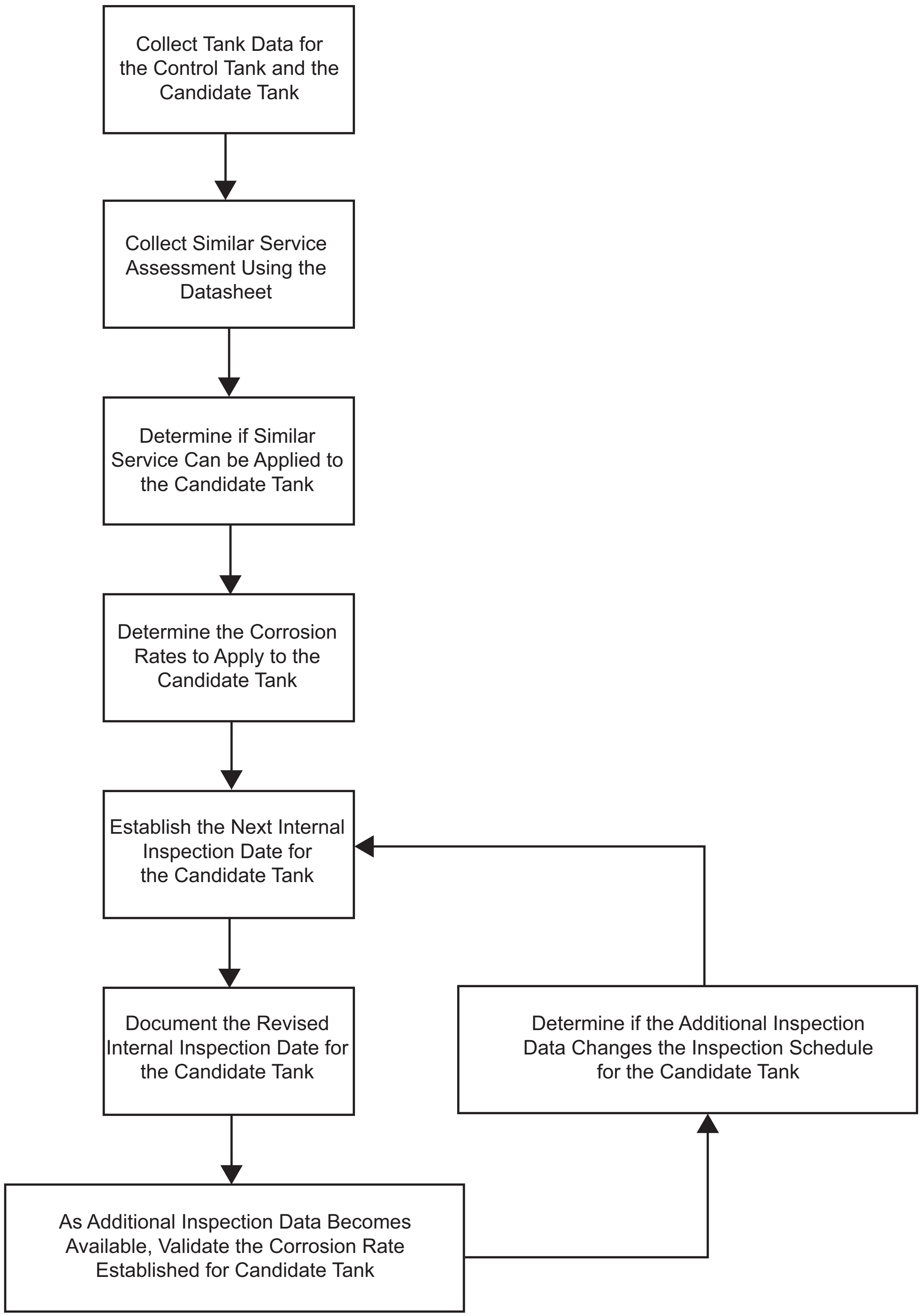

Figure H.1—Steps in Conducting Similar Service Assessment

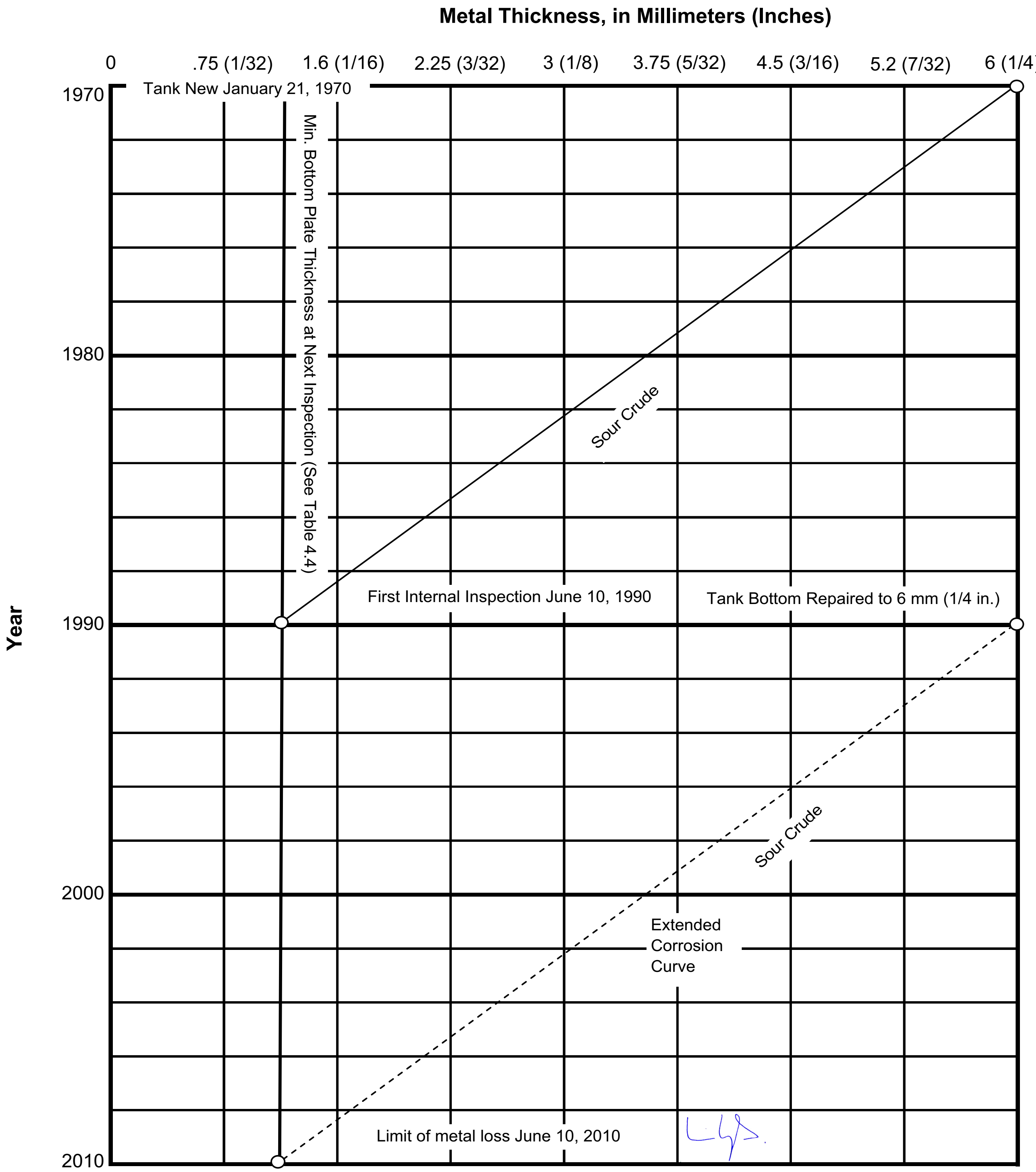

Figure H.2—Example Corrosion Rate Curves for Bottom of Storage Tank

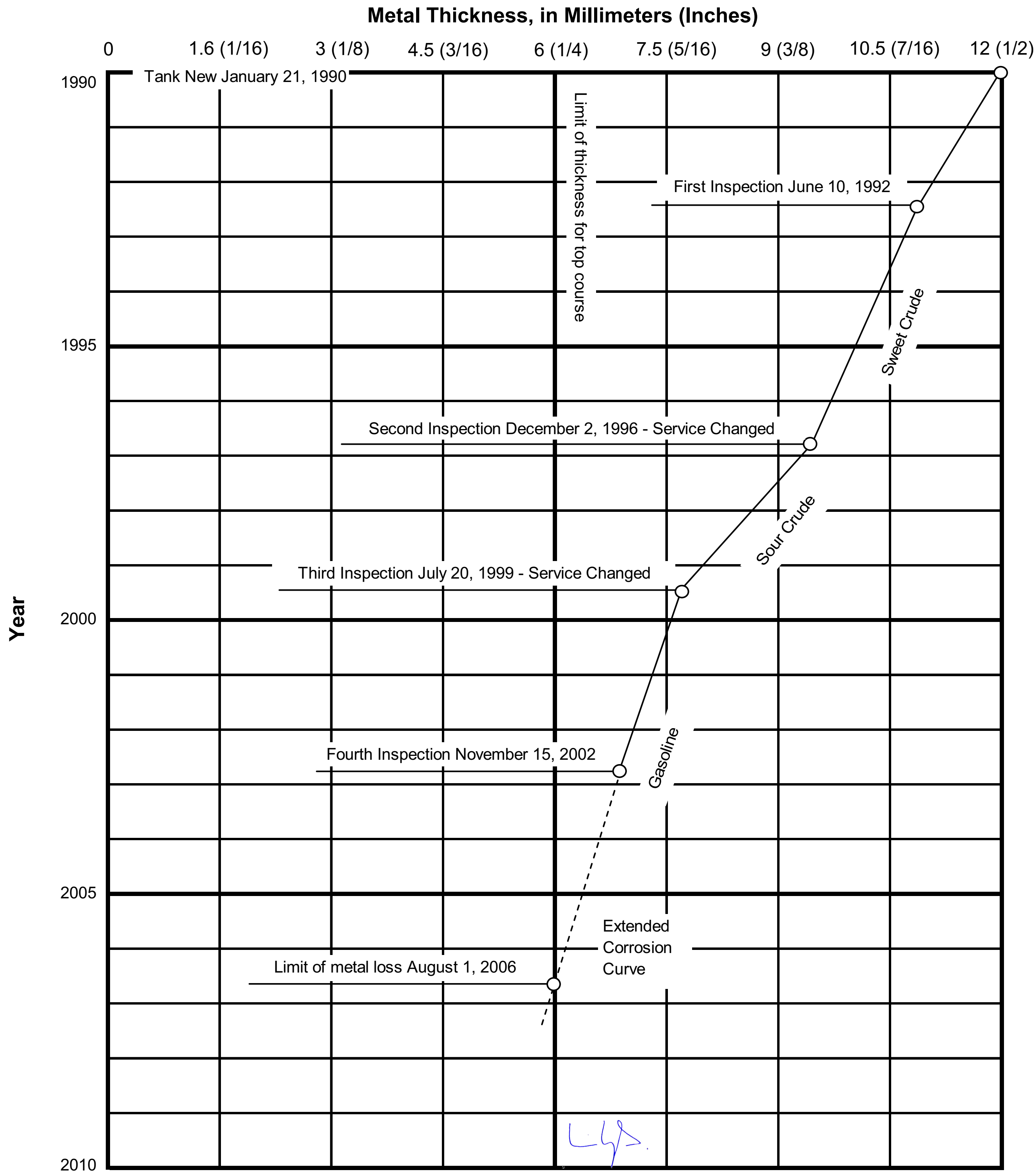

Figure H.3—Example Corrosion Rate Curves for Top Course of Storage Tank

SIMILAR SERVICE ASSESSMENT—DATASHEET

CONTROL TANK ID: __________ LOCATION: __________
DIAMETER m (ft): __________ HEIGHT m (ft): __________ CAPACITY: __________ BBLS

CANDIDATE TANK ID: __________ LOCATION: __________
DIAMETER m (ft): __________ HEIGHT m (ft): __________ CAPACITY: __________ BBLS

SECTION 1—TANK BOTTOM (PRODUCT-SIDE) ASSESSMENT

H.1.1 **TANK CHARACTERISTICS**

	Control Tank [1]	Candidate Tank [2]	MATCH [3] Yes	MATCH [3] No	IF NO, SEE SEC.[4]
a) YEAR TANK ERECTED			☐	☐	H.2.1.1
b) BOTTOM MATERIAL			☐	☐	H.2.1.2
c) CORROSION ALLOWANCE			☐	☐	H.2.1.4
d) BOTTOM LINING TYPE			☐	☐	H.2.1.5
e) BOTTOM LINING THICKNESS			☐	☐	H.2.1.5
f) BOTTOM LINING AGE			☐	☐	H.2.1.5

H.1.2 **CURRENT SERVICE CONDITIONS**

	Control Tank [1]	Candidate Tank [2]	MATCH [3] Yes	MATCH [3] No	IF NO, SEE SEC.[4]
