Inspection Practices for Atmospheric and Low-pressure Storage Tanks

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Contents

Figures

Tables

Inspection Practices for Atmospheric and Low-pressure Storage Tanks

1 Scope

This document provides useful information and recommended practices for the maintenance and inspection of atmospheric and low-pressure storage tanks. Although these maintenance and inspection guidelines may apply to other types of tanks, these practices are intended primarily for existing tanks that were designed and constructed to API aboveground storage tank standards or specifications, as referenced in 2.2.

This document addresses the following:

a) descriptions and illustrations of the various types of storage tanks;

b) new tank construction standards;

c) maintenance practices;

d) reasons for inspection;

e) causes of deterioration;

f) frequency of inspection;

g) methods of inspection;

h) inspection of repairs;

i) preparation of records and reports;

j) safe and efficient operation;

k) leak prevention methods.

This recommended practice is intended to supplement API 653 (applicable for all tanks) and API 12R1 (as applicable for the API 12 series tanks storing production liquids) that provide minimum requirements for maintaining the integrity of storage tanks after they have been placed in service.

2 Normative References

2.1 Codes, Standards, and Related Publications

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 Standard 653, *Tank Inspection, Repair, Alteration, and Reconstruction*

2.2 Other References

The following codes and standards are cited in the text of this recommended practice or included in the knowledge base to develop this document. Familiarity with these documents is suggested as they provide additional information pertaining to the inspection and repair of aboveground storage tanks.

API Standard 12A, *Specification for Oil Storage Tanks with Riveted Shells* (withdrawn)

API Specification 12B, *Specification for Bolted Tanks for Storage of Production Liquids*

API Standard 12C, *Specification for Welded Oil Storage Tanks* (withdrawn)

API Specification 12D, *Specification for Field-welded Tanks for Storage of Production Liquids*

API Standard 12E, *Specification for Wooden Production Tanks* (withdrawn)

API Specification 12F, *Specification for Shop-welded Tanks for Storage of Production Liquids*

API Specification 12P, *Specification for Fiberglass Reinforced Plastic Tanks*

API Standard 12R1, *Installation, Operation, Maintenance, Inspection, and Repair of Tanks in Production Service*

API *Manual of Petroleum Measurement Standards* (*MPMS*) Chapter 2, *Tank Calibration*

API *MPMS* Chapter 19.2, *Evaporative Loss from Floating-roof Tanks*

API 510, *Pressure Vessel Inspection Code: In-service Inspection, Rating, Repair, and Alteration*

API 570, *Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems*

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

API Recommended Practice 572, *Inspection Practices for Pressure Vessels*

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

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

API Recommended Practice 580, *Elements of a Risk-Based Inspection Program*

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

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

API Standard 598, *Valve Inspection and Testing*

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

API Standard 625, *Tank Systems for Refrigerated Liquefied Gas Storage*

API Standard 650, *Welded Tanks for Oil Storage*, 13th Edition

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

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

API Technical Report 654, *Aboveground Storage Tank Caulking or Sealing the Bottom Edge Projection to the Foundation*

API Technical Report 655, *Vapor Corrosion Inhibitors for Storage Tanks*

API Bulletin 939-E, *Identification, Repair, and Mitigation of Cracking of Steel Equipment in Fuel Ethanol Service*

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

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

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

API Standard 2350, *Overfill Prevention for Storage Tanks in Petroleum Facilities*

API Standard 2610, *Design, Construction, Operation, Maintenance, and Inspection of Terminal and Tank Facilities*

ACI 376-11[1], *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases and Commentary*

AISC [2], *Steel Construction Manual*

ASME *Boiler and Pressure Vessel Code* (*BPVC*) [3], *Section V: Nondestructive Examination*

ASME *BPVC*, *Section VIII: Rules for the Construction of Pressure Vessels*

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

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

ASNT CP-189 [4], *Standard for Qualification and Certification of Nondestructive Testing Personnel*

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

ASTM D3359 [5], *Standard Test Methods for Rating Adhesion by Tape Test*

EEMUA 159 [6], *Above ground storage flat bottom storage tanks: A guide to inspection, maintenance and repair*

NFPA 11 [7], *Flammable Standard for Low-, Medium-, and High-Expansion Foam*

NFPA 30, *Flammable and Combustible Liquids Code*

OSHA [8], 29 *Code of Federal Regulations* (*CFR*) Part 1910.23, *Ladders*

OSHA, 20 *CFR* Subpart D, *Walking-Working Surfaces*

OSHA, 29 *CFR* Part 1910.106, *Flammable Liquids*

OSHA, 29 *CFR* Part 1910.146, *Permit-required Confined Spaces*

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1 American Concrete Institute, 38800 Country Club Drive, Farmington Hills, Michigan 48331, www.concrete.org.

2 American Institute of Steel Construction, 130 East Randolph, Suite 2000, Chicago, Illinois 60601, www.aisc.org.

3 ASME International, Two Park Avenue, New York, New York 10016, www.asme.org.

4 American Society for Nondestructive Testing, 1201 Dublin Road, Suite G04, Columbus, Ohio 43215, www.asnt.org.

5 ASTM International, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania 19428, www.astm.org.

6 Engineering Equipment and Materials Users Association, Leytonstone House, 3 Hanbury Drive, London, E11 1GA, United Kingdom, www.eemua.org.

7 National Fire Protection Association, 1 Batterymarch Park, Quincy, Massachusetts 02169, www.nfpa.org.

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

STI SP001 [9], *Standard for Inspection of Aboveground Storage Tanks*

UL 142 [10], *Standard for Safety Steel Aboveground Tanks for Flammable and Combustible Liquids*

US EPA AP-42 [11], *Compilation of Air Emissions Factors from Stationary Sources*

3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

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

3.1.1
alteration
Any work on a tank that changes its physical dimensions or configuration.

3.1.2
atmospheric pressure
When referring to vertical tanks, the term "atmospheric pressure" usually means tanks designed to API 650, although API 620 uses the term "atmospheric pressure" to describe tanks designed to withstand an internal pressure not exceeding the weight of the roof plates. API 650 also provides for rules to design tanks for "higher internal pressure" up to 2.5 psi (18 kPa). API 653 uses the generic meaning for atmospheric pressure to describe tanks designed to withstand an internal pressure up to, but not exceeding, 2.5 psi (18 kPa) gauge.

3.1.3
authorized inspection agency
Any one of the following:

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

b) the inspection organization of an insurance company that 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 their equipment and not for aboveground storage tanks intended for sale or resale;

d) an independent organization or individual that is 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.

3.1.4
authorized inspector
An employee of an authorized inspection agency who is qualified and certified to perform inspections under API 653; whenever the term "inspector" is used in API 575, it refers to an authorized aboveground API 653 inspector.

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[9] Steel Tank Institute/Steel Plate Fabricators Association (STI/SPFA), 944 Donata Court, Lake Zurich, Illinois 60047, www.steeltank.com.

[10] Underwriters Laboratories, 333 Pfingsten Road, Northbrook, Illinois 60062, www.ul.com.

[11] U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue NW, Washington, DC 20004, www.epa.gov.

3.1.5
condition monitoring location
CML
Designated areas on tanks where periodic examinations are conducted to directly assess the condition of the tank. Condition monitoring locations (CMLs) may contain one or more examination points and utilize multiple inspection techniques that are based on the predicted damage mechanism to give the highest probability of detection. CMLs can be a single small area on a tank (e.g. a 2-in. diameter spot or a plane through a section of a nozzle) where recording points exist in all four quadrants of the plane.

NOTE CMLs include, but are not limited to, thickness measurement locations.

3.1.6
corrosion allowance
Additional material thickness available to allow for metal loss during the service life of the tank component.

3.1.7
corrosion rate
The total metal loss divided by the period of time over which the metal loss occurred.

3.1.8
corrosion specialist
A person, acceptable to the owner-operator, who has knowledge and experience in corrosion damage mechanisms, metallurgy, materials selection, and corrosion monitoring techniques.

3.1.9
corrosion under insulation
CUI
External corrosion of materials of tanks and structural components resulting from water trapped under insulation; external chloride stress corrosion cracking (SCC) of austenitic and duplex stainless steel under insulation is also classified as corrosion under insulation (CUI) damage.

3.1.10
damage mechanism
Any type of deterioration encountered in the refining and chemical process industry that can result in flaws or defects that can affect the integrity of tanks (e.g. corrosion, cracking, erosion, dents, and other mechanical, physical, or chemical impacts); see API 571 for a comprehensive list and description of damage mechanisms.

3.1.11
defect
An imperfection whose type or size exceeds the applicable acceptance criteria and is therefore rejectable.

3.1.12
documentation
Records containing descriptions of specific tank design, personnel training, inspection plans, inspection results, nondestructive examination (NDE), repair, alteration, operating heights or capacities, fitness-for-service (FFS) assessments, procedures for undertaking these activities, or any other information pertinent to maintaining the integrity and reliability of the tank.

3.1.13
examinations
A process by which an examiner or inspector investigates a component of the tank using NDE in accordance with approved NDE procedures (e.g. inspection of a CML, quality control of repair areas).

3.1.14
examiner
A person who assists the inspector by performing specific 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.

3.1.15
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.

3.1.16
fitness-for-service assessment
FFS 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.

3.1.17
general corrosion
Corrosion that is distributed more or less uniformly over the surface of the metal, as opposed to localized corrosion.

3.1.18
heat-affected zone
The portion of the base metal whose mechanical properties or microstructure have been altered by the heat of welding or thermal cutting.

3.1.19
hydrostatic pressure
The pressure exerted by a fluid at equilibrium at a given point within the fluid, due to the force of gravity. Hydrostatic pressure increases in proportion to the depth measured from the surface because of the increasing weight of the fluid exerting downward force from above.

3.1.20
indications
A response or evidence resulting from the application of NDE that may be nonrelevant, flawed, or defective upon further analysis.

3.1.21
in service
Designates a tank that has been placed in operation as opposed to new construction prior to being placed in service or retired tanks. A tank not in operation because of a process outage is still considered an in-service tank.

NOTE Does not include tanks that are still under construction or in transport to the site prior to being placed in operation or tanks that have been decommissioned. It does include tanks that are temporarily out of service but still in place in an operating site. A stage in the service life of a tank between installation and being decommissioned.

3.1.22
inspection
The external, internal, or in-service evaluation (or any combination of the three) of the condition of a tank conducted by the authorized inspector or their designee in accordance with API 653.

3.1.23
inspection plan
A strategy defining how and when a tank or its devices will be inspected, repaired, and/or maintained.

3.1.24
inspector
A shortened title for an authorized tank inspector qualified and certified in accordance with API 653.

3.1.25
internal inspection
A formal, complete inspection, as supervised by an authorized inspector, of all accessible internal tank surfaces.

NOTE Refer to API 653 definition for this term when referenced in API 575.

3.1.26
jurisdiction
A legally constituted governmental administration that may adopt rules relating to tanks.

3.1.27
localized corrosion
Corrosion that is largely confined to a limited or isolated area of the metal surface of a tank.

3.1.28
magnetic flux leakage
MFL
An electromagnetic scanning technology for tank bottoms also known as MFE (magnetic flux exclusion).

3.1.29
minimum acceptable thickness
The lowest thickness at which a tank component should operate, as determined by the parameters in the applicable tank design standard (such as API 650, API 653, etc.), the FFS principles in API 579-1/ASME FFS-1, or other appropriate engineering analysis.

3.1.30
owner-operator
The legal entity having control of and/or responsibility for the operation and maintenance of an existing storage tank.

3.1.31
procedures
A document that specifies or describes how an activity is to be performed. It may include methods to be employed, equipment or materials to be used, qualifications of personnel involved, and sequence of work.

3.1.32
product-side
The side of the tank that is in contact with the stored liquid.

3.1.33
reconstruction
Any work necessary to reassemble a tank that has been dismantled and relocated to a new site.

3.1.34
reconstruction organization
The organization having assigned responsibility by the owner-operator to design and/or reconstruct a tank.

3.1.35
release prevention barrier
RPB
The second bottom of double steel bottom tanks, synthetic materials, clay liners, and all other barriers or combination of barriers placed under an aboveground storage tank, which have the following functions:

a) preventing the escape of contaminated material;

b) containing or channeling released material for leak detection.

NOTE See nonmandatory Annex I of API 650.

3.1.36
repair
Work necessary to maintain or restore a tank to a condition suitable for safe operation. Repairs include both major repairs and repairs that are not major repairs. Examples of repairs include the following:

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

b) releveling 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.

3.1.37
risk-based inspection
RBI
A risk assessment and management process that is focused on loss of containment of equipment in facilities due to material deterioration. These risks are managed primarily through equipment inspection.

3.1.38
soil-side
The side of the tank bottom that is in contact with the ground.

3.1.39
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.

3.1.40
temporary repairs
Repairs made to storage tanks to restore sufficient integrity to continue safe operation until permanent repairs are conducted.

3.1.41
vapor corrosion inhibitor
VCI
volatile corrosion inhibitor
Chemical substances that slowly release a corrosion-preventative compound into an enclosed airspace, effectively protecting exposed metal surfaces.

3.2 Acronyms and Abbreviations

AST aboveground storage tank

BS&W bottom sediment and water

CML condition monitoring location

CUI corrosion under insulation

FFS fitness-for-service

MFL magnetic flux leakage

MIC microbial induced corrosion

NDE nondestructive examination

RBI risk-based inspection

RPB release prevention barrier

SCC stress corrosion cracking

UT ultrasonic thickness

VCI vapor corrosion inhibitor

WFMT wet fluorescent magnetic particle testing

4 Types of Storage Tanks

4.1 General

4.1.1 Tank Design and Materials

Storage tanks are used to store fluids, such as crude oil, intermediate and refined products, gas, chemicals, waste products, water, and water/product mixtures. Aboveground storage tank minimum requirements for design are covered within documents referenced in 2.2. Important factors, such as the volatility of the stored fluid and the desired storage pressure and temperature, result in tanks being built of various types, sizes, and materials of construction. In this document, only atmospheric and low-pressure storage tanks are considered. Guidelines for inspection of pressure vessels operating at pressures greater than 15 psi (103 kPa) gauge are covered in API 572.

There are two types of tanks commonly found in industry: fixed roof and floating roofs. Fixed-roof tanks can be constructed out of carbon steel, alloy steel, aluminum, or other metals. In addition to these materials, tanks can be constructed out of nonmetallic materials such as concrete, reinforced thermoset plastics, and wood (API 12E). Floating-roof tanks are commonly made out of carbon steel but can also be made of other alloys, as well as composite materials. Floating roofs can be characterized as full contact floating roofs, or partial contact floating roofs, depending on the amount of their bottom side surfaces that is in direct contact with the product stored. Atmospheric tanks are generally welded but can also be riveted (API 12A) or bolted (API 12B).

4.1.2 Storage Tanks with Linings, Cathodic Protection, and/or Vapor Corrosion Inhibitors

Where internal corrosion is experienced or expected, tanks can be lined with a variety of corrosion-resistant materials, such as coatings of epoxy or vinyl ester, fiberglass, poured or sprayed concrete, alloy steel, aluminum, rubber, lead, synthetics such as high-density polyethylene or other synthetic rubber, and glass.

See API 652 for provisions for the application of some types of tank bottom linings to both existing and new storage tanks.

Cathodic protection systems are often provided for control of external bottom corrosion and, combined with internal linings, may also be used to protect tank bottoms internally. See API 651 for design, maintenance, and monitoring recommendations for such systems.

As an alternative or supplement to cathodic protection, some utilize vapor corrosion inhibitors (VCIs) to protect the underside of the tank bottom from corrosion. See API 655 for information regarding the design, use, and maintenance of VCIs for under-bottom AST corrosion protection.

4.1.3 Storage Tanks with Passive Leak Detection Systems

Leak detection systems are installed for early awareness of a potential leak. API 650—Annex I provides design guidelines for leak detection and subgrade protection. Reference also API 306, API 307, API 315, API 322, API 323, API 325, API 340, and API 341 for additional information on leak detection systems for storage tanks and dike containment areas.

4.1.4 Storage Tanks with Optional Auxiliary Equipment

Storage tanks are provided with some of the following auxiliary equipment, such as liquid-level gauges, high- and low-level alarms, and other overfill prevention systems (see API 2350), pressure-relieving devices (see API 2000), vacuum venting devices, emergency vents, gauging hatches, roof drain systems, flame arrestors, fire protection systems (see NFPA 11), and mixing devices.

Stairways, ladders, platforms, handrails, piping connections and valves, manholes, electric grounding connections (as required), and cathodic protection systems and VCI systems are considered examples of storage tank auxiliary equipment.

Insulation may also be present to maintain product temperature. Insulation can vary from externally jacketed panel systems to sprayed-on foam systems to loose-fill systems in double-wall tank construction.

Heating systems are a type of auxiliary equipment that a storage tank may have. This may include heating coils, steam tracing, electrical tracing, and a bundle installed in a large nozzle.

Agitators are a type of axillary equipment that a storage tank may have. This may include a single or multiple agitators installed through large nozzles similar to a bundle.

Inspection and failure of auxiliary equipment are covered in 5.4.

4.2 Atmospheric Storage Tanks

4.2.1 Construction, Materials, and Design Standards

Atmospheric storage tanks are designed to operate with internal gas and vapor spaces at pressures close to atmospheric pressure. Such tanks are usually constructed of carbon steel, alloy steel, aluminum, or other metals, depending on service. Additionally, some tanks are constructed of nonmetallic materials, such as reinforced concrete, reinforced thermoset plastics, and wood. Some wooden tanks constructed to API 12E are still in service. Atmospheric storage tanks are generally welded. Some riveted tanks constructed to API 12A and some bolted tanks constructed to API 12B can also be found still in service. Information for the construction of atmospheric storage tanks is given in API 12A (withdrawn), API 12B, API 12C (the predecessor to API 650 and now withdrawn), API 12D, API 12E (withdrawn), API 12F, API 650, API 620, and API 2000. API 625 covers the selection, design, and construction of tank systems for refrigerated liquefied gas storage on land. API 653 provides information pertaining to requirements for inspection, repair, alteration, and reconstruction of aboveground storage tanks.

4.2.2 Use of Atmospheric Storage Tanks

Atmospheric storage tanks in the petroleum industry are normally used for fluids having a true vapor pressure that is less than atmospheric pressure. Vapor pressure is the pressure on the surface of a confined liquid caused by the vapors of that liquid. Vapor pressure increases with increasing temperature. Crude oil, heavy oils, gas oils, furnace oils, naphtha, gasoline, and nonvolatile chemicals are usually stored in atmospheric storage tanks. Many of these tanks are protected by pressure/vacuum vents that limit the pressure difference between the tank vapor space and the outside atmosphere to a few ounces per square inch.

Non-petroleum industry uses of atmospheric tanks include storage of a variety of chemicals and other substances operated in closed-loop systems not vented to atmosphere and with pressure control and relief devices as required. These tanks may be designed and operated as low-pressure storage tanks per API 620. See 4.3 for additional information on tanks operated at low pressure.

Additional uses for atmospheric storage tanks can include the storage of liquid (both hydrocarbon and non-hydrocarbon) in horizontal tanks, and process liquids or granular solids in skirt-supported or column-supported tanks with elevated cone bottoms (non-flat bottom), and the storage of process water/liquids in open-top tanks.

4.2.3 Types of Atmospheric Storage Tank Roofs

4.2.3.1 Fixed Cone Roof Tanks

The most common type of atmospheric storage tank is the fixed cone roof tank (see Figure 1). Fixed cone roof tanks may typically be up to 300 ft (91.5 m) in diameter and 64 ft (19.5 m) in height, although larger-diameter tanks have been built. These roofs are normally supported by internal structural rafters, girders, and columns but can be fully self-supporting in smaller diameters [typically 60 ft (18.3 m) diameter or less]. Self-supporting aluminum dome roofs (e.g. geodesic dome roofs) may be applied to most diameter tanks without the need for internal supporting columns.

