

Tank Inspection, Repair, Alteration, and Reconstruction

API STANDARD 653
FIFTH EDITION, NOVEMBER 2014

ADDENDUM 1, APRIL 2018
ADDENDUM 2, MAY 2020
ADDENDUM 3, NOVEMBER 2023



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Tank Inspection, Repair, Alteration, and Reconstruction

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*

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 D1.1⁴, *Structural Welding Code—Steel*

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

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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.

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.

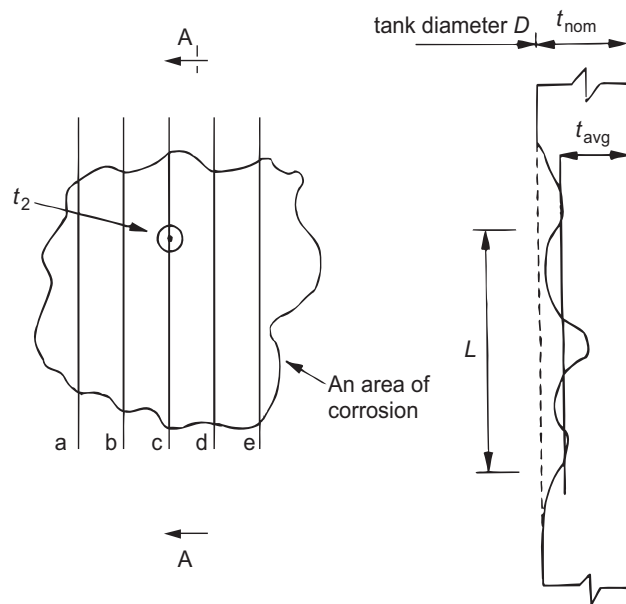
In USC units: $L = 3.7\sqrt{Dt_2}$, but not more than 40 inches

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.

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

SECTION A-A

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

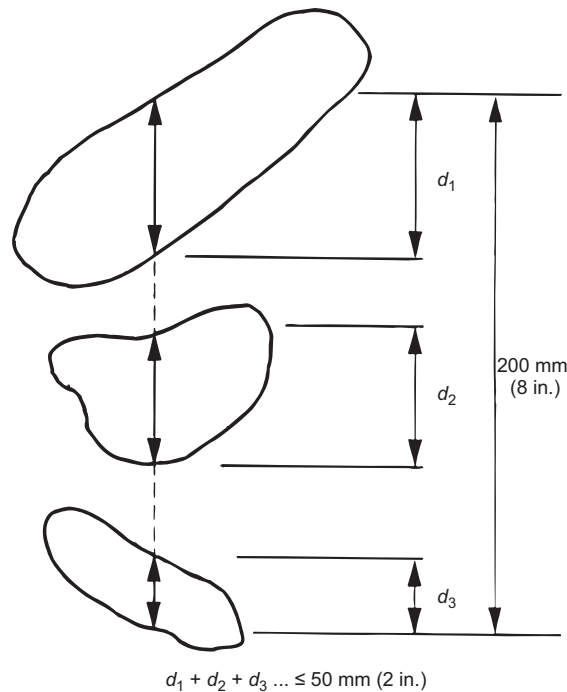


Figure 4.2—Pit Measurement

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:

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

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:

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

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

**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 (lb/in. ²)	Minimum Specified Tensile Stress, T (lb/in. ²)	Allowable Product Stress, S (lb/in. ²) ^f		Allowable Hydrostatic Test Stress S_t (lb/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 lb/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	— —
		Lap ^a	0.75	³ / ₈ in. max. t
	3rd to 13th (1940 to 1956)	Butt ^c	0.85	—
		First and Second (1936 to 1939)	Lap ^a	0.70
	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:

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

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.

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

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:

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

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

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 ($> 93\text{ }^{\circ}\text{C}$ [$200\text{ }^{\circ}\text{F}$]) 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.