a) CURRENT PRODUCT NAME			☐	☐	H.2.1.10
b) PRODUCT CLASS. (TABLE H.1)			☐	☐	H.2.1.10
c) SPECIFIC GRAVITY OF PRODUCT			☐	☐	H.2.1.10
d) NORMAL OPERATING TEMP.			☐	☐	H.2.1.10
e) WATER BOTTOM?			☐	☐	H.2.1.10
f) SULFUR CONTENT			☐	☐	H.2.1.10
g) TIME IN THIS SERVICE			☐	☐	H.2.1.10
h) PRODUCT CORROSIVITY			☐	☐	H.2.1.10

H.1.3 **PREVIOUS SERVICE CONDITIONS**

	Control Tank [1]	Candidate Tank [2]	MATCH [3] Yes	MATCH [3] No	IF NO, SEE SEC.[4]
a) PREVIOUS PRODUCT NAME			☐	☐	H.2.1.10
b) PRODUCT CLASS. (TABLE H.1)			☐	☐	H.2.1.10
c) SPECIFIC GRAVITY OF PRODUCT			☐	☐	H.2.1.10
d) NORMAL OPERATING TEMP.			☐	☐	H.2.1.10
e) WATER BOTTOM?			☐	☐	H.2.1.10
f) SULFUR CONTENT			☐	☐	H.2.1.10
g) TIME IN THIS SERVICE			☐	☐	H.2.1.10
h) PRODUCT CORROSIVITY			☐	☐	H.2.1.10

H.1.4 **CONCLUSIONS**

a) Does this assessment include additional assessment documentation (see H.2.1), YES ☐ or NO ☐

b) Based on the criteria reviewed in this similar service evaluation,
similar service is ☐ OR is NOT ☐ recommended for this tank (check appropriate box)

c) The corrosion rate to be applied to the product side of the tank bottom is: ___________mpy.