A steel cone roof may include a “frangible joint” (weak roof-to-shell joint) which is of benefit to allow emergency release of internal pressure, while avoiding shell uplift and potential failure of the bottom-to-shell joint. The mechanism allowing roof-to-shell joint failure is the shell and top angle joint buckling under compression as the roof rotates during uplift, leading to the tearing of the peripheral weak seam weld.

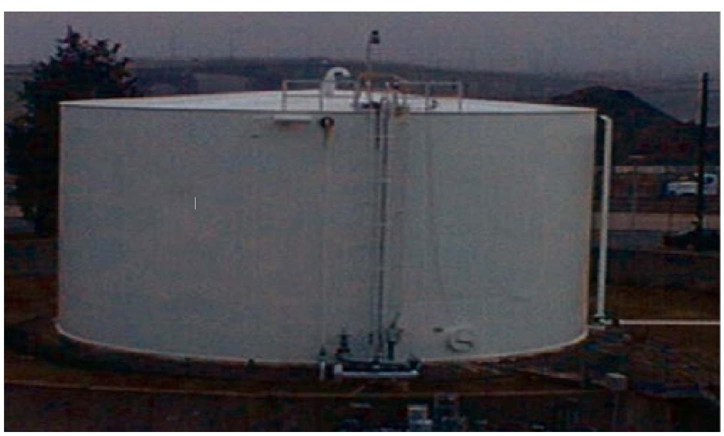


Figure 1—Fixed Cone Roof Tank

4.2.3.2 Domed Roof Tanks

The self-supporting aluminum dome roof tank (see Figure 2) and the umbrella roof tank (see Figure 3) are variations of the fixed-roof tank. The steel dome roofs are clear span self-supporting from the top of the tank shell without columns and are often used with pressurized tanks.

Figure 2—Self-supporting Dome Roof Tank

4.2.3.3 Umbrella Roof

The umbrella roof has radially arched segmental plates with integral framing support members (usually without internal support columns).

Figure 3—Umbrella Roof Tank

4.2.3.4 Geodesic Dome Roof

The geodesic dome is of aluminum construction and is self-supported (see Figure 4). The addition of the geodesic dome can reduce product vapor loss or eliminate the need to drain rainwater from the roof. The geodesic dome can be installed at new construction or retroactively over existing external floating-roof tanks. Minimum requirements for the geodesic dome roof are defined in API 650—Annex G for use as a fixed roof (with or without a floating roof). The construction is clear span and self-supported from the rim of the tank. An alternative design in API 650—Annex G permits transfer of the radial forces to an “external tension ring” (typically steel) with fixed dome supports, where the top of the shell/wind-girder is additionally reinforced to retain the radial tension/compression forces from the dome in combination with wind acting on the shell as an open-top tank. The latter design results in reduced aluminum dome material (eliminating the aluminum integral tension ring), offsetting the additional steel and increased tank design requirements. The external tension ring option usually becomes efficient for new tanks at diameter of 200’ or greater and is typically the only option for tanks exceeding 300’ in diameter, except for true “geodesic” designs that have minimal radial force transfer.

Figure 4—Self-supporting Aluminum (Geodesic) Dome Roof Tank

4.2.4 Types of Floating Roofs for Atmospheric Storage

4.2.4.1 Open-top External Floating-roof Tanks

4.2.4.1.1 General

Tanks without a fixed roof are referred to as open-top or external floating-roof tanks. The external floating-roof tank is designed to minimize filling and breathing losses by eliminating or minimizing the vapor space above the stored liquid. The shell and bottom of this type of tank are similar to those of the fixed-roof tanks, but in this case, the roof is designed to float on the surface of the stored liquid. In instances where the shell is not braced to resist buckling from the wind, a wind-girder will be included as part of the shell design.

4.2.4.1.2 Steel Pan Floating Roof

The steel pan floating roof is a single steel deck designs without annular pontoons as shown in Figure 5. This external floating roof type is no longer permitted under API 650—Annex C. Such roofs have no reserve buoyancy and are susceptible to sinking in service.

Figure 5—Externally Stiffened Pan-type Floating-roof Tank

Caution—The externally stiffened pan-type floating roof is no longer allowed to be constructed per API 650—Annex C, although many still remain in use.

4.2.4.1.3 Variations

Annular-pontoon and double-deck roofs are shown in Figure 6 and Figure 7, respectively.

External floating roofs are designed in accordance with API 650—Annex C. A "domed external floating roof" is a type designed as an external floating roof, except it is covered with a clear span aluminum dome roof and vented in accordance with API 650—Annex H. These domed external floating-roof tanks are considered internal floating roofs for tank venting and confined space entry purposes; however, the floating roof is the emission control device and the fixed aluminum dome modifies emission factors applied to liquid surface temperature, seals, and deck fittings.

Refer to API *MPMS* Ch. 19.2 *Evaporative Loss from Floating-roof Tanks* for further means to evaluate evaporation/emission loss for various types of floating-roof tanks and their respective fittings.

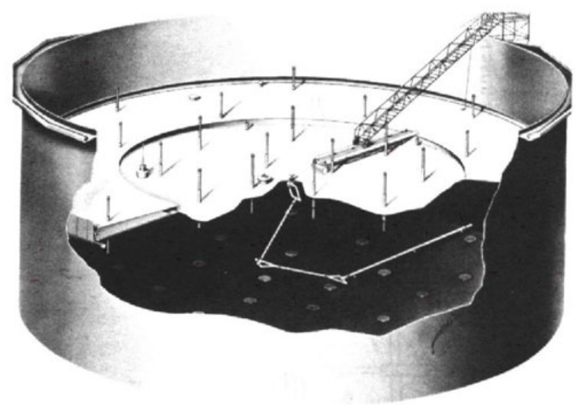


Figure 6—Annular-pontoon Floating-roof Tank

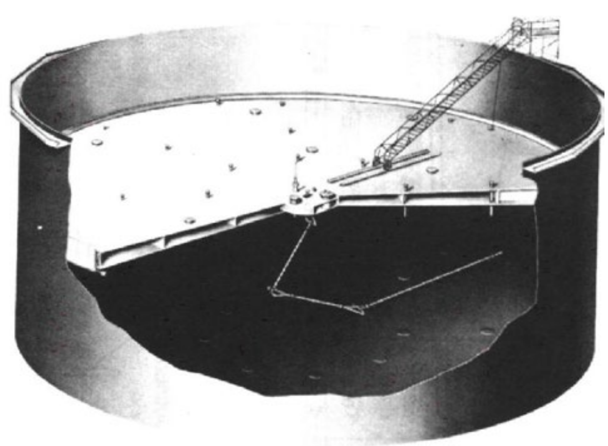


Figure 7—Double-deck Floating-roof Tank

4.2.4.1.4 Floating-roof Seals

Cross-sectional sketches showing important features of floating roofs are shown in Figure 8. Floating-roof sealing systems are used to seal the space between the tank wall and the floating roof. When a floating roof has two such devices, one mounted above the other the lower seal is the primary seal and the upper seal is the secondary seal. Primary seals may be mechanical shoe, liquid mounted, or vapor mounted. Secondary seals are rim mounted above any type of primary seal. The seal details are similar in description for external floating-roof and internal floating-roof types, but default emission losses are unique to the floating-roof design type. API 650—Annex C external floating-roof seals and fittings will be deeper and based on results of regulatory accepted API testing have reduced default emission factors compared to API 650—Annex H internal floating-roof type seals and fittings. It is important to electrically bond the seal to ground with “grounding” shunts, cables, or other means.

4.2.4.1.5 Liquid-mounted Seals

A liquid-mounted rim seal is a resilient foam-filled or liquid-filled primary rim seal mounted in a position resulting in the bottom of the seal being normally in contact with the stored liquid surface. This seal may be a flexible foam or liquid contained in a coated fabric envelope.

4.2.4.1.6 Vapor-mounted Seals

A vapor-mounted rim seal is a peripheral seal positioned such that it does not normally contact the surface of the stored liquid. Vapor-mounted peripheral seals may include, but are not limited to, resilient foam-filled seals (similar in design to liquid-mounted seals) and flexible-wiper seals. Flexible-wiper seal means a rim seal using a blade or tip of a flexible material (such as extruded rubber or synthetic rubber; see Figure 12) with or without a reinforcing cloth or mesh.

4.2.4.1.7 Mechanical Shoe

This type of seal consists of a series of sheets (shoes) that are overlapped or joined together to form a ring and held against the tank wall by springs (or by counterweights in older designs) or other tensioning system, with a flexible vapor membrane attached between the shoe and the floating-roof outer rim. Typical examples of this type of floating-roof seal are shown in Figures 9 and 11.

4.2.4.1.8 Wiper Seals

Wiper seals are used as secondary seals. These are compression plates with wiper tips or simply an elastomeric wiper that spans the space between the floating roof and tank shell.

Figure 13 illustrates various examples of seals mounted on internal floating roofs.

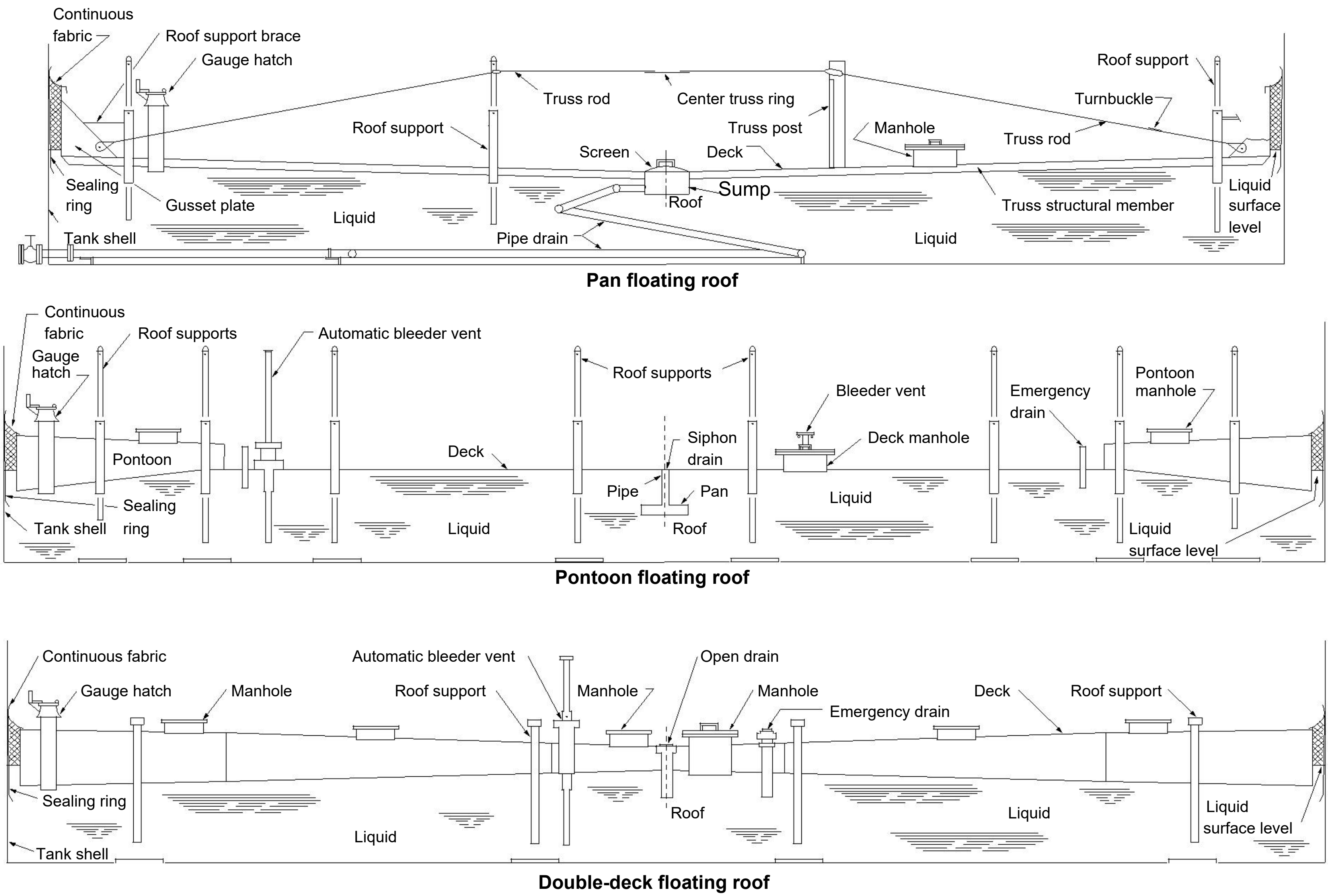


Figure 8—Cross-section Sketches of External Floating-roof Tanks Showing the Most Important Features