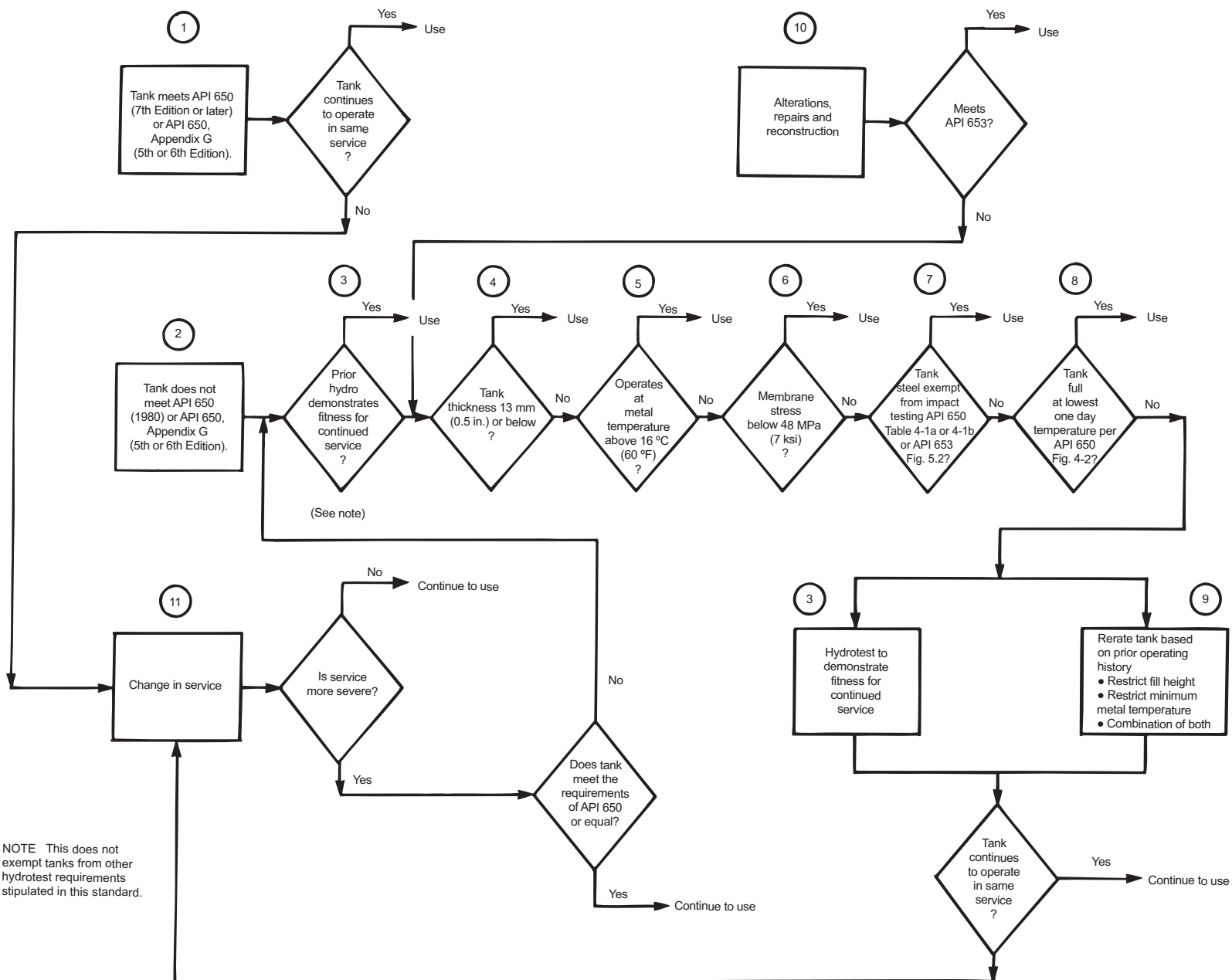


Figure 5.1—Brittle Fracture Considerations

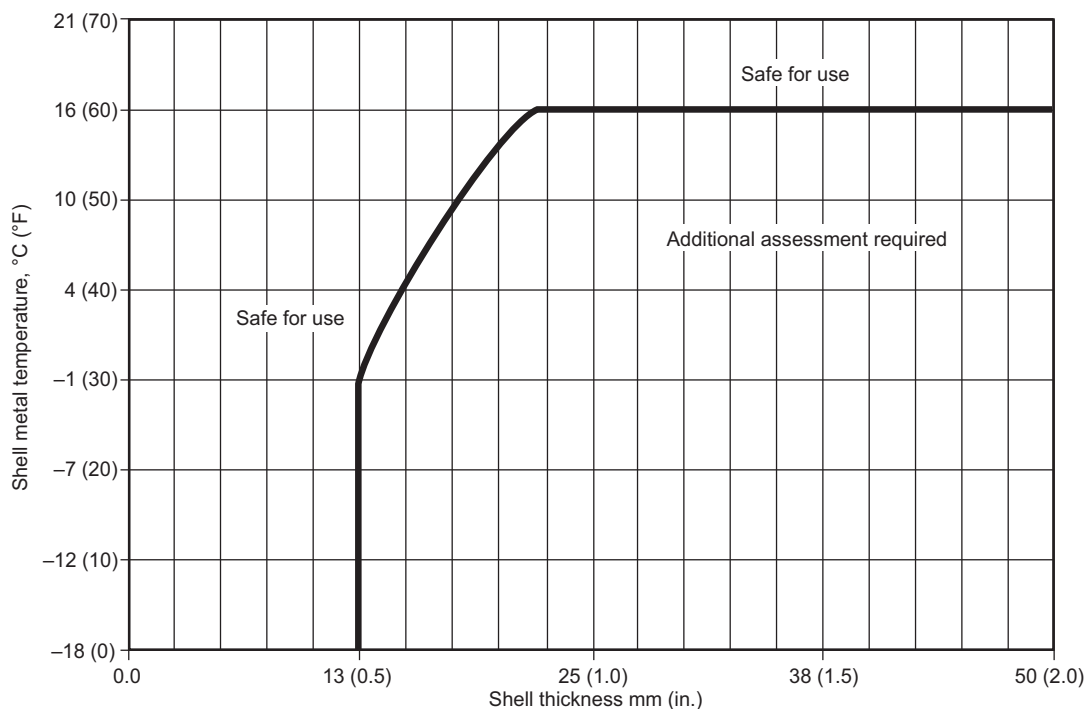
5.3.5 Step 4—If a tank shell thickness is no greater than 13 mm (0.5 in.), the risk of failure due to brittle fracture is minimal, provided that an evaluation for suitability of service in accordance with Section 4 has been performed. The original nominal thickness for the thickest tank shell plate shall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