COMMENTS:

____

____

NOTE THE DATASHEET SHALL BE MAINTAINED IN THE RECORD FILE AS PER 6.8.

ASSESSED BY: __________ DATE: __________

APPROVED BY: __________ DATE: __________
(tank owner/operator)

NOTE 1 The control tank is the tank for which service conditions and corrosion rates are well known.
NOTE 2 The candidate tank is the tank to be compared to the control tank to determine if similar service concepts apply.
NOTE 3 "Y" or "Yes" indicates that the candidate tank criterion essentially matches the control tank .
NOTE 4 If the candidate tank criterion does not match the control tank criterion, see H.2.1.

SIMILAR SERVICE ASSESSMENT—DATASHEET

CONTROL TANK ID: ________________ LOCATION: ________________________

DIAMETER m (ft): ____________ HEIGHT m (ft): ____________ CAPACITY: ___________ BBLS

CANDIDATE TANK ID: ________________ LOCATION: ________________________

DIAMETER m (ft): ____________ HEIGHT m (ft): ____________ CAPACITY: ___________ BBLS

SECTION 2—TANK BOTTOM (SOIL-SIDE) ASSESSMENT

H.2.1 **TANK CHARACTERISTICS**

	Control Tank [1]	Candidate Tank [2]	MATCH [3] Yes	MATCH [3] No	IF NO, SEE SEC. [4]
a) YEAR TANK ERECTED	______	______	☐	☐	H.2.1.1
b) BOTTOM MATERIAL	______	______	☐	☐	H.2.1.2
c) CORROSION ALLOWANCE	______	______	☐	☐	H.2.1.4
d) DOUBLE BOTTOM	______	______	☐	☐	H.2.1.7

H.2.2 **SOIL/MATERIAL IN CONTACT WITH OR AROUND BOTTOM PLATE [5]**

	Control Tank [1]	Candidate Tank [2]	MATCH [3] Yes	MATCH [3] No	IF NO, SEE SEC. [4]
a) SOIL TYPE	______	______	☐	☐	H.2.1.8
b) SOIL pH	______	______	☐	☐	H.2.1.8
c) SOIL ALKALINITY	______	______	☐	☐	H.2.1.8
d) SOIL MOISTURE	______	______	☐	☐	H.2.1.8
e) SOIL SALINITY	______	______	☐	☐	H.2.1.8
f) SOIL CONDUCTIVITY	______	______	☐	☐	H.2.1.8
g) OIL TYPE (IF OIL SAND FOUNDATION)	______	______	☐	☐	H.2.1.8
h) SOIL CLEANLINESS	______	______	☐	☐	H.2.1.8

H.2.3 **CURRENT OPERATING CONDITIONS**

	Control Tank [1]	Candidate Tank [2]	MATCH [3] Yes	MATCH [3] No	IF NO, SEE SEC. [4]
a) NORMAL OPERATING TEMP.	______	______	☐	☐	H.2.1.10
b) CATHODIC PROTECTION [5]	______	______	☐	☐	H.2.1.6
c) PONDING/WATER	______	______	☐	☐	H.2.1.8

H.2.4 **PREVIOUS OPERATING CONDITIONS**

	Control Tank [1]	Candidate Tank [2]	MATCH [3] Yes	MATCH [3] No	IF NO, SEE SEC. [4]
a) NORMAL OPERATING TEMP.	______	______	☐	☐	H.2.1.10
b) CATHODIC PROTECTION [5]	______	______	☐	☐	H.2.1.6
c) PONDING/WATER	______	______	☐	☐	H.2.1.8

H.2.5 **CONCLUSIONS**

a) Does this assessment include additional assessment documentation (see H.2.1), YES ☐ or NO ☐

b) Based on the criteria reviewed in this similar service evaluation,
similar service is ☐ OR is NOT ☐ recommended for this tank (check appropriate box)

c) The corrosion rate to be applied to the soil side of the tank bottom is: ___________mm per year (mils per year).

COMMENTS:

____

____

NOTE THE DATASHEET SHALL BE MAINTAINED IN THE RECORD FILE AS PER 6.8.

ASSESSED BY: ______________________________ DATE: ______________________

APPROVED BY: ______________________________ DATE: ______________________
(tank owner/operator)

NOTE 1 The control tank is the tank for which service conditions and corrosion rates are well known.
NOTE 2 The candidate tank is the tank to be compared to the control tank to determine if similar service concepts apply.
NOTE 3 "Y" or "Yes" indicates that the candidate tank criterion essentially matches the control tank .
NOTE 4 If the candidate tank criterion does not match the control tank criterion, see H.2.1.
NOTE 5 See API 651, Section 5.3.

SIMILAR SERVICE ASSESSMENT—DATASHEET

CONTROL TANK ID: ____________ LOCATION: ____________
DIAMETER m (ft): ________ HEIGHT m (ft): ________ CAPACITY: ________ BBLS

CANDIDATE TANK ID: ____________ LOCATION: ____________
DIAMETER m (ft): ________ HEIGHT m (ft): ________ CAPACITY: ________ BBLS

SECTION 3—TANK SHELL (PRODUCT-SIDE) ASSESSMENT

H.3.1 **TANK CHARACTERISTICS**

	Control Tank [1]	Candidate Tank [2]	MATCH [3] Yes	No	IF NO, SEE SEC. [4]
a) YEAR TANK ERECTED			☐	☐	H.2.1.1
b) SHELL MATERIAL			☐	☐	H.2.1.3
c) CORROSION ALLOWANCE			☐	☐	H.2.1.4
d) SHELL LINING TYPE			☐	☐	H.2.1.5
e) SHELL LINING THICKNESS			☐	☐	H.2.1.5
f) SHELL LINING AGE			☐	☐	H.2.1.5

H.3.2 **AMBIENT CONDITIONS**

	Control Tank [1]	Candidate Tank [2]	MATCH [3] Yes	No	IF NO, SEE SEC. [4]
a) LOW ONE DAY MEAN TEMP.			☐	☐	H.2.1.9
b) EXPOSURE TO SALT AIR			☐	☐	H.2.1.9