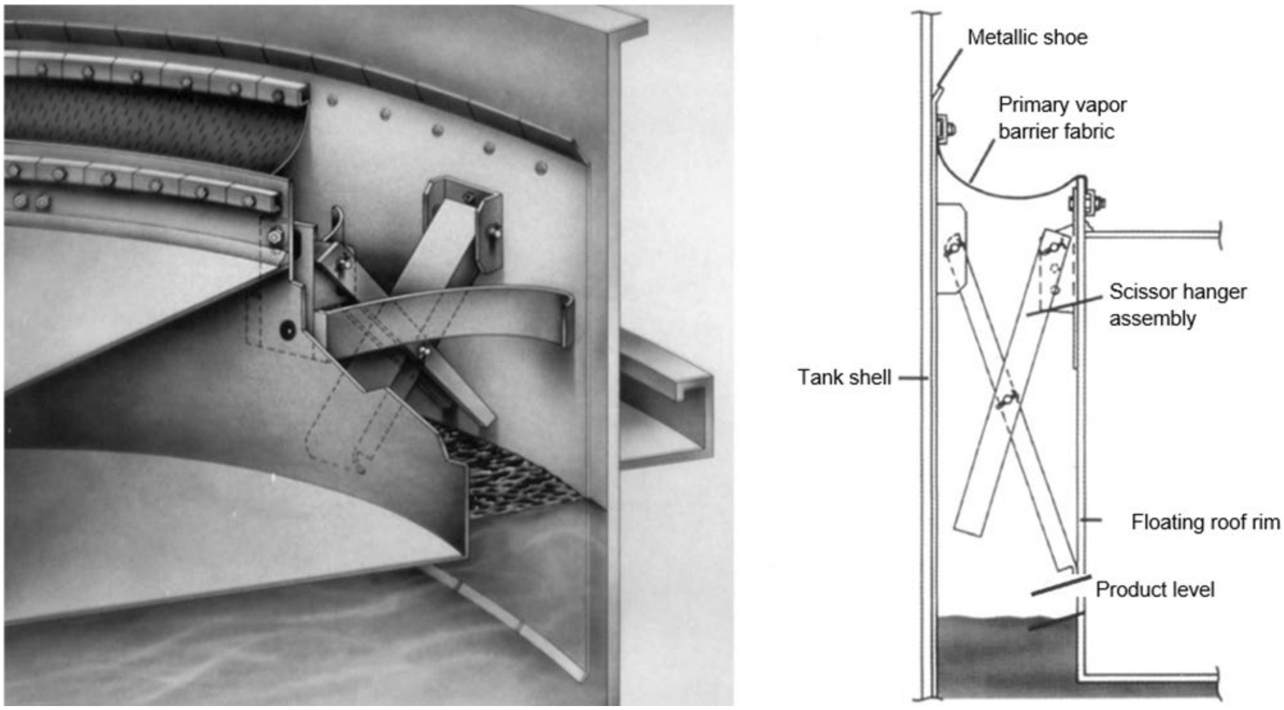


Figure 9—Floating-roof Shoe Seal

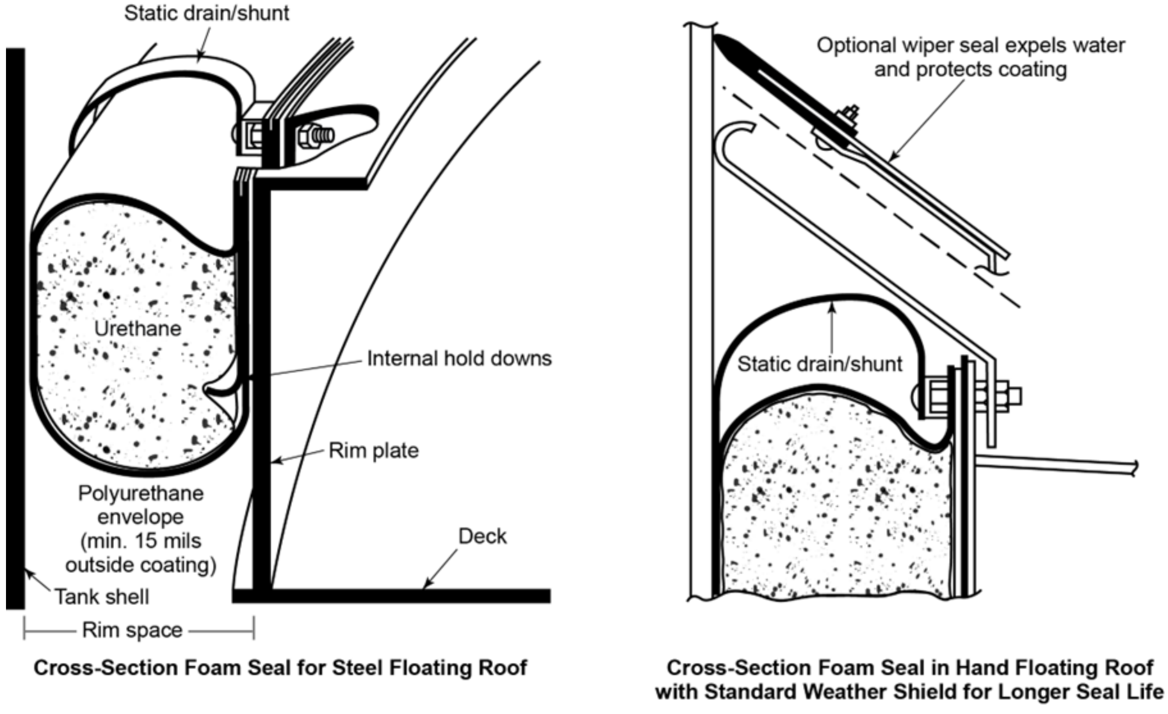


Figure 10—Floating-roof Log Seal

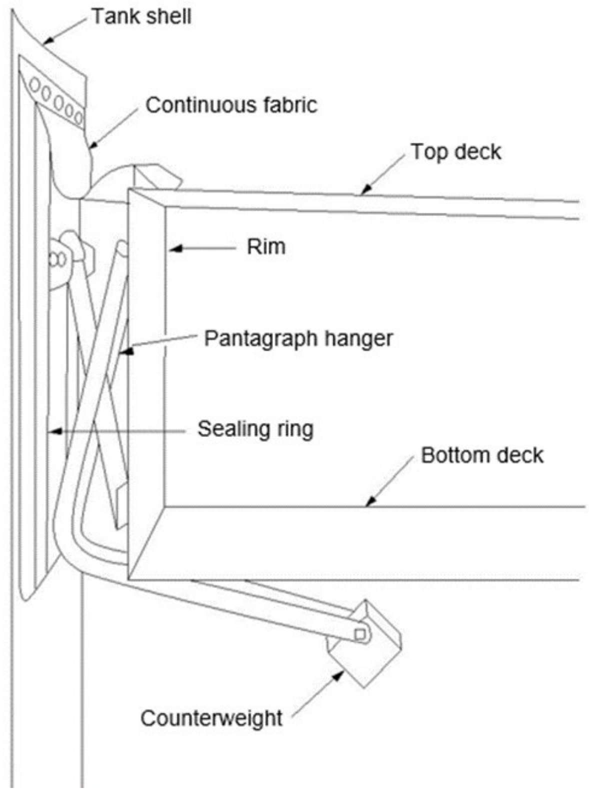


Figure 11—Floating Roof Using Counterweights to Maintain Seal

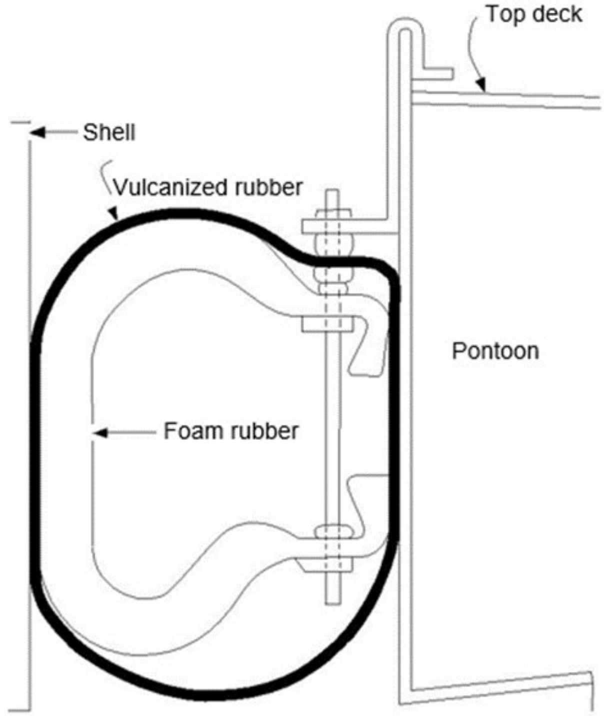


Figure 12—Floating Roof Using Resilient Tube-type Seal

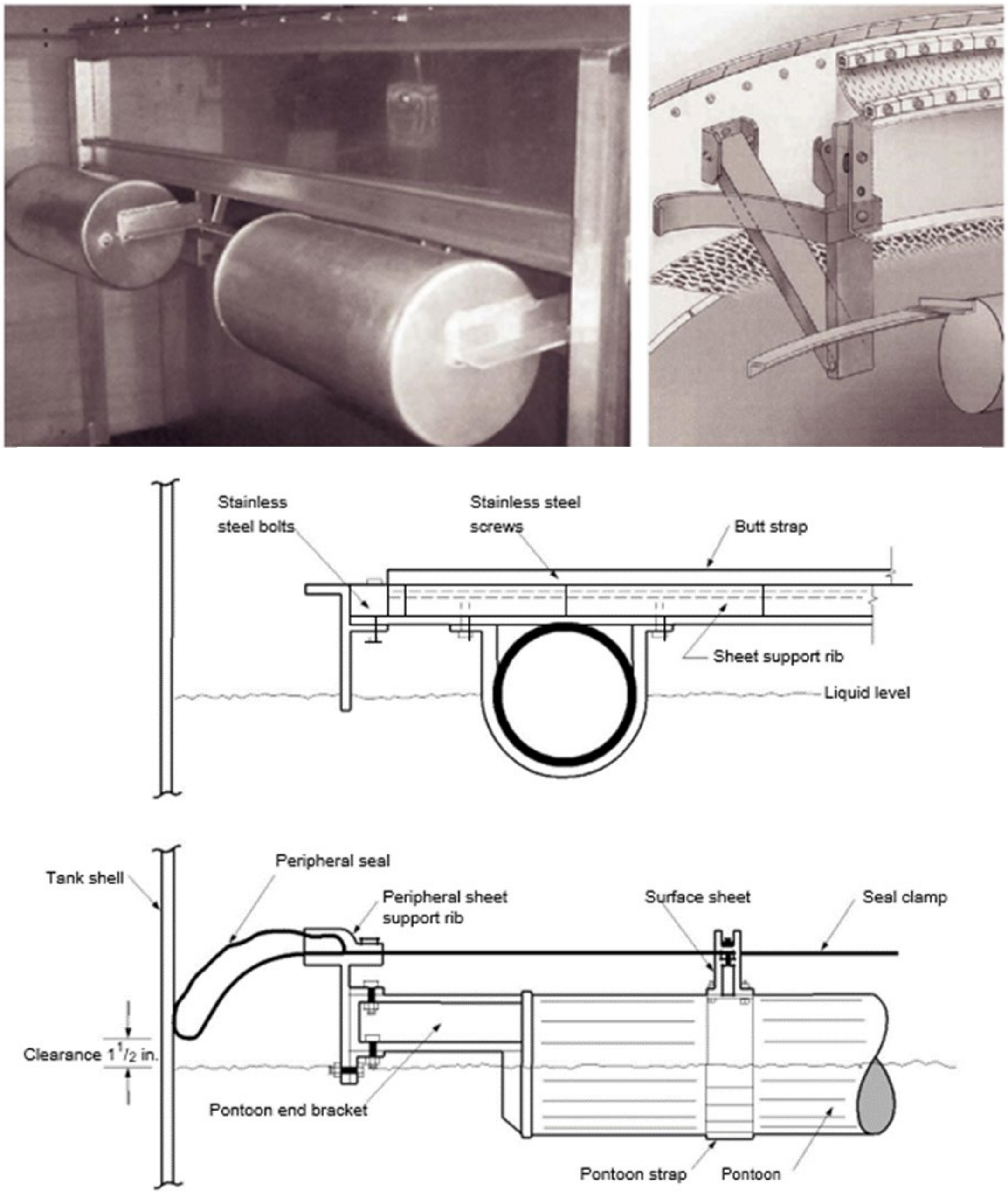
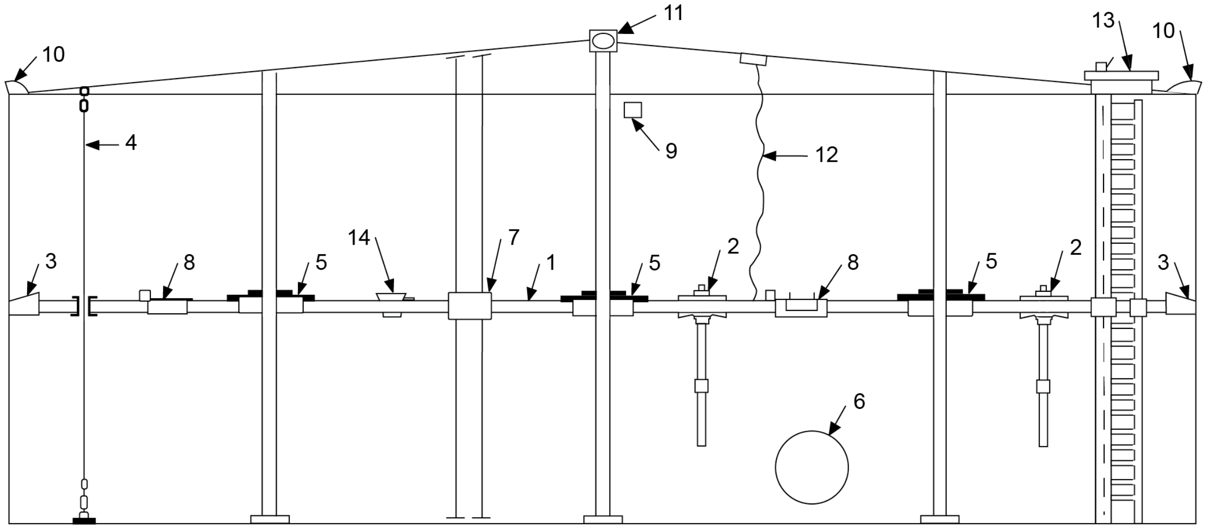


Figure 13—Typical Arrangement for Metallic Float Internal Floating-roof Seals

4.2.4.2 Internal Floating-roof Tanks

Another type of tank has both a fixed roof and an internal floating roof. Internal floating roofs can be of full contact or non-contact design. The fixed roof is usually a supported cone or dome (of steel or aluminum). The internal floating roof (shown in Figure 14) can be constructed of steel, aluminum, or other material. An existing external floating roof can be covered with a steel cone roof, or geodesic dome. When the external floating roof is covered, it functions much as it did as an external floating roof. Modifications may be made to the roof drain system as the roof is no longer exposed to the elements and many owner-operators choose to remove or modify the rolling access ladder. Such tanks are usually built to alleviate weather-related concerns about the flotation of an external floating roof, to reduce vapor emissions, or to prevent product contamination. An existing fixed-roof tank often can be modified by the installation of an internal floating roof. Cone roofs with an internal floating roof supported by cables suspended from the fixed cone roof are another common design that is being used (see Figure 15). Internal floating roofs are also made of aluminum, and these can be of the “skin and pontoon” design where the floating roof rests on the pontoons that are immersed in the product or these may also be of full contact design, similar to a steel internal floating roof.



Key

1	deck	8	vacuum relief device
2	support legs	9	overflow vent
3	seal	10	peripheral roof vent
4	anti-rotation device	11	center roof vent
5	column negotiating device	12	antistatic grounding
6	manway	13	roof hatch
7	gauge floatwell	14	gauge funnel

Figure 14—Typical Internal Floating-roof Components

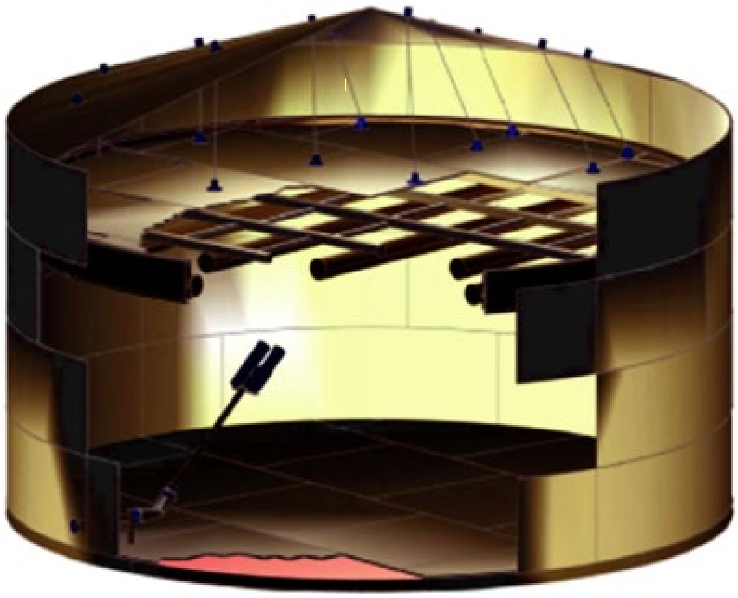


Figure 15—Cable-supported Internal Floating-roof Tank

API 650—Annex H classifies internal floating roofs into the following types.

a) Metallic pan internal floating roofs have a peripheral rim above the liquid for buoyancy. These roofs are in full contact with the liquid surface and are typically constructed of steel. See Figure 5. **Caution—These are no longer permitted for construction, but many are still in use. These types have no closed buoyancy compartments and are *not* considered a floating roof for purposes of AST spacing in accordance with NFPA 30.**

b) Metallic open-top bulk-headed internal floating roofs have peripheral open-top bulk-headed compartments for buoyancy. These roofs are in full contact with the liquid surface and are typically constructed of steel. These types have no closed buoyancy compartments and are *not* considered a floating roof for purposes of AST spacing in accordance with NFPA 30.

c) Metallic pontoon internal floating roofs have peripheral closed-top bulk-headed compartments for buoyancy. These roofs are in full contact with the liquid surface and are typically constructed of steel.

d) Metallic double-deck internal floating roofs have continuous closed top and bottom decks that contain bulk-headed compartments for buoyancy. These roofs are in full contact with the liquid surface and are typically constructed of steel.

e) Metallic internal floating roofs on floats have their deck above the liquid, supported by closed pontoon compartments for buoyancy. These roof decks are not in full contact with the liquid surface and are typically constructed of aluminum alloys or stainless steel.

f) Metallic sandwich-panel/composite internal floating roofs have metallic composite material panel modules for buoyancy compartments. Panel modules may include a honeycomb or closed cell foam core; however, cell walls within the panel module are not considered “compartments” for purposes of inspection and design buoyancy requirements. These roofs are in full contact with the liquid surface and are typically constructed of aluminum alloys or purchaser-approved composite materials.

g) Hybrid internal floating roofs shall, upon agreement between the purchaser and the manufacturer, be a design combination of roof types having bulk-headed compartments with closed-top perimeter pontoon and open-top center compartments for buoyancy. These roofs are in full contact with the liquid surface and are typically constructed of steel.

h) Other roof materials or designs if specified and described in detail by the purchaser.

4.2.5 Vapor Recovery Systems

Vapor recovery systems can be provided on several types of tanks, such as a fixed cone roof (see Figure 1), umbrella roofs (see Figure 3), and vapor dome roofs (see Figure C.9). Adjustment in relief valve settings will be required to accommodate the operating parameters for the vapor recovery system. The tank must be designed for the internal and external (vacuum) pressures with relief vents having operating pressure set to fully open within the design pressure limits of the tank.

4.3 Low-pressure Storage Tanks

4.3.1 Construction, Materials, and Design Standards

Low-pressure storage tanks are those designed to operate with pressures in their gas or vapor spaces exceeding the 2.5 psi (18 kPa) gauge permissible in API 650 but not exceeding the 15 psi (103 kPa) gauge maximum limitation of API 620. These tanks are generally constructed of carbon or alloy steel and are usually welded, although riveted tanks in low-pressure service are still found. Rules for the design and construction of large, welded, low-pressure storage tanks are included in API 620. Venting requirements are covered in API 2000.

API 625 addresses tank systems designed for storing refrigerated liquefied gas. A tank system consists of one or more containers together with various accessories, appurtenances, and insulation. The metal storage containers themselves are addressed in API 620—Annex R for steel containers for refrigerated products from 40 °F (4 °C) to −60 °F (−51 °C) and in API 620—Annex Q for steel containers for −60 °F (−51 °C) to −325 °F (−198 °C). ACI 376 addresses concrete containers for 40 °F (4 °C) to −270 °F (−168 °C).

4.3.2 Use of Low-pressure Storage Tanks

Low-pressure storage tanks are used for the storage of the more volatile fluids having a true vapor pressure exceeding the pressure limits of API 650 but not more than 15 psi (103 kPa) gauge. Light crude oil, gasoline blending stock, light naphtha, pentane, volatile chemicals, liquefied petroleum gas, liquefied natural gas, liquid oxygen, and liquid nitrogen are examples of liquids that should be stored in low-pressure storage tanks.

API 620—Annexes R and Q and ACI 376 provide single-wall and double-wall construction details.

4.3.3 Types of Low-pressure Storage Tanks

Tanks that have cylindrical shells and cone or dome roofs are typically used for pressures less than about 5 psi (34.5 kPa) gauge. Tank bottoms may be flat or have a shape similar to the roof. Hold-down anchorage of the shell is generally required. For pressures above about 5 psi gauge (34.5 kPa) gauge, hemispheroid, spheroid, and noded spheroid tank types are commonly used. Tanks for this application are now typically constructed as spheres. Such tanks are designed to withstand the vapor pressure that may be developed within a tank having no devices or means to change or relieve the internal volume. As with atmospheric storage tanks, these tanks are provided with relief valves to prevent pressures from rising above design values.

Spheres are also constructed for product under pressure in accordance with API 620.

4.3.4 Tank Systems for Refrigerated, Liquefied Gas Storage

API 625—Section 5 defines and describes various storage concepts for refrigerated liquefied gas tank systems. These include single, double, and full containment concepts. Some of these concepts are briefly described as follows.

Single containment—This system incorporates a liquid-tight container and a vapor-tight container. There are several variants to the single containment concept such as the following.

1) Single wall—Single low-temperature steel or concrete tank containing the cold liquid with warm vapor-containing roof, suspended deck with insulation, and external wall insulation. (See API 625—Figure 5.1.)

2) Single wall—Single low-temperature steel or concrete tank containing the cold liquid with low-temperature vapor-containing roof, external roof insulation, and external wall insulation. (See API 625—Figure 5.2.)

3) Double wall—Single low-temperature steel or concrete tank containing the cold liquid with a warm vapor-containing roof, suspended deck with insulation, annular space insulation, and warm vapor-containing outer tank (concrete or steel). (See API 625—Figure 5.3.)

4) Double wall—Single low-temperature steel or concrete tank containing the cold liquid with low-temperature vapor-containing roof, external roof insulation, annular space insulation, and warm vapor-containing outer tank (concrete or steel). (See API 625—Figure 5.4.)

Double containment—An inner tank (low-temperature steel or concrete) containing the cold liquid surrounded by a secondary containment tank of steel or concrete that holds any leaked liquid but not any leaked vapor. There are several variants to the double containment concept such as the following.

— Low-temperature steel or concrete primary liquid container, secondary low-temperature steel or concrete secondary liquid container, suspended deck with insulation, warm vapor-containing roof, and insulation on primary liquid container shell. (See API 625—Figure 5.5.)

Full containment—An inner tank (low-temperature steel or concrete) containing the cold liquid surrounded by a secondary containment tank of steel or concrete that holds any leaked liquid and provides for a controlled release of vapor. There are several variants to the full containment concept as follows.

1) Low-temperature steel or concrete primary liquid container, secondary low-temperature steel or concrete secondary liquid container, suspended deck with insulation, warm vapor-containing roof, and annular space insulation between the liquid containers. (See API 625—Figure 5.7.)

2) Concrete primary liquid container, concrete secondary containment, and concrete roof. (See API 625—Figure 5.10.)

5 Reasons for Inspection and Causes of Deterioration

5.1 Reasons for Inspection

5.1.1 General

The basic reasons for inspection are to determine the physical condition of the tank and to determine the type, rate, and causes of damage mechanisms and associated deterioration. This information should be carefully documented during each inspection (see Section 11 for a list of example documentation). The information and data gained from an inspection contribute to the planning of future inspections, repairs, and replacement and yield a history that should form the basis of good quality permanent inspection records.

5.1.2 Process Safety and Environmental Protection

One of the primary reasons to conduct periodic scheduled inspections is to identify deficiencies that could result in a process safety incident, such as loss of containment, which could lead to fire, toxic exposure, or other environmental hazards. These deficiencies should be addressed as soon as practical through evaluation, further inspection, or repair.

5.1.3 Regulatory Requirements

5.1.3.1 General

In general, regulatory agencies require the compliance with an industry standard or code or adherence to Recognized and Generally Accepted Good Engineering Practices (RAGAGEP) when performing any inspection and repair activities. Many regulatory groups, including the Occupational Safety and Health Administration (OSHA) and the Pipeline and Hazardous Materials Safety Administration (PHMSA) in the United States, require that operating companies follow internal procedures in addition to applicable codes and standards (which is especially important if internal procedures require more than applicable codes and standards).

5.1.3.2 Regulatory

API 653 was developed to provide an industry standard for the inspection of aboveground storage tanks. It has been adopted by a number of regulatory and jurisdictional authorities.

Internal procedures regarding inspection of tanks should encompass the requirements outlined in API 653 to help ensure compliance with many of the regulatory and jurisdictional authorities. Owner-operators should be familiar with the regulatory requirements, including which standards and editions are recognized by their regulatory agencies, as the latest edition of the standard is not always the one referenced.

5.1.3.3 Emissions Control

In the United States, the Environmental Protection Agency has issued a Spill Prevention, Control, and Countermeasure rule that covers most petroleum storage facilities. These regulations allow tank owners and operators to use industry standards and practices to implement and ensure an effective storage tank integrity program. Currently, the most widely recognized tank inspection standards are API 653, API 12R1, STI SP001, and, in Europe and the United Kingdom, EEMUA 159.

Regulatory requirements for emission sources (such as floating-roof designs, floating-roof seals, and tank vents) should be considered when establishing the inspection plans for tanks, as some environmental regulations require shorter intervals than those stipulated by API 653. In some cases, more frequent inspections or additional inspections of some emission sources are required.

5.1.3.4 Mechanical Integrity and Reliability

Inspections are an important part of avoiding failures, maintaining safety, and optimizing availability. Therefore, it is prudent to take a proactive approach toward storage tank inspection and maintenance to ensure continued integrity and reliability of the assets.