H.3.3 **CURRENT SERVICE CONDITIONS:**

	Control Tank [1]	Candidate Tank [2]	MATCH [3] Yes	No	IF NO, SEE SEC. [4]
a) CURRENT PRODUCT NAME			☐	☐	H.2.1.10
b) PRODUCT CLASS. (TABLE H.1)			☐	☐	H.2.1.10
c) SPECIFIC GRAVITY OF PRODUCT			☐	☐	H.2.1.10
d) REID VAPOR PRESSURE @ 60 °F			☐	☐	H.2.1.10
e) NORMAL OPERATING TEMP.			☐	☐	H.2.1.10
f) INERT GAS BLANKET?			☐	☐	H.2.1.10
g) WATER BOTTOM?			☐	☐	H.2.1.10
h) SULFUR CONTENT			☐	☐	H.2.1.10
i) TIME IN THIS SERVICE			☐	☐	H.2.1.10
j) PRODUCT CORROSIVITY			☐	☐	H.2.1.10

H.3.4 **PREVIOUS SERVICE CONDITIONS**

	Control Tank [1]	Candidate Tank [2]	MATCH [3] Yes	No	IF NO, SEE SEC. [4]
a) PREVIOUS PRODUCT NAME			☐	☐	H.2.1.10
b) PRODUCT CLASS. (TABLE H.1)			☐	☐	H.2.1.10
c) SPECIFIC GRAVITY OF PRODUCT			☐	☐	H.2.1.10
d) REID VAPOR PRESSURE @ 60 °F			☐	☐	H.2.1.10
e) NORMAL OPERATING TEMP.			☐	☐	H.2.1.10
f) INERT GAS BLANKET?			☐	☐	H.2.1.10
g) WATER BOTTOM?			☐	☐	H.2.1.10
h) SULFUR CONTENT			☐	☐	H.2.1.10
i) TIME IN THIS SERVICE			☐	☐	H.2.1.10
j) PRODUCT CORROSIVITY			☐	☐	H.2.1.10

H.3.5 **CONCLUSIONS**

a) Does this assessment include additional assessment documentation (see H.2.1), YES ☐ or NO ☐

b) Based on the criteria reviewed in this similar service evaluation,
similar service is ☐ OR is NOT ☐ recommended for this tank (check appropriate box)

c) The corrosion rate to be applied to the product side of the tank shell is: ___________mm per year (mils per year).

COMMENTS:

____

____

SIMILAR SERVICE ASSESSMENT—DATASHEET

NOTE THE DATASHEET SHALL BE MAINTAINED IN THE RECORD FILE AS PER 6.8.

SUBMITTED BY: ____________________ DATE: ____________________

APPROVED BY: ____________________ DATE: ____________________

NOTE 1 The control tank is the tank for which service conditions and corrosion rates are well known.
NOTE 2 The candidate tank is the tank to be compared to the control tank to determine if similar service concepts apply.
NOTE 3 “Y” or “Yes” indicates that the candidate tank criterion essentially matches the control tank .
NOTE 4 If the candidate tank criterion does not match the control tank criterion, see H.2.1.

SIMILAR SERVICE ASSESSMENT—DATASHEET

CONTROL TANK ID: ____________ LOCATION: ____________
DIAMETER m (ft): ________ HEIGHT m (ft): ________ CAPACITY: ________ BBLS

CANDIDATE TANK ID: ____________ LOCATION: ____________
DIAMETER m (ft): ________ HEIGHT m (ft): ________ CAPACITY: ________ BBLS

SECTION 4—TANK SHELL (EXTERNAL SIDE) ASSESSMENT

H.4.1 **TANK CHARACTERISTICS**

	Control Tank [1]	Candidate Tank [2]	MATCH [3] Yes	MATCH [3] No	IF NO, SEE SEC. [4]
a) YEAR TANK ERECTED			☐	☐	H.2.1.1
b) SHELL MATERIAL			☐	☐	H.2.1.3
c) CORROSION ALLOWANCE			☐	☐	H.2.1.4
d) INSULATION TYPE			☐	☐	H.2.1.4
e) INSULATION THICKNESS			☐	☐	H.2.1.4
f) INSULATION AGE			☐	☐	H.2.1.4
g) COATING TYPE			☐	☐	H.2.1.4
h) COATING THICKNESS			☐	☐	H.2.1.4
i) COATING AGE			☐	☐	H.2.1.4

H.4.2 **AMBIENT CONDITIONS**

	Control Tank [1]	Candidate Tank [2]	MATCH [3] Yes	MATCH [3] No	IF NO, SEE SEC. [4]
a) LOW ONE DAY MEAN TEMP.			☐	☐	H.2.1.9
b) EXPOSURE TO SALT AIR			☐	☐	H.2.1.9

H.4.3 **CURRENT OPERATING CONDITIONS**

	Control Tank [1]	Candidate Tank [2]	MATCH [3] Yes	MATCH [3] No	IF NO, SEE SEC. [4]
a) PONDING/WATER			☐	☐	H.2.1.10
b) NORMAL OPERATING TEMP.			☐	☐	H.2.1.10

H.4.4 **PREVIOUS OPERATING CONDITIONS**

	Control Tank [1]	Candidate Tank [2]	MATCH [3] Yes	MATCH [3] No	IF NO, SEE SEC. [4]
a) PONDING/WATER			☐	☐	H.2.1.10
b) NORMAL OPERATING TEMP.			☐	☐	H.2.1.10

H.4.5 **CONCLUSIONS**

a) Does this assessment include additional assessment documentation (see H.2.1), YES ☐ or NO ☐

b) Based on the criteria reviewed in this similar service evaluation,
similar service is ☐ OR is NOT ☐ recommended for this tank (check appropriate box)

c) The corrosion rate to be applied to the ambient side of the tank shell is: ___________mm per year (mils per year).

COMMENTS:

____

____

____

NOTE THE DATASHEET SHALL BE MAINTAINED IN THE RECORD FILE AS PER 6.8.

ASSESSED BY: ____________ DATE: ____________

APPROVED BY: ____________ DATE: ____________
(tank owner/operator)

NOTE 1 The control tank is the tank for which service conditions and corrosion rates are well known.
NOTE 2 The candidate tank is the tank to be compared to the control tank to determine if similar service concepts apply.
NOTE 3 “Y” or “Yes” indicates that the candidate tank criterion essentially matches the control tank .
NOTE 4 If the candidate tank criterion does not match the control tank criterion, see H.2.1.

SIMILAR SERVICE ASSESSMENT—DATASHEET

CONTROL TANK ID: ____________________ LOCATION: ________________________
DIAMETER m (ft): ___________ HEIGHT m (ft): _____________ CAPACITY: ___________ BBLS

CANDIDATE TANK ID: ____________________ LOCATION: ________________________
DIAMETER m (ft): _____________ HEIGHT m (ft): _______________ CAPACITY: ___________ BBLS

SECTION 5—CONCLUSION SUMMARY

a) From Section 1, the corrosion rate to be applied to the product-side of the tank bottom is: ___________mm per year (mils per year).

b) From Section 2, the corrosion rate to be applied to the soil-side of the tank bottom is: ___________mm per year (mils per year).

c) From Section 3, the corrosion rate to be applied to the product-side of the tank shell is: ___________mm per year (mils per year).

d) From Section 4, the corrosion rate to be applied to the external side of the tank shell is: ___________mm per year (mils per year).

e) Based on the corrosion rates applied, the next internal inspection for this tank will be completed in Year _________.

COMMENTS:

____

____

____

____

NOTE THE DATASHEET SHALL BE MAINTAINED IN THE RECORD FILE AS PER 6.8.

ASSESSED BY: ______________________________ DATE: ________________________

APPROVED BY: ______________________________ DATE: ________________________
(tank owner/operator)

Annex I
(informative)

Inquiries and Suggestions for Change

I.1 Introduction

This annex describes the process established by API for 1) submitting inquiries to API, and 2) for submitting suggestions for changes to this standard. Inquiries and suggestions for change are welcome and encouraged because they provide useful reader feedback to the responsible API Committee regarding technical accuracy, current technology use, clarity, consistency, and completeness of the standard. API will attempt to answer all valid inquiries. Submittals not complying with this Annex will be returned unanswered.

Sections I.2 through I.7, below, cover the submitting of inquiries. See Section I.8 for instructions about submitting suggestions for change.

I.2 Inquiry References

I.2.1 API maintains several websites that provide information that should be considered when considering submitting an inquiry.

I.2.2 Your inquiry may have been previously formally addressed by the Subcommittee and the resulting interpretation posted on the API website as follows:

— For all standards: http://mycommittees.api.org/standards/techinterp/default.aspx

— For Refining Standards: http://mycommittees.api.org/standards/techinterp/refequip/default.aspx

For both links, click on the standard in question to download the file.

I.2.3 In addition, an addendum or errata, which may have addressed your issue, can be found on the API website as follows:

— For all standards: http://www.api.org/standards/addenda/

— For Refining Standards: http://www.api.org/standards/addenda/add-ref.cfm

I.3 Definitions

I.3.1 Inquiry: A question that asks what is the meaning of a specific paragraph, figure, or table in the standard; i.e. what do the words say. It is not a question that asks about the intention of the standard.

I.3.2 The answer to the inquiry. Typically, the answer is simply a “Yes” or “No” response, with a brief clarification if needed. This term is also used to refer to the combined question and answer.

I.4 API Policy Regarding Inquiries

I.4.1 API has established the following limits on its activity in the handling of inquiries.

a) API does not approve, certify, rate, or endorse any item, construction, proprietary device, or activity.

b) API does not act as a consultant on specific engineering problems.

c) API does not provide information on the general understanding or application of the standard.

I.4.2 All inquiries that result in interpretations will be made available to the public on the API website.

I.5 Submission of Inquiries

I.5.1 An electronic form for submitting a request can be found on the API Web site at http://rfi.api.org/. Please use this means to submit your inquiry.

I.5.2 All inquiries must comply with the following.

a) Current standard: If an inquiry refers to a version or addendum that is not the latest, the Subcommittee will develop the interpretation based on the requirements stated in the current version.

b) Specific Reference: The applicable paragraph number, figure number, or table number must be cited in the inquiry.

c) Sentence Structure: Inquiries must be written such that the answer can be a YES or NO, with technical details added if necessary. The inquiry statement should be technically and editorially correct, and written in understandable English.

d) Background: Providing a background explanation is optional, but is encouraged to assist the committee in understanding the query.

e) Single Subject: The scope of an inquiry shall be limited to a single subject or a group of closely related subjects.

f) General Format:

1) The general format of the inquiry should be as follows: "Does Paragraph XXX of API-6XX require that ….?"

2) The inquirer shall state what is required in his or her option, as the answer to the query.

3) If a revision to the standard is believed to also be needed, provide recommended wording.

g) The Inquirer should not use the inquiry process to improve his general understanding, design skills, and usage of the standard. Consultants not affiliated with API are available for this purpose.

h) It is important that the Inquirer understand the difference between an inquiry and a suggestion for change. API encourages both, but the submittal and committee handling procedures are different.

I.5.3 General guidelines for submission can also be found on the API web site at:

http://www.api.org/Publications-Standards-and-Statistics/FAQs-and-Inquiries/FAQs/Technical-Question/Guidelines-for-submission.aspx

I.6 Typical Inquiry Procedure

I.6.1 The typical procedure of an inquiry is as follows.

a) The Inquirer must prepare the inquiry, including any necessary background information, in full compliance with this Annex and submit to the API Standards Coordinator.

b) API Standards Coordinator checks the inquiry to verify compliance with the requirements of submitting an inquiry.

c) If the inquiry cannot be answered for any reason, the Coordinator will issue a response to the inquirer advising the reason(s) for not answering the inquiry. A form or checklist will typically be used for this response.

d) If the Coordinator believes inquiry is valid, it will be forwarded to the Subcommittee for study, and the inquirer will be advised using the form letter.

e) The Subcommittee will evaluate the inquiry and either develop a response or determine that the inquiry cannot be answered, and advise the Coordinator accordingly. The Subcommittee will consider the need for modifying the standard to resolve technical issues, add new requirements, make editorial corrections, improve clarity, remove conflicts, etcetera.

f) The Subcommittee will develop inquiries in accordance with the balloting requirements in the API Procedures for Standards Development. All inquiries shall also be submitted to API's Office of the General Counsel for review and approval. Upon approval and clearance, the inquiry will be published on the API website.

I.6.2 The time required to process a valid inquiry as described in I.6.1 may take as long as a year.

I.7 Interpretations Responding to Inquiries

I.7.1 An interpretation is written by the Subcommittee to provide the specific answer to an inquiry. It typically will not state the intent of the standard, nor give reasons for the requirements, nor give historical bases, nor provide overall understanding of the standard. If the inquiry is properly phrased, the interpretation can be a one-word response. With many inquiries, there may be a need to provide clarifying statements, such as the limits on the applicability.

I.7.2 Although it is not possible to develop interpretations quickly to remedy immediate needs, the industry benefits as a whole when inquiries are utilized as a means of trying to understand the technical requirements in the standard.

I.8 Suggestions for Changes

I.8.1 "Suggestion for Change" is not an inquiry; it is simply a communication (email preferred) from a reader to API proposing that a specific change be made to the standard.

I.8.2 Any format is acceptable, as long as the content is clear.

I.8.3 The most effective means to submit suggestions is to send an email to the API Coordinator (standards@api.org).

I.8.4 The content of a suggestion must include the standard number, edition, and addendum in question. The relevant paragraph numbers, table number, figure number, etc. must also be stated. Provide as much explanation as necessary to be sure the Subcommittee understands the technical issues. Provide specific language that you think is needed to implement the change. Last, include your name, company affiliation if any, and your return email or mailing address.