5.1.3.5 Tank Calibration

Tanks are calibrated for inventory and record reference; this is done upon construction and at future intervals to coincide with API 653 out-of-service inspections. There may be need for more frequent calibration records to meet Custody Transfer Requirements and US Customs Regulations. There are requirements and options to consider for external AST calibration. See API *MPMS* Ch. 2 for AST calibration requirements and options. With use of 3D imagery, this provides additional information for the AST inspector and integrity specialist (allowing information for future modification and tracking of changes over time).

5.2 Deterioration of Tanks

5.2.1 General

Corrosion is the prime cause for the deterioration of steel storage tanks and accessories. Locating and measuring the extent of corrosion is a major reason for storage tank inspection. If left unchecked, tank deterioration can progressively lead to failure, which may have adverse effects such as endangering personnel or the public, environmental and property damage, and business interruptions or damage to reputation.

5.2.2 External Corrosion

5.2.2.1 Atmospheric Corrosion

Atmospheric corrosion can occur on all metallic tank components exposed to the atmosphere. The type of tank, construction details, and environmental conditions can all affect the location, extent, and severity of external corrosion. For example, a sulfurous, acidic, or marine atmosphere can damage protective coatings and increase the rate of corrosion. External surfaces of the tank and auxiliary equipment will corrode more rapidly if they are not protected with coatings where surfaces are in contact with moisture or the ground. Extended contact with water is likely to cause localized corrosion. Such susceptible areas should be protected with coatings designed to withstand long-term immersion, or the owner-operator should consider alternative mitigation strategies. Inspections should target areas where tank construction details cause water or sediment to accumulate. For further information on atmospheric corrosion, refer to API 571.

5.2.2.2 Tank Bottoms

External corrosion of tank bottoms can be significant. Refer to API 650—Annex B “Recommendations for Design and Construction of Foundations for Aboveground Oil Storage Tanks” and Annex I “Undertank Leak Detection and Subgrade Protection” containing some optional details for tank bottom leak detection and corrosion protection. Refer to API 651 for optional cathodic protection design, and see API 655 for information on use of optional VCIs for soil-side corrosion protection (beneath AST bottoms). The foundation material used for forming a pad that is directly in contact with the steel bottom plates can contain materials that promote corrosion. For example, cinder is known to contain sulfur compounds that become very corrosive in the presence of moisture. The presence of clay, wood, gravel, or crushed stone as contaminants in a sand pad can cause pitting corrosion at each point of contact. Faulty pad preparation or poor drainage can allow water to remain in contact with the tank bottom. If a tank previously leaked corrosive fluid through its bottom, accumulation of the fluid underneath the tank can cause external corrosion of the bottom plates. For tanks that are supported above grade, an improperly sealed ringwall can allow moisture to accumulate between the tank and the support, thereby accelerating corrosion. A storage tank engineer should determine if the sealing design is appropriate and recommend the most appropriate design, which may include removal of the existing sealant. Any failing sealant that will remain should be repaired or removed. Asphalt-impregnated fiberboard is not a recommended sealant for tanks sitting on concrete ringwall foundations, as the fiberboard deteriorates and gaps are known to develop over time. For further information on sealing the bottom edge projection to the foundation, refer to API 654.The lower tank shell can be exposed to accelerated external corrosion near the grade line where soil movement has raised the grade level to cover the lower portion of the shell. Containment areas should be drained as soon as possible after water accumulates to minimize the possibility of bottom or lower shell corrosion. For further information on soil corrosion, refer to API 571.

5.2.2.3 Corrosion Under Insulation

External corrosion also occurs when insulation absorbs ground or surface water by wicking action or when damaged or improperly sealed openings around nozzles, roof-to-shell joint and attachments (including roof insulation at the perimeter where it meets the shell) allow water behind insulation. For further information on CUI, refer to API 571 and API 583. In cases where the wall of the tank is partially below grade, the inspector should pay special attention at the soil interface for accelerated corrosion.

5.2.2.4 Riveted Tanks

Riveted tanks are becoming increasingly rare in refinery and petrochemical plant operations; however, many riveted tanks are still in service and are included in inspection plans. API 650 does not provide guidance for the construction of riveted tanks.

Riveted tanks typically were constructed in accordance with API 12A, which has been withdrawn from publication. Other design and construction standards should also be referenced. Riveted tanks have many niches where concentration cell corrosion can occur (see 8.3.9.7). Leaks at the seams of riveted tanks can cause failure of external coatings, allowing external corrosion to develop.

5.2.3 Internal Corrosion/Deterioration

5.2.3.1 General

The occurrence of internal corrosion in a storage tank depends on the contents of the tank and its materials of construction. API 571 is a primary resource document for damage mechanisms and should be consulted when developing the inspection plan to ensure that proper inspection and examination techniques are applied. Annex A provides information on the more common NDE methods.

5.2.3.2 Product/Vapor/Sludge and Water Corrosion

Crude oil and petroleum product tanks are usually constructed of carbon steel. Internal corrosion of these tanks in the vapor space (i.e. above the liquid level) can be caused by hydrogen sulfide vapor, water vapor, oxygen, or any combination of these. In the areas in contact with the stored liquid, corrosion is commonly caused by acid salts, hydrogen sulfide or other sulfur compounds, dew point corrosion, or contaminated water that settles out and mixes with solids on the bottom of the tank, typically referred to as bottom sediment and water (BS&W). The salts and water in BS&W can serve as an electrolyte to facilitate electro-chemical corrosion on the top surface of the bottom. Sludge from sulfur containing crude and other high sulfur service applications can become anaerobic and mesophilic anaerobic microbes will convert sulfur to hydrogen sulfide, which when exposed to water will produce sulfuric acid (a strong electrolyte) that will facilitate loss of exposed steel. Microbial induced corrosion (MIC) does not directly corrode but induces the production of chemicals which facilitate electro-chemical corrosion. Use of dissimilar metals submerged within the electrolyte must be avoided. Issues of SCC can be of particular concern when the product is known to be corrosive to welds and other heat-affected zones. Ethanol, diethanolamine, and caustic products are just a few of the products that can contribute to this condition when in contact with bare metal. When storing biofuels and biofuel feedstocks, especially at elevated temperatures, the presence of free fatty acids and water at varying concentrations found not only in the product, but also in the vapor space, can lead to severe corrosion of the tank shell, roof structure and cone roof underside.

5.2.3.3 Linings

In some cases, it is necessary to use linings (see API 652) that are more resistant to the stored fluid than are the materials of construction. In some particularly corrosive services, it may be necessary to construct the tank with materials that are more compatible with the service environment, such as aluminum, stainless steels, or other alloys. These materials can experience deterioration from less common mechanisms, such as caustic or chloride SCC, acid erosion, flow erosion, electrolytic reactions, and cyclic fatigue, among others.

5.3 Leaks, Cracks, and Mechanical Deterioration

5.3.1 General

Storage tanks should be inspected for leaks (current or imminent) or defects to minimize or prevent loss, hazard to personnel, pollution of air, ground water, and waterways, and damage to other equipment.

5.3.2 Brittle Fracture

Brittle fracture and sudden loss of the contents of a tank can result in injuries to personnel and extensive damage to equipment in surrounding areas. Pollution of streams or waterways can result when such a tank failure occurs near a waterway or is connected to one by a sewer or other flow channel. Figure 17 illustrates the complete loss of a tank from brittle fracture. Proper design, fabrication, operation, and maintenance will minimize the probability of brittle fracture. A detailed discussion of brittle fracture can be found in API 571. API 653—Section 5.3 provides a procedure to assess the risk of tank failure due to brittle fracture and guidance for lowering the risk of brittle fracture. Brittle fracture is not a concern for nonwelded API 12B factory-coated bolted tanks.

5.3.3 Leaks

Leaks are primarily the result of corrosion but can occur at improperly welded joints, at riveted joints, at pipe thread or gasket connections or cover plates, or at crack-like flaws (including arc strikes on plates) in welds or in plate material. Three-plate laps in lap-welded tank bottoms are particularly prone to defects that can lead to leaks.

5.3.4 Cracks

Crack-like flaws can result from a number of causes including deficiencies in design, fabrication, and maintenance. The most likely points for crack-like flaws to occur are at the bottom-to-shell details, around nozzle connections, at manholes, around rivet holes or around rivet heads, at welded brackets or supports, drain dry connections, and at welded seams. The lower shell-to-sketch plate or shell-to-bottom weld is especially critical because in relatively large or relatively hot tanks there is a higher likelihood for this detail to develop a crack-like flaw due to high stresses. Potential for this occurrence can be minimized by the use of thicker, butt-welded annular bottom plates, which are required by API 650 for higher design stress tanks and for larger elevated temperature tanks (see API 650, Sections 5.5 and M.4.1, respectively). Photographs of typical crack-like flaws in tanks are shown in Figure 16, Figure 18, and Figure 19. Other cracking mechanisms are possible, including SCC. All cracking mechanisms are discussed further in API 571.

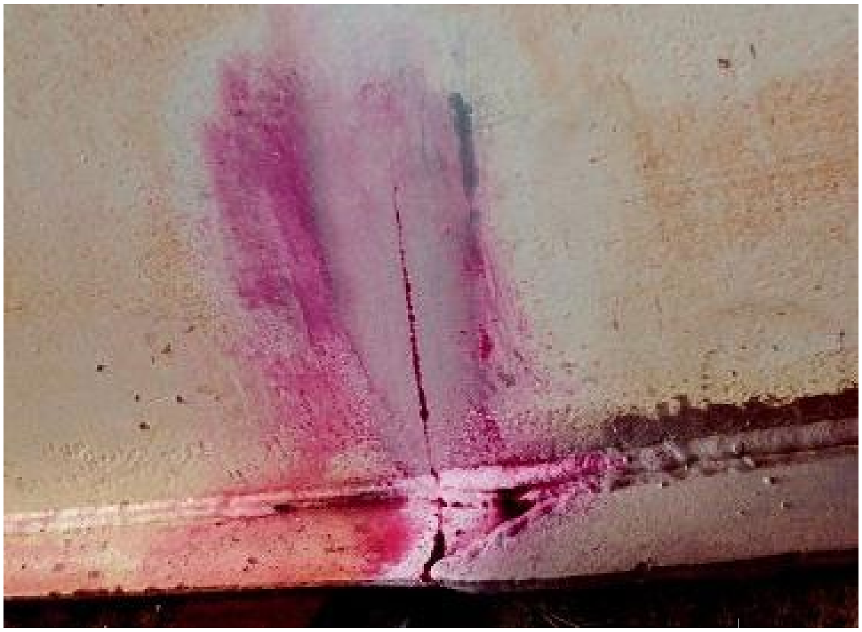


Figure 16—Cracks in Tank Shell Plate

Figure 17—Extensive Destruction from Instantaneous Failure

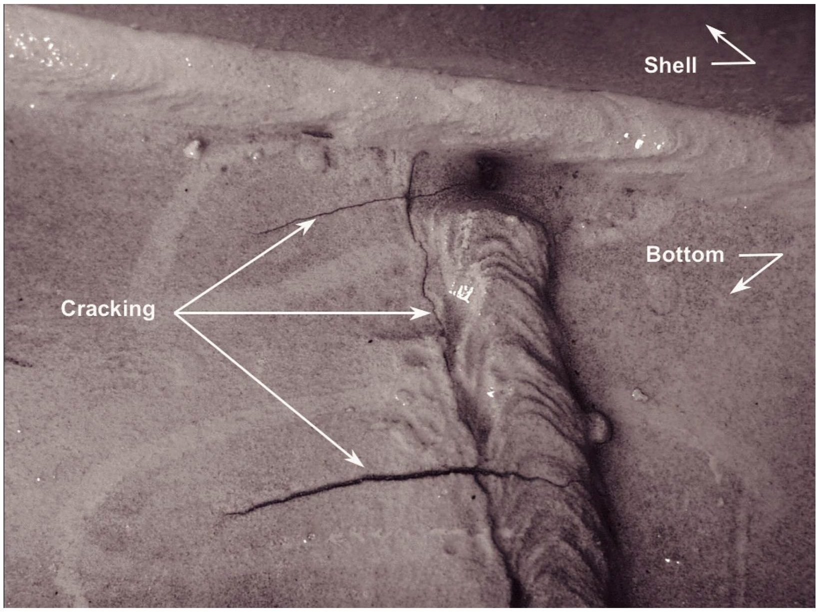


Figure 18—Cracks in Bottom Plate Welds Near the Shell-to-bottom Joint

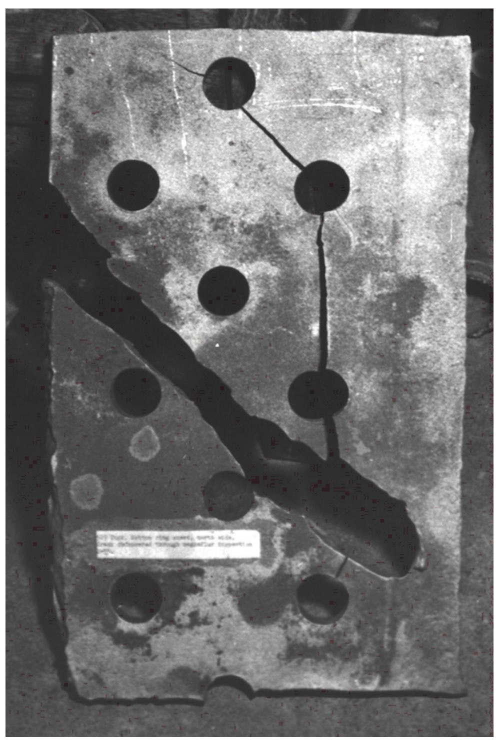


Figure 19—Cracks in Tank at Riveted Lap Joint to Tank Shell

5.3.5 Mechanical Deterioration

Many other types of mechanical deterioration can develop over the service life of a storage tank. If such deterioration is discovered early through inspection, continued deterioration can be minimized and potential failures and leaks can be prevented. Early detection of deterioration and conditions that cause deterioration permit cost-effective maintenance and repair to be done on a scheduled basis, minimizing the risk of failure. Examples of conditions that cause other types of mechanical deterioration can include severe service conditions, such as frequent fill/withdrawal cycling or elevated temperature (see API 650—Annex M) affecting the integrity of the shell-to-bottom weld, bulging, peaking, denting, overpressure, etc.

5.3.6 Settlement

Settlement of a tank due to soil movement under the tank or tank foundation can also cause mechanical deterioration. Uniform settlement of the entire tank would not necessarily cause structural damage or be considered a serious issue. Large or uneven amounts of settlement can cause nozzles with attached piping to become overstressed and possibly deformed or cracked or interfere with the normal operation of a floating roof. Significant amounts of uneven settlement should be cause for concern and for further investigation. Edge settlement in tanks with cone-down bottoms can trap BS&W, resulting in bottom and lower shell corrosion in this area. Soil and water can also be retained against the external shell when such settlement is present. Refer to API 653 for guidance on conducting settlement surveys.

5.4 Deterioration and Failure of Auxiliary Equipment

5.4.1 Tank Roof Equipment

Pressure/vacuum vents and flame arrestors can fail to operate for the following reasons:

a) the presence of fouling material or debris;

b) corrosion between moving parts and guides or seats;

c) deposit of foreign substances by birds or insects;

d) formation of ice;

e) accumulation of grit-blasting material;

f) the covering of the vent opening with plastic or the plugging of vent openings with paint during coating operations that is not subsequently removed;

g) tampering by unauthorized personnel;

h) improper setting of the pressure relief actuation set point or vacuum relief actuation set point.

Examination of tank venting devices should be included in a periodic inspection to ensure that their proper operation and protection are maintained. API 576 provides information regarding inspection of pressure-relieving devices and, specifically, weight-loaded pressure/vacuum relief devices.

5.4.2 Internal Equipment

Gauge float leakage can be caused by corrosion or cracking. Inoperative pulleys, bent or broken float tapes, or plugged guides can cause float-type gauging devices to become inoperative.

Equipment for draining water from floating roofs can be rendered inoperable by plugging or by mechanical damage caused by debris, ice, or rotation of the floating roof. Drain piping, mechanical joints, and hoses can develop leaks that will allow the tank contents either to leak from the roof drain system or allow water to flow into the tank. For single-deck floating roofs, leakage of the tank contents onto the floating roof can submerge or sink the roof. Inoperative drains with installed plugs (or with closed valves) can cause enough rain water to accumulate on the roof to sink a pontoon-type floating roof.

Heating systems inspections should take into consideration programs that address the specific types of equipment that are included (e.g. steam systems inspections should consider API 570 and API 574; bundle inspections should consider API 510 and API 572).

5.4.3 Shell Attachments

Deterioration of auxiliary equipment—such as ladders, stairways, platforms, wind girders, and shell stiffeners—can occur from corrosion, wind, and other external forces. Mechanical equipment, such as mixers, swing line pontoons, piping and swing joints, diffusers, jet nozzles and other flow direction details, baffles, rakes, and agitators, can suffer from deterioration due to corrosion, wear from flow erosion, and mechanical defects.

5.4.4 Miscellaneous

API 653—Annex C includes inspection checklists for many types of deterioration of storage tank auxiliary equipment and other appurtenances. The tank inspector should be thoroughly familiar with these checklists.

6 Inspection Plans

6.1 General

6.1.1 Developing Inspection Plans

An inspection plan is often developed and implemented for tanks within the scope of API 653 through the collaborative work of the inspector, engineer, corrosion specialist, and operations personnel. An inspection plan should contain the inspection tasks, scope of inspection, and schedule required to monitor damage mechanisms and ensure the mechanical integrity of the tank. Knowledge of the capabilities and limitations of NDE techniques allows the proper choice of examination technique(s) to identify particular damage mechanism in specific locations. The plan should typically:

a) define the type(s) of inspection needed (e.g. external, internal, thickness measurements, NDE, associated piping, etc.);

b) identify the regulatory intervals for seal or other component inspection needs, any applicable jurisdictional requirement, and the date for each inspection type;

c) describe the inspection and NDE techniques, extent, and locations;

d) describe any surface cleaning requirements needed for inspection and examinations;

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

f) describe any required repairs.

6.1.2 Incorporating Operations Information in Inspection Plans

Inspection plans should consider information such as operating temperature ranges, process fluid corrosive contaminant levels, material of construction, tank design and configuration, service changes since the last inspection, and inspection/maintenance history. Ongoing communication with operating personnel when process changes or upsets occur that could affect damage mechanisms and rates are critical to keeping an inspection plan updated. Other common issues in an inspection plan include the following:

— describing the types of damage mechanisms anticipated or experienced in the tank;

— defining the location of the damage;

— defining any special access requirements.

6.1.3 Inspection Records/Software

Inspection plans for tanks can be maintained in spreadsheets, hard copy files, and proprietary inspection software databases. Proprietary software, typically used by inspection groups, can assist in inspection data analysis and recordkeeping.

6.2 Inspection Planning and Reports

6.2.1 General

Prior to conducting internal or external inspection, the inspector should thoroughly review any available inspection records to become familiar with previous problems and recommendations noted.

6.2.2 Tank-specific Plans

Specific plans should address the following details for the tank to be inspected:

a) locations for inspection;

b) access requirements (scaffolding or other supports);

c) access limitations (road condition or width, infringements, etc.);

d) insulation removal;

e) considerations for roof inspection and access;

f) vents and vacuum breakers;

g) foundation issues;

h) seals and floating-roof components;

i) non-pressure-containing components required for tank operation;

j) cathodic protection;

k) linings and coatings;

l) removal of water or debris.

After the inspection plan has been implemented, each inspection report should address a number of factors, including the following:

a) corrosion rate calculations;

b) next inspection interval recommendations;

c) API 653 requirements;

d) inspection results, providing a description of the types of damage mechanisms in the tank and their exact locations.