I.8.5 API will forward all suggestions that are suitably written to the Subcommittee for consideration. The Subcommittee will evaluate each suggestion and determine if a change is needed. Suggestions that are accepted by the Subcommittee will be reflected in a future edition or addenda, but a reply advising the submitter of the Subcommittee's decision may not be issued.

Annex J
(normative, if specified by the purchaser)

Shell Plate Repairs Using Nonmetallic Materials

J.1 Introduction

J.1.1 This annex specifies requirements and provides guidance for utilizing composite repair systems to repair the shell of a tank, when specified or authorized by the owner/operator. Composite repair systems shall not be used to repair existing tanks for change of service applications, for reconstructed tanks, for strengthening of tank floors, nor for the strengthening in the bottom 300 mm (12 in.) of the shell where discontinuity stresses/strains are difficult to predict. Thick filmed liners (fiberglass) are not included in this list of unacceptable repairs.

J.2 Repairs Using Nonmetallic Composite Materials

J.2.1 The composite repair systems shall be designed and tested in accordance with ASME PCC-2, Part 4 "Nonmetallic and Bonded Repairs", specifically Article 4.1 "Nonmetallic Composite Repair Systems: High-Risk Applications" with the additional requirements stated in Table J.1. The application of this repair system shall be limited to hoop strengthening of the shell for non-leaking (Type A) and leaking (Type B) conditions as defined in ASME PCC-2. The repair is also limited to areas greater than $\sqrt{[D*t]}$ from a structural discontinuity.

The thickness of the repairs shall be calculated according to Section 3-DESIGN from ASME PCC-2 Article 4.1 and follow the supplemental requirements found in Annex J. The length of the repair shall be calculated according to the criteria listed in "Axial Length of Repair".

A composite repair that is designed in accordance with ASME PCC-2 "Repair Laminate Allowable Stress" or "Repair Laminate Allowable Stresses Determined by Performance Testing" neglects the contribution of the tank wall for contribution of load-carrying capability and shall be considered a major repair per API 653, 3.25.

A composite repair that is designed in accordance with ASME PCC-2 "Component Allowable Stress" relies on the contribution of the tank wall for contribution of load carrying capability. If the composite repair is small enough and provides less than one-half of the strength of the shell, this type of repair shall not be considered a major repair per API 653, 3.25.

The following table presents the amendments and supplements to the identified sections of ASME PCC-2:

Table J.1—API Requirements in Addition to ASME PCC-2

PCC-2, Part 4, Article 4.1, Section Reference	PCC-2, Part 4, Article 4.1 Section Description	Additional Requirements for Storage Tank Repairs
1	**DESCRIPTIONS**	
1.3	Risk Assessment	The owner/operator shall also identify the existing substrate material, pressure/temperature limits, internal fluids, and external environmental required for the selection and design of the repair system.
3	**DESIGN**	
3.2	Repair System Qualification Data	All prescribed testing shall be conducted by a nationally accredited test facility and certified by engineers, knowledgeable about tank design and material testing.
Table 1	Repair System Required Material and Performance Properties	Design strengths per ASTM D3039 shall be determined by testing a minimum 20 samples (average strength less three standard deviations) with an environmental reduction factor applied. The environmental reduction factors are: Carbon Fiber 0.85, Aramid 0.70, and Glass 0.50.
		Testing of the components of these systems shall determine tensile strength, tensile modulus, compressive strength, long-term creep testing, interlaminar shear, material durability and long-term strength retention, considering these identified potential constraints (per ASME PCC-2 Standard Part 4 Articles).
NOTE 1: Composite materials cannot sustain long-term loads near their short-term coupon test levels as metals can. This effect is called “creep rupture”.		
NOTE 2: Composite materials do not yield as metals usually do.		
NOTE 3: Cyclical loading performance of composite materials is usually not as good as metals.		
3.3	Required Data	The design of the repair system shall identify the recommended service life, inspection and maintenance programs and shall be limited to those materials which have been tested by the manufacturer to determine acceptable durability of the materials when exposed to anticipated atmospheric (including UV), product, and service conditions.
3.4	Design Methodology	The design of the composite repair system shall be limited to hoop strengthening of the shell for non-leaking (Type A) and leaking (Type B) conditions as defined in ASME PCC-2. In addition, the design of the composite repair system is not intended to address non-tensile related forces, such as, but not limited to, wind loads, seismic loads, compression buckling, and the effects of foundation settlement. The risk assessment shall consider potential consequences that may occur due to non-tensile related forces.
		The proposed repair system shall identify the existing substrate, required surface preparation, composite material, load transfer material, primer layer adhesive, application method, curing protocol, and interlaminar adhesive.
3.4.5	Repair Laminate Allowable Stresses Determined by Performance Testing	The environmental compatibility of the composite repair system shall be assessed based on the exposure it will endure while in service, e.g. acidic, caustic, humid environments, and ultra-violet exposure. The system shall be subjected to immersion testing in accordance with ASTM C581 and demonstrate long-term strength retention per ASTM D3039. This testing shall confirm that the retained strength is greater than the design strength after being subjected to this long-term durability testing in these environments.

Table J.1—API Requirements in Addition to ASME PCC-2 (Continued)

PCC-2, Part 4, Article 4.1, Section Reference	PCC-2, Part 4, Article 4.1 Section Description	Additional Requirements for Storage Tank Repairs
3.4.10.3	Fire Performance	The composite repair system components and bonding shall be tested for fire resistance in accordance with ASTM E119 and confirmed to be flame and smoke spread resistant in accordance with ASTM E84. In addition to the fire performance in 3.4.10.3, the following items are required:
		The flame spread index of the material shall not exceed 25 and the material shall not support continued progressive combustion in air.
		The material shall be of such composition that surfaces that would be exposed by cutting through the material on any plane shall have a flame spread index not greater than 25 and shall not support continued progressive combustion.
		It shall be shown by test that the combustion properties of the material do not increase significantly as a result of long-term exposure to stored product at service pressure and temperature.
		The materials in the installed condition shall be demonstrated to be capable of being purged to be gas free or, if any remnants are within the material, they shall not increase the combustibility of the material.
4	**FABRICATION (INSTALLATION)**	
4.1	General	Documentation of the design records for the fabrication (installation) shall be made and retained for the repair life. This information shall include layers and orientation of reinforcement, preparation procedure, cure procedure and post cure. These documents shall be certified by a representative from the installation contractor.
5	**EXAMINATION**	
5.4	Inspection Methods	The composite repair system may be bonded internally or externally to restore the minimum shell plate thickness. Ultrasonic thickness readings at future in-service and out-of-service inspections shall be conducted from the opposite side of the plate, to ensure that the corrosion has not reduced the thickness. Where the opposite side of the plate is not accessible or covered by insulation, inspection of these repairs can be conducted at inspection ports designed into the application, at areas where coating is removed and patched after inspection, or by utilizing equipment that can scan through the repair system.

Annex R
(informative)

Additional References for Tank Inspection Guidance

R.1 In addition to the inspection guidance for tanks covered in this document, the industry documents listed in this annex provide guidance for inspecting tanks containing a variety of petroleum and non-petroleum liquids. Some documents referenced herein require more robust and more frequent inspections than what are recommended in API 653.

R.2 The list of references included in this annex is not exhaustive, and the user needs to do their own research to confirm recommendations.

R.3 For commodities not listed in the Scope of API 653, or for additional information, chemical manufacturers often provide inspection guidance for tanks storing their specific products.

American Petroleum Institute (API)

API 1595: *Design, Construction, Operations, Maintenance, Inspection of Aviation Pre-airfield Storage Terminals*

API Standard 12R1: *Installation, Operation, Maintenance, Inspection, and Repair of Tanks in Production Service*

API Bulletin 939-E: *Identification, Repair, and Mitigation of Cracking of Steel Equipment in Fuel Ethanol Service*

American Transport Association of America (ATA)

ATA Specification 103: *ATA Standard for Jet Fuel Quality Control at Airports*

American Water Works Association (AWWA)

AWWA M42: *Steel Water-Storage Tanks*

The Chlorine Institute

Pamphlet 5: *Bulk Storage of Liquid Chlorine*

Pamphlet 94: *Sodium Hydroxide Solution and Potassium Hydroxide Solution (Caustic) Storage Equipment and Piping Systems*

Pamphlet 163: *Hydrochloric Acid Storage and Piping Systems*

Engineering Equipment and Materials Users Association (EEMUA)

EEMUA Pub No 159: *Above Ground Flat Bottomed Storage Tanks: A Guide to Inspection Maintenance and Repair*

EEMUA Pub No 225: *Above Ground Plastic Tanks: A Guide to Their Specification, Installation, Commissioning, Inspection, Maintenance, Repair, and Disposal*

The Fertilizer Institute (TFI)

Aboveground Storage Tanks Containing Liquid Fertilizer—Recommended Mechanical Integrity Practices

Fiberglass and Piping Institute

FTP1 2007-1: *Recommended Practice for the In-service Inspection of Aboveground Atmospheric Fiberglass Reinforced Plastic (RFP) Tank and Vessels*

Institute of Petroleum (IP)

IP EI/JIG 1530: *Quality Assurance Requirements for the Manufacture, Storage and Distribution of Aviation Fuel to Airports*

Association for Material Protection and Performance (AMPP)

NACE SP0294: *Design, Fabrication and Inspection of Storage Tank Systems for Concentrated Fresh and Process Sulfuric Acid and Oleum at Ambient Temperatures*

NACE SP0205: *Design, Fabrication, and Inspection of Tanks for the Storage of Petroleum Refining Alkylation Unit Spent Sulfuric Acid at Ambient Temperatures*

National Fire Protection Association (NFPA)

NFPA 25: *Standard for the Inspection, Testing, and Maintenance of Water-based Fire Protection Systems*

Steel Tank Institute (STI)

SP001: *Standard for the Inspection of Aboveground Storage Tanks*

Unified Facilities Criteria (UFC)

UFC 3-460-1: *Design, Petroleum Fuel Facilities*

UFC 3-460-3: *Petroleum Fuel Systems Maintenance*

Annex S
(normative)

Austenitic Stainless Steel Storage Tanks

S.1 Scope

S.1.1 This annex covers the inspection, repair, alteration, and reconstruction of stainless steel tanks that were constructed in accordance with API 650, Annex S.

S.1.2 This annex states only the requirements that differ from the basic rules in this standard. For requirements not stated, the basic rules must be followed.

S.2 References

No changes to Section 2.

S.3 Definitions

No changes to Section 3.

S.4 Suitability for Service

S.4.1 In 4.2.4.1, the requirements of API 650, Section S.3.5 shall also be satisfied.

S.4.2 In 4.2.4.3, Annex M requirements shall be met for stainless steel tanks with design temperatures over 40 °C (100 °F) as modified by API 650, Sections S.3.6.2 thru S.3.6.8.

S.4.3 In 4.3.3.1, the maximum allowable stress S shall be modified as follows, for the design condition (S_d) and the hydrostatic test condition (S_t) the maximum allowable stress for all shell courses shall be the lesser of $0.95Y$ or $0.4T$.

S.4.4 Table 4.2 shall be in accordance with API 650, Table S.4. When the radiography schedule applied to the existing weld is unknown, the joint efficiency of 0.7 shall be used.

S.4.5 Section 4.3.3.5 c), shall be changed to read "Operation at temperatures over 40 °C (100 °F)."

S.4.6 In 4.3.3.6, the factor $\frac{2}{3}Y$ shall be replaced with $\frac{3}{4}Y$.

S.4.7 In 4.3.4, these rules do not cover stainless steel tanks.

S.5 Brittle Fracture

The tank is suitable for continued use in ambient temperature service.

S.6 Inspection

No changes to Section 6.

S.7 Materials

S.7.1 In 7.3.1.2, add reference to ASTM A480.

S.7.2 Structural may be shapes fabricated from plate. Plate and structural material shall meet API 650, Section S.2.

S.8 Design Considerations for Reconstructed Tanks

In 8.4.3, the allowable stress shall be revised to meet the allowable stresses of API 650, Section S.3.2.2.1.

S.9 Tank Repair and Alteration

S.9.1 In applying 9.1.1 to fabrication and construction requirements, API 650, Sections S.4.1 through S.4.9 shall be met as applicable.

S.9.2 Hot taps for stainless steels (reference Section 9.15) are not addressed by this annex.

S.10 Dismantling and Reconstruction

S.10.1 In 10.4.2, welding shall also meet the requirements of API 650, Section S.4.11.

S.10.2 Thermal cutting of stainless steel shall be by the iron powder burning, carbon arc, plasma-arc, water jet, or laser cutting methods.

S.10.3 The storage requirements of API 650, Section S.4.2 shall be met.

S.10.4 If specified by the owner/operator, the requirements of API 650, Section S.4.5 shall be met.

S.11 Welding

Welding shall also meet the requirements of API 650, Sections S.4.11 and S.4.12.

S.12 Examination and Testing

S.12.1 Any reference to magnetic particle method shall be replaced with the liquid penetrant method.

S.12.2 In 12.3, the quality of test water shall meet API 650, Section S.4.10.2.

S.13 Annexes

Annex F (NDE Requirements Summary)—any references to magnetic particle examination shall be disregarded.

Annex SC
(normative)

Stainless and Carbon Steel Mixed Materials Storage Tanks

SC.1 Scope

SC.1.1 This annex covers the inspection, repair, alteration and reconstruction of mixed material tanks constructed in accordance with API 650, Annex SC.

SC.1.2 This annex states only the requirements that differ from the basic rules in this standard, Annex S of this standard, Annex X of this standard and API 650, Annex SC. For requirements not stated, the basic rules shall be followed.

SC.1.3 In this annex the term “stainless steel” includes austenitic or duplex stainless steel unless noted otherwise.

SC.2 References

No changes to Section 2.

SC.3 Definitions

No changes to Section 3.