6.2.3 Inspection Methodologies

API 653 provides criteria for condition-based inspection and scheduling of tanks utilizing internal and external visual inspection results and data from various NDE techniques (also refer to 7.2). API 653 also recognizes the use of alternative inspection methodologies. For example, robotic inspection is one possible approach to perform an assessment of the tank bottom and other internal components without personnel entry. Unmanned aerial vehicles or drones can be utilized for better access to rafters, thereby eliminating the need for man lifts or scaffold installation.

The use of external CMLs can make internal areas of the tank more accessible by external evaluation and provide repeatability of thickness readings on the tank shell and fixed roof. Cutouts in a tank's insulation at the CML points allow for visual examination of the exterior of the tank and allow for thickness measurements of the tank shell to be taken.

Replacement of all insulation and weather jacketing removed for the purpose of CUI inspection is critical and shall be performed in the shortest possible time frame following removal. Material of the same type, thickness, and layering shall be installed. Care shall be taken to ensure proper watershed of all-weather jacket materials.

6.2.4 Leak Detection

There are several different leak detection technologies or approaches, such as the following:

a) volumetric/mass leak detection methods;

b) acoustic emissions leak detection methods;

c) soil-vapor monitoring leak detection methods;

d) product dyes or treatments for detecting the existence of leaks;

e) inventory control leak detection methods;

f) monitoring the interstitial space in a double bottom tank.

These technologies should be inspected or tested periodically, as appropriate for the particular system and the risk involved.

6.2.5 Appurtenances

API 2610 provides additional guidance regarding the inspection of tank appurtenances, accessories, and the surrounding area.

6.3 Risk-based Inspection Plans

6.3.1 General

Inspection plans based upon an assessment of the risk associated with a tank failure (by determining the likelihood of failure and the consequence of failure) are referred to as risk-based inspection (RBI). RBI can be used to determine inspection intervals and the type and extent of future inspection/examinations. API 580 provides minimum requirements that must be considered to carry out a systematic evaluation of both the likelihood of failure and consequence of failure for establishing RBI plans. API 653 outlines the requirements and limitations for performing an RBI assessment for a storage tank. In addition, regulatory requirements in the applicable jurisdiction should be considered to determine acceptability of using RBI for inspection planning and scheduling.

NOTE At the time of publication of this edition of API 575, PHMSA does not allow the use of RBI for regulated breakout tanks.

6.3.2 Probability of Failure Assessment

Identifying and evaluating potential damage mechanisms, current tank condition, and the effectiveness of the past inspections are important steps in assessing the likelihood of a tank failure. The likelihood assessment should consider all forms of degradation that could reasonably be expected to affect tanks in any particular service. Examples of those degradation mechanisms include internal or external metal loss from an identified form of corrosion (localized or general), all forms of cracking, including SCC (from the inside or outside surfaces of a tank), and any other forms of metallurgical, corrosion, or mechanical degradation, such as fatigue, embrittlement, creep, etc. See API 571 for details of common degradation mechanisms.

6.3.3 Consequence of Failure Assessment

Identifying and evaluating the product or process fluid(s) in the tank and the potential for injuries, loss of containment, environmental impacts, and unit loss of production are important aspects in assessing the consequences associated with a failure of tanks.

6.3.4 Documentation

Any RBI assessment should be thoroughly documented in accordance with API 580, defining all the factors contributing to both the probability and consequence of a failure.

6.3.5 Inspection Plan

After an RBI assessment is conducted, the results can be used to establish the inspection plan and better define the following:

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

b) the extent of NDE (e.g. percentage or location of tank surface to examine);

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

d) the prevention and mitigation steps to reduce the probability and consequence of a failure (e.g. repairs, operational procedures, cathodic protection, coatings, etc.).

7 Interval/Frequency and Extent of Inspection

7.1 Interval of Inspection

7.1.1 General

API 653 provides requirements for inspection frequency of tanks built to API 650 and its predecessor, API 12C. API 12R1 provides guidance for inspection frequency for tanks built to API 12B, API 12D, API 12F, and API 12P (oil and gas production, treating, and processing services). STI SP001 can provide requirements for inspection frequency of shop-built tanks.

API 653 sets forth the requirements for the use of an authorized inspector for specific API 653 defined inspections. API 653 allows other than authorized inspectors to perform monthly and other inspections as needed.

7.1.2 Inspection Timing

7.1.2.1 Inspection Intervals

Although inspections are normally scheduled on intervals ranging from monthly to 20 years or more, some circumstances warrant immediate action to mitigate the potential for imminent hazards. For example, holes in the liquid or vapor space of the tank may pose immediate hazards. These holes can release flammable vapors, leading to serious incidents. Even without a substantial vapor release, the vapor space inside the tank may potentially be ignited by nearby hot work, lightning, or other causes, leading to very serious incidents. Holes in tanks should be reviewed by the inspector or storage tank engineer and addressed immediately.

7.1.2.2 Climatic Events

After severe climatic events (e.g. high winds, high water, heavy rain, or lightning strikes), potentially affected components should be checked. These components include, but are not limited to, the following:

a) the external floating roofs for excessive water loads;

b) the foundation for deterioration;

c) the external floating-roof deck and seals to see if they have been damaged;

d) the shell for evidence of deformation due to excessive loading.

7.1.2.3 Seismic Events

After seismic events that were significant enough to have impacted the integrity of the components of the tank, floating roof, and associated tank piping, an external inspection should be performed.

7.1.2.4 Leaks

If leakage is detected during an in-service inspection, a storage tank engineer should investigate to determine whether the leakage is caused by internal or external corrosion or some other condition that can be corrected while the tank remains in service. If the leak cannot be corrected with the tank in service, the maximum product level shall be set below the leak or the tank shall be taken from service.

7.1.2.5 Opportunities for Inspections Coordinated with Operational Issues

When applicable, owner-operators should attempt to coordinate inspections while tanks are out of service for operational issues. This scheduling often requires knowledge of internal inspection intervals, operating schedules, and operating experience for the tank(s) involved. Internal inspection intervals should also be based on experience and risk as determined by someone knowledgeable with the tank(s) and its operation. In no case should the maximum interval of these inspections exceed those prescribed by API 653 or regulatory requirements.

NOTE To minimize cost and reduce the generation of waste, every effort should be made to consider completing all necessary maintenance when tanks are out of service for inspection.

7.2 Condition-based Inspection Scheduling

7.2.1 General

Inspections scheduled and performed based on the past, current, and expected future condition of a tank (and its components) are defined as condition-based inspections. To meaningfully evaluate the condition of a storage tank, one can evaluate the data from previous inspections and the limits of corrosion and other forms of deterioration that can safely be tolerated.

7.2.2 Remaining Life Evaluation

The remaining life of a tank component (e.g. bottom, shell, or nozzle neck) due to thinning corrosion can be established using three key elements—the current thickness, the predicted or measured corrosion rate, and the minimum acceptable thickness. The current thickness for an evaluation is based on the minimum remaining thickness after any repairs. The corrosion rate is determined by the metal loss over time based on inspection information. There can be different corrosion rates for the internal and external side (product-side and soil-side for bottoms) of the components. The minimum acceptable thickness is determined from the criteria established in API 653 for the various components. When the minimum acceptable thickness has been reached (further thinning can pose an integrity issue), action should be taken. Generally, the remaining life and next inspection interval are determined by calculating the length of time, at the established thinning corrosion rate, that is required to reduce the current thickness to the minimum acceptable thickness. There are many factors to consider in determining each of the three key elements used to determine the tank remaining life. API 653 provides detailed guidance for determining these three key elements for the various components. The storage tank engineer shall be capable of performing or authorizing evaluations and designs as required by API 653. Assessment of the tank inspection results and evaluation of the tank condition and need for repair is best performed by an authorized inspector in conjunction with an experienced storage tank engineer.

7.2.3 Corrosion Rate Evaluation

For uniform corrosion, a corrosion rate can be estimated by plotting the metal thickness from two or more inspections against the inspection dates. An extension of the line drawn through the plotted points will provide an estimation of the time at which the metal will reach minimum acceptable limit, assuming a uniform linear corrosion. In addition to natural variation, changes to corrosion factors such as operating conditions, temperatures, cathodic protection, and other factors should be investigated to determine if corrosion rates will likely continue at the measured rate or whether the factors will cause the rate to increase or decrease. This should be considered in estimating the time at which a minimum thickness will be reached. Most other forms of deterioration, such as mechanical damage from wind, cracking of the tank metal, and operating failure of accessories, do not take place at a steady rate; they are better predicted with statistical methods. Corrosion pitting can occur at a nonlinear rate but is considered to be linear in API 653 for repair decisions and determination of inspection intervals. If the allowable limit of deterioration is calculated, knowing how long the tank will take to reach that limit establishes the service interval and next inspection. If the limit appears to be less than the desired service interval, repairs or replacements should be undertaken prior to putting the tank back into service. If that limit exceeds the desired interval, repairs may be postponed until the next scheduled out-of-service inspection.

7.3 Inspection Scheduling Based on Minimum Acceptable Thickness

7.3.1 Design Conditions

7.3.1.1 General

The minimum acceptable thickness should be determined based on API 653. Additional factors that need to be considered in order to determine an appropriate future corrosion allowance or to apply an additional safety factor include, but are not limited to, amount of information available on the tank, the type of fluid service in the tank, the risk exposure given the contents and location of the tank, the stresses the tank is subject to, the reliability of current inspection data, the type of corrosion experienced, and the applicable regulatory requirements. The storage tank engineer should determine the minimum acceptable thicknesses for components that are not established in API 653.

7.3.1.2 Allowable Stress Values

API 653—Section 4.3 provides one means of performing minimum thickness calculations using allowable stress values and joint efficiencies as given therein to assess tanks that have been placed in service. The minimum acceptable thickness for new tanks not yet placed into service is calculated per API 650 to withstand the product load, plus any internal (or external) pressure in the tank, plus a design allowance. Methods for determining the thickness of components in new storage tanks are given in the standards or codes to which the tank was constructed. Most of these standards are listed in Section 2. In most cases, the new thickness includes some excess thickness. This excess thickness may be the result of any one or all of the following factors:

a) additional thickness added to the minimum acceptable thickness as a corrosion allowance;

b) additional thickness resulting from using the closest, but larger, nominal plate thickness, rather than the exact value calculated;

c) additional thickness from deliberately setting a higher minimum acceptable thickness of plates for construction purposes;

d) additional thickness on the upper portions of shell courses not required for product loading at that level;

e) additional thickness available due to a change in tank service or a reduced operating fill height.

NOTE The excess thickness described under Item b) above will normally be rather small; however, with low corrosion rates, it can provide additional useful service life.

7.3.1.3 Service Stresses

Newer tanks (tanks built to API 650, Seventh Edition or later) may have an original plate thickness based on the specific gravity of the product to be stored or based on hydrostatic test requirements, whichever results in a thicker plate. Tank bottoms resting on grade and the roofs of atmospheric storage tanks are subjected to practically no membrane stresses from product loads. Bottom areas, away from the shell or annular ring, need to be only thick enough to be leak tight and to be at or above the minimum acceptable thickness per API 653 at the next out-of-service inspection. The roof shall also be thick enough to support its own weight plus the design live load. Weldability and the potential for deformations often dictate steel roofs and bottoms that are considerably thicker than required to withstand service stresses.

The pressure exerted on the sides of storage tanks by the weight of the liquid contained is greatest at the bottom and uniformly decreases up the shell. Because of this uniform pressure decrease, the shell plates above the bottom course may be thicker than needed for just product loading, but this should be verified by calculation. Large tanks have a slightly different stress profile and may have stress in the second shell course higher than predicted by the one-foot method. For tanks over 200 ft in diameter, API 653 requires the shell thickness to be computed by the variable design point method. For tanks subject to external pressure loadings, the required shell thickness should be calculated per Annex V of API 650. The thickness required to withstand external pressure loadings does not decrease as you move up the tank shell/wall.

If corrosion rate of the shell is established during inspection, any thickness not required for product and other design loads may be used as future corrosion allowance in determining the next inspection interval or can be considered when evaluating the maximum safe fill height.

7.3.1.4 Product Considerations

Storage tank shell plate thickness is normally calculated to contain a fluid of a desired specific gravity (usually water for the hydrostatic test in the case of atmospheric storage). If the actual service conditions are different from those contemplated in the design—for example, a stored fluid with a lesser specific gravity, a lower vapor pressure, or both—the existing shell courses may have excess thickness. Conversely, if the shells/walls have corroded, it may be necessary to reduce the allowable safe fill height of the tank or change the product stored to one with a lower specific gravity. Certain stored products may have a specific gravity greater than 1.0, and the shell plate thickness would be designed accordingly.

NOTE If the specific gravity is greater than 1.0, then a hydrostatic test condition does not reflect the loading of the product.

7.3.2 Existing Tank Conditions

7.3.2.1 Minimum Acceptable Thickness of Plates

API 653 provides methodology for determining minimum acceptable thickness for tank plate in existing tanks. This methodology can be used for estimating a point at which a tank may require repair or replacement or for scheduling the next inspection. The result will be a thickness that will be the minimum acceptable for a particular location in the given tank. When that thickness is reached, repairs or replacement shall be required. It should be kept in mind that a pit, or a very small area corroded to the retirement thickness, does not weaken the plate appreciably from the standpoint of resisting product loading but may result in a leak and should be eliminated. Evaluation methods for such localized areas are described in API 653. Pitting of bottoms shall be one of the determining factors in establishing the next internal inspection interval.

When MIC is encountered, provisions should be made to factor any accelerated localized corrosion due to MIC, which may lead to leaks or holes in advance of a minimum acceptable thickness based on uniform linear corrosion rates.

7.3.2.2 Minimum Acceptable Thickness of Components/Parts

For many parts of atmospheric storage tanks, neither the minimum acceptable thickness nor the methods for calculating the thickness are given in the tank standards. Such parts include pontoons, swing lines, floating-roof drain systems, nozzles, valves, and secondary structural members. Roof supports, wind girders, platforms, and stairways are covered by requirements in API 650 for atmospheric storage tanks and in both API 620 and API 650 for low-pressure tanks. There is no requirement in API 653 that existing structural members are required to be restored to API 650 as built standard or current applicable standard.

7.3.2.3 Minimum Acceptable Thickness of Structural Members

For structural members and parts, such as roof supports and platforms, normal accepted industry practice for structural design (such as methods provided in the *Steel Construction Manual* issued by the American Institute of Steel Construction) can be used to calculate the allowable loads of members in the new condition.

7.3.2.4 Minimum Acceptable Thickness of External Piping, Valves, and Flanges

For external piping and valves beyond the first flange, the methods provided in API 570 and ASME standards can be used to determine minimum acceptable thickness, inspections, and potential repairs.

7.3.3 Scheduling Impacts from Climate Effects on Coating

In northern or periodically wet climates, climate impact may be a consideration that affects inspection and repair methods. It is best to assume the worst-case repair when estimating project time. Starting at the end of the weather window, work backward, allowing time for coating, repairs, inspection, cleaning, tank preparation, etc., in order to select a start date. Cold weather coatings may be required depending on the geographic location of the tanks and the time of the year that inspection are repairs are occurring. In the Arctic and sub-Arctic, cold weather coatings will be required.

7.4 Similar Service Methodology for Establishing Tank Corrosion Rates

7.4.1 General

The internal inspection interval (i.e. operating interval) for atmospheric storage tanks, as defined in API 653—Section 4.4.5.1, is governed by the corrosion rate of the tank bottom. Similar service is an approach to estimating corrosion rates using data from other historical tank inspection data. As required by API 653, the purpose of estimating rates is to determine how long a storage tank can be operated before reaching the minimum thickness required of the tank bottom due to corrosion.

Similar service assessment guidelines are found in API 653—Annex H; Annex H is an informative annex and it states that the information presented in Annex H is a method of similar service assessment and other similar service assessment methods are allowed.

Similar service is recognized within industry as a means of scheduling internal inspection intervals in API 510, API 570, and API 653, which use corrosion rates as the basis for establishing inspection intervals.

7.4.2 Factors to Consider for Estimating Tank Bottom Corrosion Rates Using Similar Service

Although measurement of bottom thicknesses during an internal inspection to calculate a corrosion rate is an important means of establishing the next internal inspection interval, positively establishing the remaining bottom thickness is based upon many factors such as the amount, quality, and extent of inspections. Often, multiple inspection methods are utilized to establish the minimum bottom thickness [i.e. magnetic flux leakage (MFL) with follow-up ultrasonic inspection] to ensure that the worst area(s) of soil-side corrosion have been detected. When an owner-operator chooses to apply similar service to estimate tank bottom product-side and soil-side corrosion rates, the owner-operator should consider the factors listed in Table B.1.

Similar service is an acceptable method for independently estimating corrosion rates and may be used in lieu of, or in addition to, actual measurement of corrosion rates. Similar service has been found to be useful for prioritizing tank inspection when no tank bottom inspection data are available for a tank that is in operation. Rather than taking a tank out of service to establish corrosion rates, careful consideration of relevant similar service experience can be used to determine appropriate inspection priorities. Similar service is also used to supplement an internal inspection by using the data measurements of the internal inspection as an independent check on the anticipated corrosion rates. If there is a high level of confidence in the results of similar service from extensive data collection and available historical information, the extent of the internal inspection can often be limited by reducing the number of coupons required or the percentage of the bottom scanned. Since tank bottom condition typically dictates internal inspection intervals, only tank bottom corrosion is emphasized in this discussion.

When similar service evaluation is conducted for tanks on the same site, it is important for the inspector/engineer to realize that there is always the possibility that soil-side corrosion rates can vary from tank to tank simply by differences in quality control of foundation material, i.e. potential for lumps of clay, pieces of wood, presence of organic material, etc.

Similar service assessments may not be allowed by regulation for tanks under jurisdiction. Owner-operators should be certain about the applicability of similar service assessments for their facilities.

7.4.3 Sources of Corrosion

7.4.3.1 General

To use similar service, it is necessary to discuss the two aspects of tank bottom corrosion—product-side and soil-side corrosion. The similar service should be examined independently for both the product-side and the soil-side corrosion since the mechanisms and corrosion rates for each are independent of one another. As with any risk assessment approach, the owner-operator should assess the inspection effectiveness of tank bottom thickness data used in the similar service assessment.

7.4.3.2 Soil-side Corrosion

Similar service evaluation of soil-side corrosion rates is typically only useful for tanks located on a given site. Any given site may exhibit unique soil-side corrosion characteristics, and extrapolating soil-side corrosion from one site to another may not be appropriate. When doing similar service assessment for soil-side corrosion at the same site, it is important to know if any soil was brought from off site to build up the site around foundation of the tank, as different soils can have different resistivities and contaminants contained in them. Soil-side corrosion data may vary from negligible to very aggressive pitting with rates approaching 20 mil per year. The best source of soil-side corrosion rates comes from the examination of previously inspected tank bottoms from the same site.

7.4.3.3 Product-side Corrosion

Product-side corrosion is caused by the stored liquid. While many petroleum liquids have little to no corrosion, the tanks often have a layer of water that separates from the petroleum liquid. If the water is allowed to stand at the tank bottom or cannot be completely drained, it may be corrosive and cause product-side pitting and corrosion. Even with tanks that drain dry and include a shingled layout of bottom plate, it is possible for a sufficient amount of water to trapped against the steel that can contribute to localized corrosion and MIC. For petroleum crude oil tanks, water bottoms are often very aggressive sources of corrosion since the water contains various salts that increase corrosivity and are often stored at temperatures above normal, which also increases corrosion rates. Again, previous tank inspections are one source of information about the nature of corrosion that occurs on the product-side of the tank bottom for that particular service but may be misleading if crude or product storage changes over time. Table B.2 is an example of applying similar service principles to the product-side of the tank bottom.

7.4.3.4 Summary

To summarize, the corrosion experience at a site or in areas of similar soil conditions can represent the soil-side corrosion rates and be applied to a whole class of tanks, provided the tank pad selection is consistent across the facility. Product-side corrosion rates can be estimated from similar service in stock or stored product conditions that do not have to come from the same site, provided the tanks consistently store the same product. If you are using data from a different site, it is imperative that the service is truly similar since different sites can have many different variables that could have significant impact on the accuracy of the result (e.g. water draw frequency, product corrosivity, product temperature, etc.). Together, the data may be used to establish overall bottom corrosion rates and set internal inspection intervals where permitted by law and/or regulation.

7.5 Fitness-For-Service Evaluation

Aboveground storage tanks can be evaluated to determine fitness for continued service. API 579-1/ASME FFS-1 provides FFS evaluation criteria for tanks based on what is known or can be determined about the tank from various inspections. Different levels of assessment are provided depending on the information available for evaluation and resources available. FFS deals primarily with the evaluation of defects and flaws, such as corrosion, pitting, crack-like flaws, laminations, and distortions, that can affect remaining service life.

8 Inspections

8.1 Inspection Procedure

Inspection shall follow work procedures and certification requirements of API 653. A typical summary of the manual internal inspection process is as follows.

a) Aboveground storage tank is cleaned to allow for inspection.

b) Bottom is visually inspected, scanned, and mapped, with recommendations made by the authorized inspector for required deficiency repairs and optional maintenance.

c) Owner establishes a repair scope of work considering required deficiency repairs and optional maintenance needs. The owner may utilize an experienced AST engineer to review repair modifications to be performed.

d) After the tank repairs are completed, internal lining may be applied (if specified by the owner).

8.2 Preparation for Inspections

8.2.1 Safety Precautions

Before entering or re-entering any tank, appropriate safety steps are necessary. These precautions are discussed in detail in API 2015. Generally, such actions include, but are not limited to, the following:

a) isolation from any source of hazardous liquids or gases;

b) removal of hazardous liquids and gases;

c) removal of gas-generating, pyrophoric, or toxic residues;

d) assurance of an atmosphere that is safe for entry; API 2015 discusses the requirements for safe tank entry; where applicable, OSHA and/or any locally applicable safety agency regulations for safe entry into confined spaces should be followed; utilizing OSHA *CFR* Part 1910.146 would be appropriate, if under their jurisdiction;

e) stabilization of floating roofs and inspection of fixed roofs for structural integrity prior to allowing entry.

8.2.2 Tank Cleaning

A tank should be clean and free from surface residues, scale, and sediment to be properly inspected. Tank cleaning methods will be dependent on the amount of scale, sediment, solid product, or other foreign material that is present on the surfaces to be inspected. For relatively clean product services, water-washing the internal surfaces may result in adequate cleanliness for inspection, but it may be necessary to abrasive blast or high-pressure water clean (5000–10,000 psi, or 34–70 MPa) or high-pressure waterblast (10,000–25,000 psi, or 70–172 MPa) internal surfaces and weld seams to achieve sufficient cleanliness for inspection.

There are additional safety requirements when using high-pressure water blasting as compared to using high-pressure water cleaning.

8.2.3 Overhead Member/Floating-roof Inspections

Another aspect of inspection that is critical to safe operations is the inspection of floating roofs. In flammable liquid service, the integrity of the floating roof is critical to reducing the potential for roof sinking or flammable vapors above the roof, which can result in rupture of the bottom, leaks, tank fires and/or explosions. Steel annular-pontoon or double-deck floating roofs should be inspected and properly maintained to prevent failure while tanks are in service. For internal steel floating roofs, the compartments should be checked, whenever there is an out-of-service inspection, for possible wet spots or leaks in the pontoons due to corrosion or cracks in the welds. For external steel floating roofs, the compartments should be inspected for wet spots or leaks whenever there is an internal and an external inspection. The compartments should be vapor and liquid tight so that vapors cannot cascade from one compartment to the other. The inspector should note if the compartments are not vapor or liquid tight for owner-operator consideration.

For aluminum floating roofs that use pontoons for buoyancy, the pontoons should be inspected for leaks of product or vapors. Roof panels should be inspected for mechanical integrity. For cable suspended roofs, the roofs should be inspected for mechanical integrity and potential product or vapor or leaks.

The inspector shall make a visual inspection of overhead structural members, plate surfaces, and all supports to ensure that there are no loose rafters, large patches of loose scale, weakened support columns or brackets, or any other object that might fall and cause personal injury.

Drones are used for overhead inspection of roof structures to minimize hazards to personnel working from heights where there is often no access or difficult access above the floating roof. If there are any suspicion of roof structure issues, robotic techniques should be employed in lieu of making a tank entry with personnel.

In addition to an overhead inspection, a visual inspection of the top of any internal floating roof shall be performed to ensure that there is not any liquid that may overload the roof, causing it to collapse. To the extent possible, this overhead inspection should be conducted using inspection tools or from the entry point or other suitable observation points before working in the tank.

8.2.4 Tank Inspection Tools

Internal inspections performed while the equipment is in operation using nondestructive techniques, such as robotic MFL, phased array ultrasonic, short-range guided wave, or acoustic emission examination, may reveal important information without requiring entry into the tank. With such data and information, FFS or RBI evaluations can be performed, which can aid in maximizing the period of operation without taking the tank out of service. In addition, repair requirements can be planned and estimated in advance of taking the tank out of service to utilize downtime more effectively. These efforts can therefore contribute to overall plant availability by minimizing required downtime of the tank.

The use of remotely deployed tools continues to develop and progress. These tools include pole-mounted systems, magnetic wheeled devices (i.e. robotic crawlers), and remote aerial vehicles (i.e. drones). Pole-mounted systems and magnetic wheeled devices are typically deployed with corrosion mapping and visual camera systems but may also include leak detection capabilities. Drones are most commonly deployed with visual camera systems and light detection and ranging systems. Drone-mounted light detection and ranging systems can rapidly detect bulges, deflection, and settlement of tanks. Drones may also be deployed with infrared sensing, remote leak detection, and thickness measurement systems. Remote tools can be deployed within confined spaces provided that the proper safety precautions have been satisfied. These precautions include confirmation of explosive environment use certification and protective cages around propellers in the case of drones.

Advantages of remotely deployed tools include the following:

a) reduction or elimination of the need for lifts, scaffolding, and rope access to perform inspection;

b) improved safety by reducing or eliminating the need for personnel entry into confined spaces;

c) scanning patterns of robotic crawlers and drones may be preprogrammed and automated thereby increasing precision and repeatability;

d) product inventory does not need to be drained from the tank in the case of submersible remote inspection systems;

e) drone-mounted systems can externally inspect multiple tanks and/or large areas in a very short amount of time;

f) high-quality pictures and videos provide accurate documentation of inspection findings.

All tools and equipment needed for tank inspection and personnel safety should be checked prior to inspection to verify that they are in good working condition.

Table 1 lists some of the recommended tools for tank inspection. Those items listed in Table 2 should be available in case they are needed. Other tools can be selected and used appropriately.

Table 1—Suggested Basic Tools for Tank Inspection

Pit gauge
Magnifying glass
Inside calipers
Hammer
Knife or scraper
Notebook
Camera
Outside calipers
Paint or crayon (chloride-free item for use on stainless steel)
Permanent magnet
Plumb bob and line
Portable lights
Square
Steel rule
Straightedge
Crescent wrench
Ultrasonic thickness (UT) measurement instruments
MFL scanner
Remote inspection tools (unmanned aerial systems, etc.)

Table 2—Useful Supplemental Tools

Carpenter's or plumber's level
Magnetic particle inspection equipment
"Megger" ground tester
Liquid penetrant inspection equipment
Radiographic inspection equipment
Surveyor's level/transit or laser scanner
Sample removal cutters
Mirror
Vacuum box tester with soap solution
Bottom thickness-scanning equipment
Tools/methods for bottom leakage detection
Sectional pole or remote control for UT measurement instruments
Low-voltage or high-voltage testing equipment for coatings
NOTE Refer to API 652 for caveats when holiday testing linings that have been in service.

8.2.5 Tank Maintenance Support and Utilities for Inspection

Other support equipment that may be required for inspection can include planking, cribbing timbers, scaffolding, special rigging, and ladders. Special tank scaffolding that is safely mounted on wheels may be useful for efficient inspection and repair purposes.

Inspectors should have the following equipment and services available:

a) ventilation;

b) water for cleaning;

c) water and pressure gauge for testing;

d) compressed air for pneumatic tools;

e) electric power for tools and lights.

8.2.6 Coordination with Other Functions

In preparation for inspection, it is important that all personnel working in the area and any who may enter the area be informed that personnel will be working in the tank. Confined space entry procedures shall be followed if any tank entry is planned. Safety personnel or owner operations personnel should be consulted to confirm site-specific tank entry procedures. Personnel working inside the tank should also be kept informed before any other work close to the tank or on the exterior of the tank. If it is not safe to have work performed during inspection activities, either the work or the inspection should be scheduled at a different time. If personnel are working on top of a roof and inspection activities are scheduled below the roof, there is risk of loose scale and rust falling from roof members. Unless it can be determined to be safe for employees to work both on top of and below the roof, both activities should not be permitted to occur concurrently.

The owner-operator permit system should be used to coordinate multiple activities on the same asset.

8.3 External Inspection of an In-service Tank

8.3.1 General

Where an API 653 external inspection is being performed in conjunction with an API 653 out-of-service inspection, much of the external inspection can be conducted while a tank is still in service (prior to shutting down) to minimize the length of time the tank will need to be out of service. See API 653—Annex C for a detailed checklist of suggested items to be inspected while the tank is in service.

8.3.2 Ladder and Stairway Inspection

Ladders and stairways should be examined carefully for corroded or broken parts. The condition of the ladder (vertical or rolling), stairway parts, and handrails should be checked by visual inspection and, if appropriate, by mechanical means to assist in the inspection, to determine whether these parts are safe for continued use. Stairways and other access details (vertical ladders) should be evaluated per OSHA regulations in 29 *CFR* Part 1910 or other applicable safety standards.

Owner-operators should consider changes in the walking-working surfaces requirements in determining whether to evaluate according to the as build standard or the current applicable standard in OSHA 20 *CFR* Subpart D.

Stairs may be required to have intermediate rail, hand rail, and guardrail installed.

Large tanks may have intermediate support stairways. When concrete pedestals are used for such supports, they should be checked for cracks, spalling, and other problems. A scraper can aid in determining the extent of any concrete deterioration. Bolts set in the concrete should be examined carefully for corrosion at the point of contact, where a rapid form of crevice corrosion can take place.

Ladder rungs and stair treads should be checked for wear and corrosion. In addition to loss of strength caused by metal loss, the tread can become slippery when the surface is worn smooth. Solid treads, even though having adequate structural integrity, by their nature, may be a slip hazard, and owner-operators should consider this when evaluating the inspection results. Bolts and rivets should be checked for looseness, breakage, and excessive corrosion. Welded joints should be checked for cracks, undercut, erosion, and other defects. Handrails should be shaken to give an indication of their soundness. Handrails are required to be able to support a load on the top member without failure. Particular attention should be given to tubular handrails, which may have corroded from the inside. Crevices where water can collect should be closely checked by picking at them with a scraper or knife and by tapping them with a hammer. Such crevices can exist at bracket connections, around bolts and nuts, and between stair treads and support angles. If the surfaces are coated, corrosion may exist under the coating film. Rust stains visible through the coating and a general lifting of coating are evidence of such corrosion.

8.3.3 Platform and Walkway Inspection

Platforms, elevated walkways, and external floating-roof wind girders set up to be used as walkways can be inspected in the same manner as ladders and stairways. These components should also be evaluated per OSHA regulations in 29 *CFR* Part 1910 or other applicable safety agency. Existing floating-roof wind girders are typically not designed to be walking-working surfaces, and this intended use of these surfaces should be evaluated against the regulatory requirements for walking-working surfaces both in terms of dimensions as well as strength. The thickness of walking surfaces used by personnel can be checked at the edges with calipers. Tapping with a hammer and observing and listening may identify areas that need further evaluation. Platform grating hold-down fasteners should be checked for tightness. Low spots where water can collect should be checked carefully because corrosion may be rapid in such areas. Drain holes can be drilled in the area to prevent future accumulation of water. Platform supports should also be measured to determine thickness and should be checked for buckling and other signs of failure.

Defects requiring repair should be marked with paint or crayon and recorded in field notes or by some other appropriate means including electronic media (digital photography, video, etc.).

In areas with high seismic activity, the platforms and connections between tanks should be reviewed for sufficient flexibility to accommodate anticipated tank movement, especially after any seismic event.

8.3.4 Foundation Inspection

The foundations of tanks may be made of natural earth pads; sand or other fill pads; crushed stone pads or stone-filled grade bands; or steel and concrete piers, concrete foundation, or ringwalls.

Pads should be visually checked for erosion and uneven settlement. The condition of foundations and tank supports should be evaluated in accordance with requirements of API 653.

Tank level can be measured by using a surveyor’s level or other appropriate device to check the amount of settlement. Measured settlement should be evaluated in accordance with API 653—Annex B guidelines. Records of settlement should be maintained and referenced to permanent facility elevation datum. Concrete pads, base rings, and piers/footings should be checked for spalling, cracks, and general deterioration as shown in Figure 20. Scraping and use of a hammer on suspected areas can uncover such deterioration. If drip rings are installed, alternative methods of inspection may be required.

Wooden supports for small tanks, stairways, or other accessories can be checked for rot by tapping with a hammer, picking with a scraper, or probing with a knife or ice pick.

Steel columns or piers can be hammered and measured with calipers to check for corrosion. Caliper readings can be checked against the original thickness or against the thickness of uncorroded sections to determine any metal loss. Piers or columns should be examined to see if they are plumb. This operation may be done visually. Plumb lines and levels or laser measurements can be used if more accuracy is desired.

8.3.5 Anchor Bolt Inspection

The condition of anchor bolts can usually be determined by visual inspection. The area should be cleaned by scraping, picking, wire brushing, etc., to determine the extent of the corrosion. A tap with a hammer to the side of the nut may reveal severe corrosion of the anchor bolt below the base plate (see Figure 21 and Figure 22). Severe damage may not be detected by such a test. Visual inspection can be aided by removing the nuts one at a time, or supplemented by UT examination. Anchor bolt nuts should be checked for a snug fit to the anchor chair top plate (i.e. there should be no distance between the location of the nut on the bolt and the anchor chair top plate).

Figure 20—Failure of Concrete Ringwall

Figure 21—Anchor Bolt with Suspected Corrosion

Figure 22—Corrosion of Anchor Bolts

8.3.6 Grounding Connection Inspection

Some tanks are provided with grounding connections. The grounding connections should be intact. They should be visually examined for corrosion at the point where they enter the earth or attach to a grounding rod and at the tank ground clip. If there is any doubt about the condition of the grounding connection, its resistance can be checked. The total resistance from tank to earth should not exceed approximately 25 ohms. API 2003 provides information concerning the grounding of tanks to prevent ignition from static electricity, lightning strikes, or stray electrical currents.

Aboveground storage tanks of a certain size are considered inherently grounded. See NFPA 77.

8.3.7 Protective Coating Inspection

The condition of the protective coating on a tank should be adequately established during inspection. Rust spots, blisters, peeling, and cracking of the coating due to lack of adhesion are all types of common coating failure. Rust spots and blisters are easily found by visual inspection. Coating bond failure is not easily seen unless a blister has formed or has broken. Care should be taken not to significantly damage protective coatings during inspection. The coating inspection should identify areas of coating failure and the degree of active corrosion and existing corrosion damage.

Coating bond failure commonly occurs below seam leaks. Other points at which the coating may fail are in crevices or depressions and at tank seams that are welded, riveted, or bolted. The coating on the tank roof is especially susceptible to accelerated failure. The coating on floating roofs should be inspected carefully, especially in areas where water or product is retained.

8.3.8 Inspection for Corrosion Under Insulation and the Condition of the Insulation

If a tank is insulated, the condition of the insulation and weather jacket (if present) should be evaluated. Visual examination is normally performed. Detailed inspection should be conducted around nozzles, around the saddles of horizontal tanks, on roof insulation and the roof-shell insulation junction, at the corner weld where insulation rests on the bottom edge projection, and at caulked joints. Areas of insulation may need to be removed prior to such inspection, especially where the type of insulation is unknown. A few samples (cores) may also be removed—especially on the shaded side of the tank, on roofs, below protrusions, and at areas of obvious water intrusion—to better determine the condition of the insulation and the metal under the insulation. Insulation support clips, angles, bands, and wires should be spot-checked for tightness and signs of corrosion and breakage. If access is available internally, many of these areas (nozzle necks, external stiffeners, welded attachments) can be checked by UT examination from the inside. Significant corrosion can occur beneath insulation, at points near gaps in the weather protection, and in areas of the lower shell where the insulation may be in contact with surface water as shown in Figure 23 and Figure 24. Thermography and neutron back-scatter techniques to detect hot spots (or cold spots as the case may be) may also be useful in evaluating the condition of an insulation system in service.

Tanks that are susceptible to CUI should have a detailed inspection plan developed with identified locations for insulation removal at susceptible locations in order to expose enough of the underlying metal for adequate inspection. Alternatively, spots for the application of appropriate NDE should be identified (e.g. pulsed eddy current examination). CUI is most aggressive in temperature ranges between 170 °F (77 °C) and 230 °F (110 °C), in accordance with API 583, but can occur in temperature ranges between 10 °F (−12 °C) and 350 °F (175 °C).

Inspectors should exercise great care when inspecting insulated tank roofs. Thin roof plates may not be strong enough to support the inspector, and insulation could be damaged, allowing water to enter. Means of properly distributing personnel loading should be used when accessing such roofs of unknown condition for inspection purposes.

Replacement of all insulation and weather jacketing removed for the purpose of CUI inspection is critical and shall be performed in the shortest possible time frame following removal. Material of the same type, thickness, and layering shall be installed. Care shall be taken to ensure proper watershed of all-weather jacket materials.

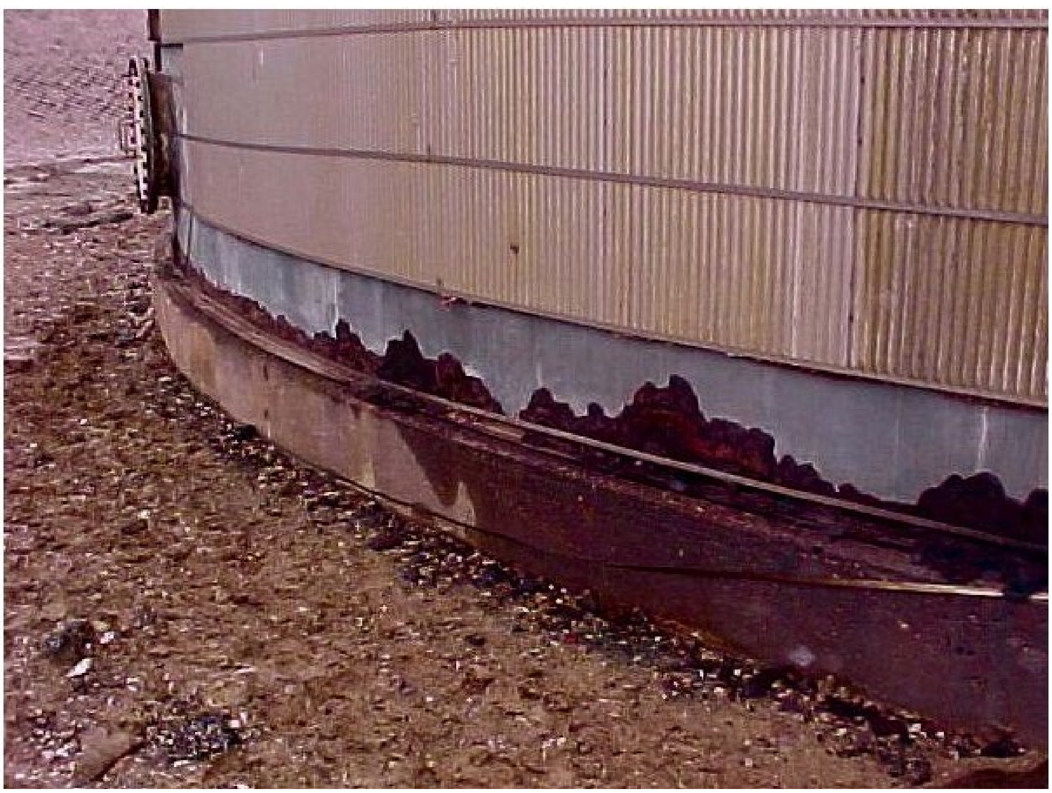


Figure 23—Corrosion Under Insulation

Figure 24—Close-up of Corrosion Under Insulation

8.3.9 Tank Shell Inspection

8.3.9.1 General

Inspection for coating failure to locate corrosion on the external surfaces of the tank can be of critical importance. Corrosion may occur on the shell near the bottom due to buildup of soil or other foreign matter and where product leakage occurs, especially if the tank contains corrosive materials.