SC.4 Suitability for Service

SC.4.1 Add to 4.2.4.1: The requirements of API 650, Sections S.3.5 and API 650, and X.3.6, shall also be satisfied for the stainless steel components of the tank.

SC.4.2 Add to 4.2.4.3: This annex applies to tanks in non-refrigerated services with a maximum design temperature not exceeding 260 °C (500 °F). For the purposes of this annex, the design temperature shall be the maximum design temperature as specified by the owner/operator.

NOTE Exothermic reactions occurring inside unheated storage tanks can produce temperatures exceeding 40 °C (100 °F).

SC.4.3 Add to 4.3.3.1: The maximum allowable stress S shall be modified as follows, for the design condition (Sd) and the hydrotest condition (St) the maximum allowable stress for austenitic stainless steel shell courses shall be the smaller of 0.95Y or 0.4T.

SC.4.4 Table 4.2—Joint efficiencies for welded stainless joints shall be in accordance with API 650, Table S.4, or API 650, Table X.3. When the radiography schedule applied to the existing weld is unknown, then the joint efficiency of 0.7 shall be used.

SC.4.5 Revise 4.3.3.5.c to read ‘Operation at temperatures over 40 °C (100 °F).’

SC.4.6 Revise 4.3.3.6 by replacing the $^2/_3Y$ factor with $^3/_4Y$ for austenitic stainless steel components.

SC.4.7 The rules in 4.3.4 for riveted tanks do not cover mixed material tanks.

SC.5 Brittle Fracture Considerations

Evaluation of brittle fracture shall be done according to Section 5 of this standard for carbon steel, Section S.5 of this standard for austenitic stainless steel, and Section X.5 of this standard for duplex stainless steel components.

SC.6 Inspection

No Changes to Section 6.

SC.7 Materials

Materials requirements for mixed materials situations are unchanged from the base document except as modified by API 653 Appendices S and X (S.7 and X.7) for stainless steels.

SC.8 Design Considerations for Reconstructed Tanks

The allowable stress in 8.4.2 and 8.4.3 for stainless steel components shall be revised to meet the allowable stresses of API 650 Annex S or API 650 Annex X.

SC.9 Tank Repair and Alteration

SC.9.1 Add to 9.2: Shell insert plates and thickened insert plates shall be made in accordance with API 650, Section SC 3.2.2.

SC.9.2 Add to 9.3: Lap patches shall be made carbon steel to carbon steel and stainless steel to stainless steel.

SC.9.3 Add to 9.9: Shell penetrations and reinforcing shall be made in accordance with API 650, Section SC 3.4.

SC.9.4 Add to 9.11: Repair of tank bottoms shall be made in accordance with API 650, Section SC 3.1.

SC.9.5 Add to 9.15: Hot taps in stainless steel are not addressed by this annex.

SC.10 Other

For Dismantling and Reconstruction, Welding, Examination and Testing, and Annexes see the following sections of the basic document: S.10 through S.13 for austenitic stainless steel, and X.10 through X.13 for duplex stainless steel components.

Annex X
(normative)

Duplex Stainless Steel Storage Tanks

X.1 Scope

X.1.1 This annex covers the inspection, repair, alteration and reconstruction of duplex stainless steel tanks that were constructed in accordance with API 650, Annex X.

X.1.2 This annex states only the requirements that differ from the basic rules in this Standard. For requirements not stated, the basic rules shall be followed.

X.2 References

No changes to Section 2.

X.3 Definitions

No changes to Section 3.

X.4 Suitability for Service

X.4.1 In 4.2.4.1, the requirements of API 650, Section X.3.6 shall also be satisfied.

X.4.2 In 4.2.4.3, the requirements of API 650, Annex M requirements shall be satisfied for duplex stainless steel tanks with design temperatures over 40 °C (100 °F) as modified by API 650, Sections X.3.7.2 through X.3.7.5.

X.4.3 In 4.3.3.1, the maximum allowable stress S shall be calculated the same way as for carbon steel.

X.4.3.1 Y = specified minimum yield strength of the plate at design temperature; use material S32304 properties if duplex material/specification is not known.

X.4.3.2 T= specified minimum tensile strength of the plate at design temperature; use material S32304 properties if duplex material/specification is not known.

X.4.4 Joint efficiency to be used for evaluation shall be taken from API 650, Table X.3, rather than from Table 4.2. When the radiography schedule applied to the existing weld is unknown, a joint efficiency of 0.7 shall be used.

X.4.5 4.3.3.5c, shall be changed to read "Operation at temperatures over 40 °C (100 °F)."

X.4.6 The rules of 4.3.4 for riveted tanks do not cover duplex stainless steel tanks.

X.5 Brittle Fracture Considerations

X.5.1 In 5.3.2 the applicable API 650 edition and addendum for duplex stainless steel tanks is 11th edition, Addendum 1 or later.

X.5.2 5.3.5 does not apply to duplex stainless steel tanks.

X.5.3 The rules of 5.3.8 shall be replaced with the following: Tanks constructed of duplex stainless steels whose toughness testing or testing exemption conformed to API 650, Section X.2.3.3, may be considered to be adequately tough for continued operation.

X.6 Inspection

No Changes to Section 6.

X.7 Materials

X.7.1 In 7.3.1.2, add reference to ASTM A480 and A240.

X.7.2 Structural sections may be shapes fabricated from plate. Plate and structural material shall meet API 650, Section X.2.

X.8 Design Considerations for Reconstructed Tanks

In 8.4.2 and 8.4.3 the allowable stress shall be revised to meet the allowable stresses of API 650, Annex X.

X.9 Tank Repair and Alteration

X.9.1 In applying 9.1.1 to fabrication and construction requirements, API 650 , Sections X.4.1 through X.4.9 shall be met as applicable except as permitted in X.10.2 of this annex.

X.9.2 Hot taps for duplex stainless steels (reference section 9.15) are not addressed by this annex.

X.10 Dismantling and Reconstruction

X.10.1 In 10.4.2, welding shall also meet the requirements of API 650, Section X.4.11.

X.10.2 Carbon arc cutting shall not be used except when agreed to, in writing, by the Purchaser as an exception to X.9.1, for certain dismantling operations.

X.10.3 The storage requirements of API 650, Section X.4.2 shall be met.

X.10.4 When specified by the Purchaser, the requirements of API 650, Section X.4.5 shall be met.

X.11 Welding

Welding shall also meet the requirements of API 650, Sections X.4.11 and X.4.12.

X.12 Examination and Testing

X.12.1 Any reference to magnetic particle method shall be replaced with the liquid penetrant method.

X.12.2 In 12.3, the quality of test water shall meet API 650, Section X.4.10.

X.13 Annexes

Annex F, NDE Requirements Summary; any reference to magnetic particle method shall be replaced with the liquid penetrant method.

Annex Y
(informative)

Bibliography

Whether cited or not cited in this standard, the following publications may be of interest.

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

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

API Standard 2610, *Design, Construction, Operation, Maintenance, and Inspection of Terminal and Tank Facilities*

ANSI/AWS Z49.1, *Safety in Welding and Cutting and Allied Processes*

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