If any foreign material or soil has collected around the bottom of the shell or if the tank has settled below grade, a close inspection should be made at and below the grade line. The shell should be uncovered completely in these areas and inspected for corrosion. Accelerated corrosion often occurs at the grade line, as shown in Figure 25. API 653 requires minimum dimensions of the bottom edge projection on an FFS evaluation. Tanks with product at elevated temperatures in cold climates may have water present near the shell and under the bottom because of ice or snow buildup around the tank.

When evidence of extensive external corrosion or other types of deterioration justifies further inspection, it may be necessary to utilize remote inspection tools or erect scaffolding for access to additional surfaces. Alternate rigging, portable ladders, cranes with man baskets, or man lifts can also be used.

Any evidence of corrosion should be investigated. Corrosion byproducts or rust scale can be removed by picking, scraping, wire brushing, or blasting (with grit, or water under high pressure) so that the depth and extent of the corrosion may be evaluated. Vigorous rapping with a hammer or with an air-driven chipping hammer with a blunt chisel can remove hard, thick rust scale. The potential hazards of using such methods should be evaluated beforehand. For example, hammer testing or removal of heavy scale should not be done with the tank containing any product.

Figure 25—Corrosion (External) at Grade

8.3.9.2 Thickness Measurements

8.3.9.2.1 General Corrosion

If corrosion is found, taking UT measurements at the most corroded areas is one method of assessment. If extensive corrosion is evident, it is more effective to take several measurements on each ring or to scan the surface with a thickness-scanning device supplemented by ultrasonic prove-up. Numerous thickness measurements may be necessary for assessing thickness in accordance with API 653—Section 4 guidelines. It should be emphasized that when UT is used for establishing corrosion rates, other evaluation methods may also be appropriate. These include similar service or establishment of corrosion rates from past internal inspections or substitution of higher rates from the bottom when applied to the shell.

8.3.9.2.2 Localized Corrosion

The depth of localized areas of corrosion can be measured by placing a straightedge long enough to span the corroded area on the longitudinal axis, then measuring from the straightedge to the lowest point of the corroded area. Isolated areas of corrosion can be measured by pit gauging.

Sun, shade, prevailing winds, and marine environments may affect the rate of external corrosion significantly. These factors need to be considered when determining the number and location of thickness measurements to be taken.

8.3.9.2.3 Upper Shell Course Measurements

UT measurements may be taken on the upper shell courses from ground level by the use of a sectional pole or a remote-controlled scanning tool. UT measurements taken from the outside should be compared with thickness measurements that may subsequently be taken from the inside. In obtaining shell thickness, special attention should be given to the upper 24 in. (600 mm) of uncoated shells of floating-roof tanks. These portions of the shell plates can corrode at a higher rate than the lower shell plates because of constant exposure to the atmosphere on both sides.

8.3.9.2.4 Establishing Shell Condition Monitoring Locations for Generalized Corrosion

CMLs should be established to monitor the general corrosion of the tank shell as part of the external shell inspection. Typically, UT measurements are taken at these locations to establish the shell thickness. CMLs should be set up on each shell course. Usually, several CMLs are established on a given plate and the lowest thickness reading is used to represent the shell course thickness. CMLs do not need to be marked on the tank, but it is important that the CMLs are identified sufficiently to ensure that thickness measurements are taken on the same shell course at each inspection so that variation in plate thicknesses is not misinterpreted as wall loss (or gain). It is typical to set up CMLs on the top, middle, and bottom of a given plate in easy-to-access locations, such as near ladders or stairs. The CMLs do not need to be in vertical line, and because this technique is used to monitor general corrosion, repeating the readings at the exact same location is not critical; however, localized corrosion may affect the results if the same location is not used.

8.3.9.2.5 Establishing Shell Condition Monitoring Locations for Localized Corrosion

CMLs may also be used to monitor specific locations of known localized corrosion. For instance, localized corrosion at a liquid/vapor interface identified during an internal inspection could be monitored externally by setting up CMLs that correspond to the internal locally thinned area. To monitor localized corrosion for the purpose of establishing very accurate corrosion rates, it is important that the exact CML is precisely identified so reading may be taken in a repeatable location for trending purposes. This can be accomplished by permanently marking the tank or by identifying the location on a drawing using accurate measurements from given tank features. Where it is more appropriate, a CML may be set up as a thickness scan of an identified area versus a thickness reading at a specific point.

8.3.9.2.6 Examiner Personnel Training

UT measurements should be taken only by trained personnel using a properly calibrated thickness measurement instrument and an appropriate thickness measurement procedure. Coatings can affect UT readings, and the examiner may need to compensate for the coating when recording the metal thickness measured. Modern ultrasonic multi-echo thickness scopes, when properly calibrated, allow direct metal thickness readings to be taken through thin-film coatings.

The examiner does not need to be an API 653 inspector or an employee of the owner-operator but should be trained and competent in the applicable procedures, which meet the requirements specified in ASME *BPVC*, Section V. In some cases, the examiner may be required to hold other certifications as necessary to satisfy owner-operator requirements. Examples of other certification that may be required include API QUTE—Qualification of Ultrasonic Testing Examiners (Detection), ASNT SNT-TC-1A or ASNT CP-189, or owner-operator/industry-approved equivalent. The examiner's employer should maintain certification records of the examiners employed, including dates and results of personnel qualifications, and should make them available to the API authorized inspector.

8.3.9.3 Stiffeners and Wind Girders

The outside stiffeners and wind girders of a tank can be inspected for integrity visually and by hammer testing or other testing methods. Tank shell corrosion is often found just above wind girders. Some wind girders can accumulate water, and they often have drainage holes that should be periodically checked to ensure that they are free draining. Thickness measurements should be made at points where corrosion is evident. Outside calipers and a steel rule are usually adequate to take these measurements, although UT measurements are more efficient and more accurate. Any pockets or crevices between the rings or girders and the shell should receive close attention. If the stiffening members are welded to the shell, the welds should be visually checked for cracks. If any evidence of cracking is found, the welds should be cleaned thoroughly by wire brushing or abrasive blasting for closer inspection. For maximum sensitivity, the areas can be checked by the magnetic particle or liquid penetrant examination method. If the magnetic particle method is used for detecting cracks while the tank is in service, current flow (prod techniques) should not be used because of the danger of sparks. For this type of examination, a permanent magnet or electromagnet (magnetic flow) technique should be used.

8.3.9.4 Stress Corrosion Cracking

8.3.9.4.1 Caustic Cracking

If caustic or amine solutions are stored in a tank and a corrosion specialist believes that the storage conditions may warrant an examination, the tank should be checked for evidence of damage from caustic (sometimes referred to as caustic embrittlement) or amine SCC. Refer to API 571 for more information on both types of cracking. The most probable place for this to occur is around connections for internal heating units or coils. This type of deterioration is manifested by cracks that start on the inside of the tank and progress through to the outside. If this condition exists, the caustic material seeping through the cracks will deposit readily visible salts (usually white). Figure 26 shows an example of caustic SCC. Thorough cleaning and checking with indicating solutions are necessary before welded repairs are conducted on steel that has been affected by caustic SCC. Cracking may occur during welding repairs in such areas.

Figure 26—Caustic Stress Corrosion Cracks

8.3.9.4.2 Ethanol Stress Corrosion Cracking

API 939E provides guidelines for identification, mitigation, and prevention of ethanol SCC. Internal inspections on tanks that have been exposed to ethanol, regardless of the duration, should be tested in accordance with API 571. This includes wet fluorescent magnetic particle testing (WFMT) of uncoated bottom lap welds, internal shell-to-bottom welds, all uncoated internal shell welds beneath the first horizontal shell weld (including vertical butt welds and nozzle welds), uncoated carbon steel floating-roof welds, and mechanical seal tension mechanisms. Coating shall be removed for WFMT.

NOTE WFMT requires surfaces to be cleaned to a near-white metal finish. The area extending 6 in. into the base metal on either side of the weld shall be prepared and WFMT inspected.

8.3.9.5 Hydrogen Blisters

When tanks are in service where hydrogen effects are expected, the shell and the bottom of the tank should be checked for hydrogen blisters. This form of deterioration is discussed further in API 571. Figure 27 and Figure 28 show the types of blisters that can occur either on the inside or outside surfaces. They are found most easily by visual examination and by feel. Visual examination should be aided by use of hand-held lighting of sufficient candlepower (at least 100 lumens) under low ambient lighting conditions, holding the flashlight against the shell so the light beam shines parallel to the shell surface. Many small blisters can be found by running fingers over the metal surface. The location of large blisters should be recorded so that while the tank is out of service, further inspection of the area can be made.

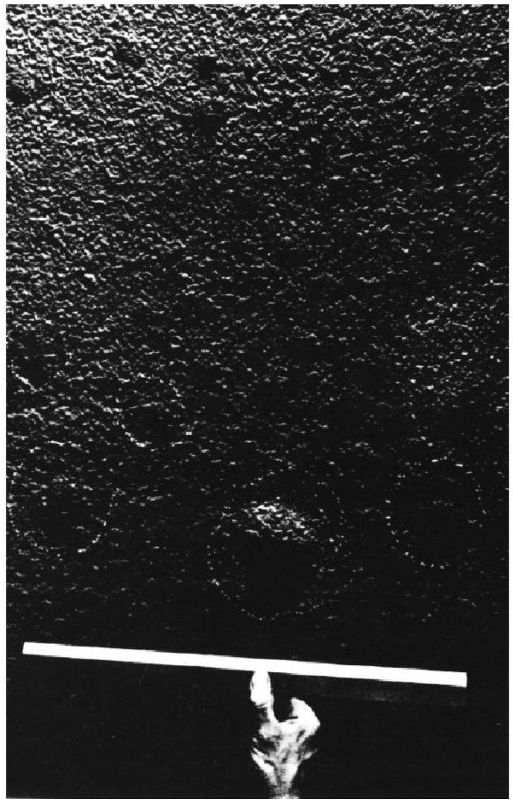


Figure 27—Small Hydrogen Blisters on Shell Interior

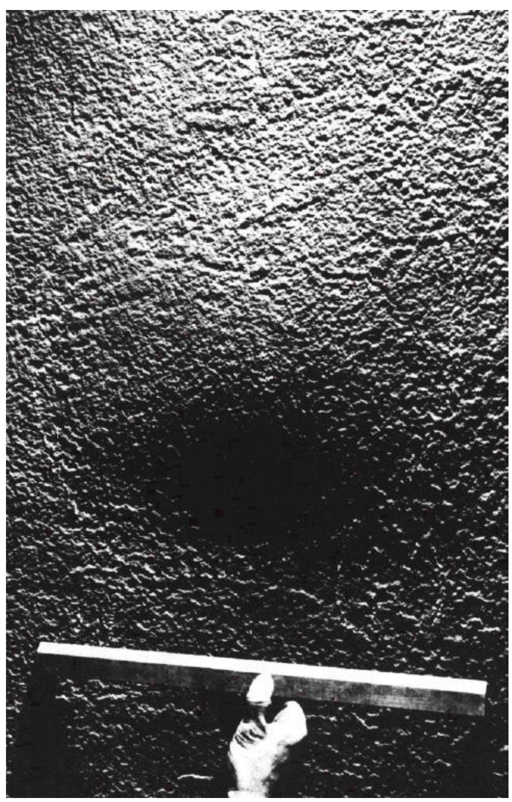


Figure 28—Large Hydrogen Blisters on Shell Interior

8.3.9.6 Leaks, Crack-like Flaws, and Distortion

8.3.9.6.1 General

In addition to an examination for corrosion, the shell of the tank should be examined for leaks, crack-like flaws, buckles, bulges, and banding or peaking of weld seams. Cracks in tanks are not as common as corrosion deterioration, but crack-like flaws can and do occur. Special attention should be focused on finding any crack-like flaws because the consequences of cracking failures can be far greater than those from corrosion. Cracks at the shell-to-bottom joint should receive prompt, focused attention as this joint is the most highly stressed joint in most tanks and when such a crack reaches a critical size, the consequences can be catastrophic.

8.3.9.6.2 Weep Holes

Normally, weep holes in reinforcing plates should not be plugged, so that pressure will not build up behind the reinforcing plate and tank leakage underneath the reinforcing plate will be evident. The weep hole may be filled with caulk, grease, or stainless steel 90-degree elbow to prevent corrosion, but should not be coated or filled with epoxy. Weep holes should be tested if one is found to be plugged.

8.3.9.6.3 Leaks

Leaks are often marked by a discoloration or wet spot in the area below the leaks. Leaks are sometimes found by testing the tank as discussed in 8.5 or by other methods discussed in 8.4.5. The nature of any leaks found should be carefully determined. If there are any indications that a leak is believed to be due to a crack, the tank should be removed from service as soon as possible, and a complete inspection should be made to determine the repairs required.

8.3.9.6.4 Crack-like Flaws

Although cracks in tanks are not common, crack-like flaws can occur. These can be found at the connection of nozzles to the tank, in welded seams, and in the metal ligament between rivets or bolts, between a rivet or bolt and the edge of the plate, at the connection of brackets or other attachments to the tank, and at the connection of the shell to the bottom of a welded tank. When an angle detail (i.e. mechanical joint) is found at the bottom joint of a welded tank, crack-like flaws can occur in the shell plate. Usually, close visual inspection is sufficient when checking for crack-like flaws, but for increased detection capability, liquid penetrant or magnetic particle examination should be used. If any signs of crack-like flaws do exist, the entire suspected area should be abrasive blasted or adequately cleaned by some other method for magnetic particle or liquid penetrant examination. API 653 allows the use of alternating current field measurement so coating may not need to be removed.

8.3.9.6.5 Deformations

Deformations will normally be readily apparent through visual inspection. Inspectors should consider that there could be slight deformations near a welded seam or elsewhere in the shell. Deformation can be measured by placing a straightedge lengthwise against the vertical shell or by placing a curved edge (cut to the radius of the shell) against the circumference. If deformation is present, it is important to determine the cause. Deformation can be caused by settlement of the tank, wind, earthquake, internal pressure in the tank due to defective vents or relief valves, an operating or induced vacuum in the tank, severe corrosion of the shell, movement of connected piping, improper welding repair methods, and other mechanical damage. Figure 29 shows an extreme case of tank deformation caused by inadequate vacuum venting. Settlement or frost heave of the soil beneath a tank bottom can cause deformation of the shell at the bottom edge. This can be checked with a straightedge level placed vertically at locations around the bottom.

When a welded tank has significant deformations, weld seams may be highly stressed and can crack. The joints most susceptible to cracking are those at connections, at the bottom-to-shell joint, at floating-roof deck lap seams, the shell-to-roof joint, and at vertical shell seams. Failure of a shell-to-roof frangible joint detail is shown in Figure 30. When cracking is suspected, magnetic particle examination is the preferred method to use. In using this method, the seams to be inspected should be abrasive blasted or wire-brushed clean. If the welded surface is rough or extends significantly above the surface of the joined plates, it may be necessary to grind the welds to obtain a reasonably smooth surface without sharp corners or discontinuities. Liquid penetrant and ultrasonic shear wave examination methods also can be used to find cracks. In addition, radiographic examination can be used, but it requires that the tank be emptied and prepared for personnel entry.

Figure 29—Tank Failure Caused by Inadequate/Obstructed Vacuum Venting

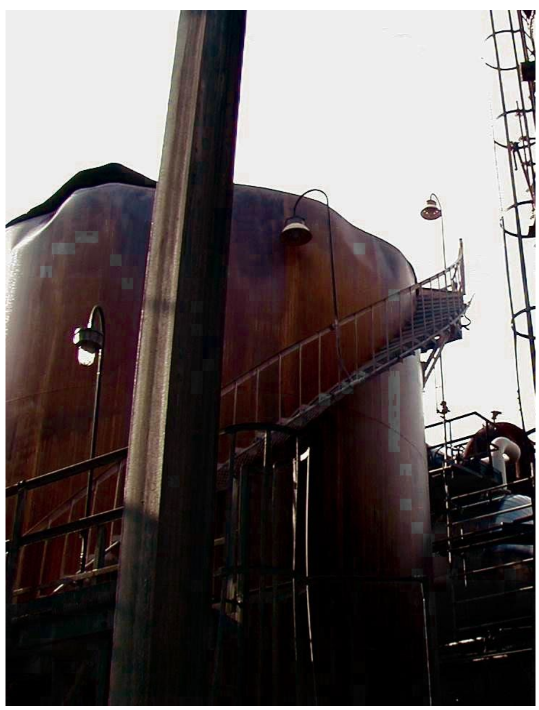


Figure 30—Roof Overpressure

8.3.9.7 Rivet Inspection

If the tank is of riveted or bolted construction, a visual inspection should be performed and a number of randomly selected rivets or bolts should be checked for tightness and product leakage. Movement of the rivet or bolt should not be detectable. It may be advisable to postpone any physical testing until the tank is out of service and the rivets or bolts can be checked on the inside of the tank. Alternatively, broken rivet bodies or bolts can be detected by ultrasonic examination while a tank is in service. The minimum thickness calculations mentioned in API 653—Section 4.3.4 for riveted tanks is applicable to the joint efficiency applied for the vertical joint, i.e. hoop stress.

Many riveted tank seams and rivets are coated with seam sealer or caulking. It is not recommended to remove sound and intact seam sealer unless there is a reason to suspect an integrity issue beneath the coating.

8.3.10 Tank Roof Inspection

8.3.10.1 Roof Access for Inspection

8.3.10.1.1 Fixed, Cone, or Dome Roofs

The roof or top head of a tank can be inspected for significant thinning by UT examination or even by MFL scanning (if the roof condition is thought to have enough strength to withstand the weight of the equipment). Hammer testing may dislodge scale from the internal plate surfaces into stored product and is not a recommended method of establishing roof plate integrity for personnel loading. Personnel should not be allowed inside the tank when these roof inspection activities are occurring. Suitable fall protection should be used when working on roofs. This includes an evaluation of the anchor point for the personal fall arrest system, if used, prior to perform the rest of the roof inspection. On a fixed roof, planks long enough to span at least two roof rafters should be laid and used as walkways or chain link fence may be used if thin spots are suspected, at least until the safety of the roof is determined. In general, the inspector should always walk on weld seams, if they are present and it is feasible to do so, because of the extra thickness available to support body weight.

8.3.10.1.2 Inspection of External Floating Roof

On a floating roof of unknown or questionable condition (e.g. insulated roof decks), the same precautions should be taken. In addition, because of the possible existence of harmful vapors, the floating roof should be as high as possible if volatile liquid is in the tank at the time of inspection. Inspection of internal floating roofs while in service should be avoided.

8.3.10.1.3 Confined Space Testing

If the tank is not full (i.e. floating roof is well below the maximum fill height), appropriate atmospheric testing should be performed before personnel are permitted on the external floating roof. If the entry onto the roof is considered to be a permit-required confined space entry, all confined space procedures shall be followed, including attendant, rescue team, and appropriate personal protective equipment, as required by the confined space policy and applicable regulations.

8.3.10.1.4 Access and Personnel Safety

The runway, rollers, and treads of any rolling ladders on the roof of a floating-roof tank are subject to wear and distortion. The ladder can be checked in the same manner as outside ladders or stairs. If the ladder has come off the runway because of roof rotation (which could result from seismic loading, high winds, or lack of suitable anti-rotation device), the roof—and especially the roof seals—should be examined visually for physical damage. The rollers on the ladder base should be freewheeling.

Platforms and guardrails on a roof should be checked carefully in the same manner as described earlier for stairways and ladders.

8.3.10.2 Floating-roof Grounding Systems

Grounding cables that connect the floating roof to the shell should be checked for breaks or damage. Broken grounding cables are common in freezing climates. Electrical shunts, if present, should be checked to ensure adequate contact between the floating roof and the shell.

8.3.10.3 Floating-roof Seals

Gaps between the shell and the seal(s) of a floating roof may be restricted by air quality regulations (local or federal). Minor emissions could be present at any time. Excessive emissions indicate improper seal installation, altered seal condition due to tank operations or long-term wear and tear, or a malfunctioning seal(s) due to external influences (earthquake, high winds, snow, and ice). Excessive emissions due to seal gaps can also result in rim space fires if a source of ignition (lightning strike) occurs. Visual inspection may be adequate to determine seal condition, and corrections may be possible while the tank is in service. If permanent repairs cannot be made, the defective areas and any temporary repairs should be noted in the records so that permanent repairs can be made when the tank is removed from service. Seal damage can occur if the maximum operating level is exceeded when portions of the seal are pushed up above the top angle or plate edge.

If an in-service seal inspection is required, in addition to the appropriate inspections performed on floating roofs and cone roofs, the vapor seals around columns and the ladder of internal floating roofs should be checked for leakage and condition. The ladder and columns should be checked for plumbness.

8.3.10.4 Floating-roof Drains

Drainage systems on floating roofs should be inspected frequently for leakage or blockage. If the drains are blocked, an accumulation of liquid can cause floating roofs to sink or to be severely damaged. This is especially true when the roof is sitting on its legs or has a poorly contoured deck that does not allow good drainage. Proper operation of check valves in drainage sumps should be verified on a regular schedule, especially for those in fouling or corrosive service. In some instances, owner-operators have chosen to disconnect existing roof drains when external floating roofs are covered with cone roofs or geodesic domes, converting them into internal floating roofs.

8.3.10.5 Depressions on Cone Roofs, External Floating Roofs, and Internal Floating Roofs

External corrosion on roof surfaces will usually be most severe at depressions where water can remain until it evaporates. In areas where bottom settlement problems continue to occur in service, columns may subside due to uneven bottom settlement, causing cone roofs to deform and retain water. Depending upon severity, repairs may be necessary. Covers on internal floating roofs are rarely watertight so rainwater may enter the tank and migrate to depressions on the horizontal surfaces of the internal floating roofs.

8.3.10.6 Vapor Leaks on External Roofs

When corrosive vapors in a tank leak through holes in the roof, pressure vents, floating-roof seals, or other locations, significant external corrosion may occur in these areas. Inspection for corrosion on the external surfaces of a roof may follow the same procedure as for the shell. UT measurements of badly corroded areas can be made if the thickness of the corroded roof plate is still within the range that the instrument can measure accurately. The inspector should be aware of the doubling effect that can occur when measuring thin material using a single element transducer; for example, a 180 mil (4.6 mm) roof thickness may show up on a digital thickness meter as 360 mil (9.1 mm). Multi-echo ultrasonic measurement equipment with an echo-to-echo mode can provide accurate thickness through thin-film coatings and should be used wherever possible.

8.3.11 Auxiliary Equipment Inspection

8.3.11.1 Pipe and Flanges

8.3.11.1.1 General

Tank pipe connections and bolting at each first outside flanged joint should be inspected for external corrosion. Visual inspection combined with scraping and picking can reveal the extent of this condition. See API 570 if piping beyond the first external tank flange is to be inspected. When external piping inspection of buried tank piping is specified, the soil around the pipe should be dug away for 6 in. to 12 in. (150 mm to 300 mm) to allow for inspection, as soil corrosion may be especially severe at such points. After the pipe is exposed, it should be thoroughly scraped and cleaned to permit visual and UT examination or other NDE.

8.3.11.1.2 Settlement or Frost Heave

Connected piping should be inspected for possible distortion if a tank has settled excessively, especially if the tank has been subjected to earthquake or high-water levels. In the latter case, water draw-off and cleanout nozzles connected to the bottom may have been subjected to high shearing or bending stresses. Special attention should be given to such nozzles. In colder climates, frost heave can raise piping supports and place excessive bending moments on piping nozzles and shell connections.

8.3.11.1.3 Distortion

Internal explosions, high winds, and fires can also cause distortion. If there is any evidence of distortion or cracks around nozzle connections, all seams and the shell in this area should be examined for cracks. The area should be abrasive blasted or wire-brush cleaned down to parent metal. Magnetic particle or liquid penetrant examination should be used for improved detection of crack-like flaws.

8.3.11.1.4 Seismic Activity

One of the most important aspects of piping integrity associated with the tank is sufficient flexibility to accommodate settlement or movement due to seismic activity.

8.3.11.2 Pressure/Vacuum Vents

Pressure/vacuum vents and breather valves should be inspected in accordance with 5.4 to see that they are not plugged, that the seat and seal are tight, and that all moving parts are free and not significantly worn or corroded. Thickness measurements should be taken where deterioration is located. Plugging of the discharge side screen and buildup of solids on the pallets are common problems.

8.3.11.3 Fire Protection

8.3.11.3.1 Dikes

Earthen and concrete dikes should be inspected to ensure that they are not eroded or damaged and are maintained at the required height and width. The dike containment should be checked for cracks, erosion, or any other signs of deterioration. Other dike containment materials, such as synthetic liners, should be inspected for integrity using inspection methods appropriate to the materials used.

8.3.11.3.2 Access

Stairways and walkways over dikes or firewalls should be inspected in the same manner as those on a storage tank. Drains for fire wall enclosures and dikes should be inspected to ensure that they are not plugged and that they are equipped with an operable drainage control valve.

8.3.11.3.3 Fire-fighting Equipment

Fire-fighting equipment attached to or installed on tanks, such as foam lines, chambers, connections, and any steam-smothering lines, should be visually inspected, and UT measurements should be obtained.

8.3.11.4 Flame Arrestors

Flame arrestors should be opened at appropriate intervals, and the screens or pallets should be visually inspected for cleanliness and corrosion. Bees and mud daubers occasionally plug arrestors. Solidification of vapors from the stored product may also restrict the flow area of the flame arrestor. If the venting capacity is seriously reduced under either pressure or vacuum conditions, the possibility of tank failure increases greatly. In the event of an explosion in a tank having a connected gas-collecting system, flame arrestors should be checked immediately for signs of damage.

8.3.11.5 Cathodic Protection Equipment

Cathodic protection systems should be maintained as indicated in API 651.

8.3.11.6 Other Auxiliary Equipment

Other auxiliary equipment should be inspected to ensure that it is in an operable and safe condition. API 653—Annex C contains detailed checklists for inspection of auxiliary equipment for tanks that are in service.

8.4 External Inspection of Out-of-service Tanks

8.4.1 Tank Bottom Inspection Performed Externally

8.4.1.1 General

A tank bottom can be inspected externally through tunneling or lifting a tank. With technology developments in the industry, tunneling under or completely lifting a tank just for soil-side bottom inspection should normally be avoided (see 8.5.5 for internal inspection). Lifting or tunneling methods may be used when justified by other considerations, such as a desire to coat the soil-side or the need to remove contaminated subgrade material or to install a release prevention barrier (RPB).

8.4.1.2 Tank Lifting Precautions

Tank lifting allows 100 % inspection of the bottom from the external surface after adequate cleaning but can be relatively costly for a large-diameter tank. Lifting does allow for blasting and coating (or recoating if the existing bottom is coated underneath), as well as tank pad releveling and access for repair. Inspection of a tank by lifting may necessitate a hydrostatic test that would be unnecessary with other methods (see API 653—Section 12). Tanks that have been physically moved, jacked, or lifted should be either hydrostatically retested, have the corner welds checked for cracking, or subjected to an engineering evaluation.

8.4.1.3 Tunneling Precautions

As it is difficult to refill a tunnel properly, tunneling should be applied only to locations near the edge of the tank. Clean sand is the best type of fill material.

8.4.2 External Pipe Connection Inspection

Inspection of pipe connections while a tank is out of service is essentially the same as when the tank is in service (see 8.3.11.1).

8.4.3 External Tank Roof Inspection

8.4.3.1 General

The external roof, either fixed or floating, should be inspected in accordance with 8.3.10.

8.4.3.2 Floating-roof Components

8.4.3.2.1 Roof Plate Corrosion

All roof plates should be checked for thickness, regardless of the external appearance. The inside surface of the roof plates may be susceptible to rapid corrosion because of the presence of corrosive vapors, water vapor, and oxygen. Figure 31 shows an example of roof corrosion that progressed completely through the metal. UT instruments should be used to check roof plate thickness. The same safety considerations as detailed in 8.3.10.1 regarding fixed roof inspection also apply to inspection of floating roofs.

On cone, umbrella, and similar fixed-roof tanks, on pan floating roofs, and on the lower deck of pontoon floating roofs, the thickness examination should be accomplished before the bottom of the tank has been thoroughly cleaned because considerable dust and rust may be dislodged from the inside of the roof.

8.4.3.2.2 Pontoons and Double Decks

The interiors of the pontoons or double decks on floating roofs should be inspected visually. Metal thickness measurements should also be taken. For stability, some floating roofs have weighted (with concrete or sand) or hollow pontoons (sitting on top of the roof deck not penetrating to the product) that should be checked to ensure that they are watertight. If these pontoons become saturated with water, corrosion can occur and the roof may not function as intended. A bright, portable light (of at least 100 lumens) will be needed for this work.

Figure 31—Example of Severe Corrosion of Tank Roof

8.4.3.3 Roof Rafters

The condition of the roof rafters in fixed-roof tanks can sometimes be checked through roof openings. Usually, the rafter thickness can be measured with calipers. Unless severe corrosion of the rafters is evident, these measurements should suffice. Coupons approximately 12 in. × 12 in. (300 mm × 300 mm) in size can also be removed from the roof to check for underside corrosion and rafter condition. All coupons should be round or have rounded corners; no square-cornered coupons should be cut.

Drones should be considered for inspection of roof structures and roof underside.

8.4.3.4 Importance of Finding Roof Leaks

While inspecting fixed or floating tank roofs for corrosion, a search for leaks should be made, although the best way to find leaks in the roof is with the low-pressure air test discussed later in this document. If the drain on a floating roof is blocked, liquid accumulations may eventually cause the floating roof to sink. In addition, any leakage into the pontoon of floating roofs or through the bottom deck of double-deck roofs can eventually cause the floating roof to sink. Leakage in the roof deck or in the pontoons can also cause the roof to become unbalanced and possibly damaged if it hangs up on the shell.

8.4.3.5 Seals

Before an inspection of floating-roof seals, the seal details should be reviewed so that the operation is well understood. The points at which problems can occur will thus become more evident. All seals should be inspected visually for corroded or broken parts and for worn or deteriorated vapor barriers. Any exposed mechanical parts—such as springs, hanger systems and other tensioning devices, and shoes—are susceptible to mechanical damage, wear, and atmospheric or vapor space corrosion.

8.4.3.6 Anti-rotation Devices

Most floating-roof tanks are equipped with guides or stabilizers to prevent rotation. These guides are subject to corrosion, wear, and distortion and should be inspected visually. If the guides are distorted or the roof is no longer in alignment with these guides, the roof may have rotated excessively. The shell should then be inspected for deformation or other defects as previously outlined in this section.

8.4.3.7 Roof Drains

Roof drains on floating-roof tanks can be designed in many ways. They can be simple open drain pipes or swing-joint and flexible-hose drains that keep water from contaminating the product. Roof drains shall function properly; if not, certain types of floating roofs can sink or not function properly. Figure 32 and Figure 33 show the severe damage that can occur. The damage in Figure 32 occurred while the roof was resting on its supports with excessive water load on top. The same type of failure can result from excessive snow, ice, or product loading. This kind of damage can be prevented by keeping the roof floating drain systems operating properly and by not landing the roof under such loading conditions.

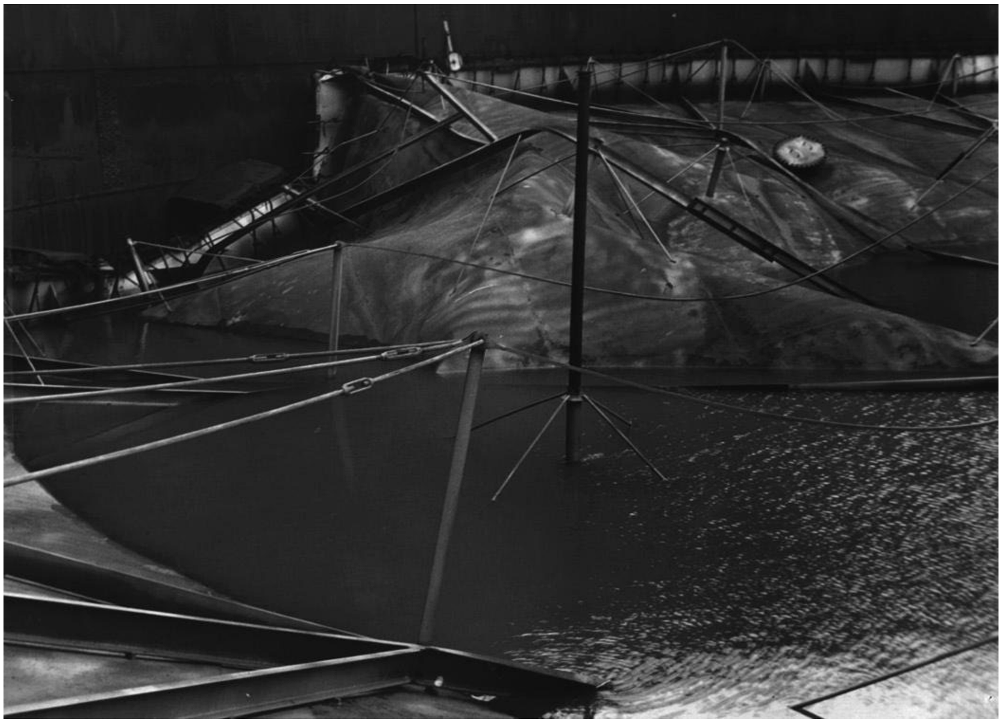


Figure 32—Collapse of Pan-type Roof from Excessive Weight of Water While the Roof Was Resting on Its Supports

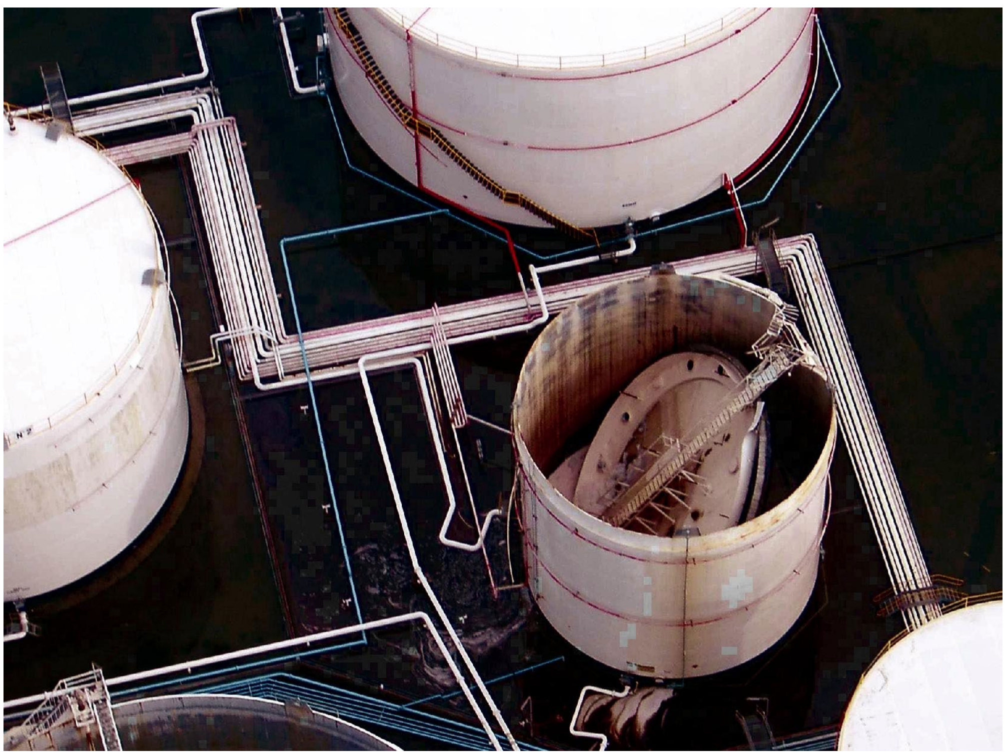


Figure 33—Pontoon Floating-roof Failure

8.4.4 Valve Inspection

Consider inspection and testing of all block valves on the outlet of tanks for leakage through the seat per API 598 and repair or replace, as needed. Valves can be refurbished if there is sufficient time during the out-of-service period, but this option could affect the return to service schedule for the tank. Water draw-off valves should be inspected to determine their condition.

Bonnet and flange bolts should be examined to ensure that they have not significantly corroded and that they are tight and have proper engagement length.

8.4.5 Auxiliary Equipment Inspection

8.4.5.1 Pressure-relieving Equipment

Pressure/vacuum vents and breather valves should be inspected in the manner described in 8.3.11.

8.4.5.2 Gauging Equipment

Liquid-level gauging equipment should be visually inspected. For float-type gauges, the float should be examined to find any corrosion or cracks and to ensure that it does not contain liquid. Cables and chains should be inspected for corrosion, kinks, and wear. Sheaves should be inspected to verify that they turn freely and are properly lubricated. Guides should be examined to ensure that they are free and not plugged. Any wooden parts should be checked for signs of rot. Refer to API 2350 for other testing methods of the overfill prevention system.

If a pressure gauge is used on a tank, it should be checked to ensure that the pipe connection to the gauge is not plugged, that the gauge is operative, and that it is reading accurately. For ordinary uses, the gauge can be checked for reasonable accuracy by connecting it to a suitable source of pressure and a gauge known to be accurate. For calibration purposes, a deadweight tester or a calibrated test gauge should be used.

Piping for the level switches can plug off, which will cause the switches to not work if needed. The entire system associated with an overfill prevention system can be tested while the tank is out of service by isolating the tank bridle and then filling to see if the overfill prevention system will trip.

8.5 Internal Inspection

8.5.1 General

To minimize downtime time, the inspection should be planned carefully. As previously stated, all necessary equipment (such as tools, lights, ladders, and scaffolding) and at the site in advance, and arrangements should be made to have all necessary mechanical assistance available. For large, tall tanks, a single-point suspended scaffold (also referred to as “tank buggy”) or rolling scaffold can be used as shown in Figure 34 and Figure 35. Any scaffolds shall be designed and installed according to OSHA or applicable safety agency, and users shall be properly trained on scaffold use and fall protection before assignment.

Warning—Scaffolds shall not be moved while personnel are on the scaffold.

Remotely controlled automated ultrasonic crawlers can also be used as shown in Figure 36. The need for adequate lighting for internal inspections cannot be overemphasized. The value of taking photographs or videotaping for inspection records should be considered.

Figure 34—Rolling Scaffold Used for Inspection and Repairs Inside of Tank

Figure 35—Single-point Suspended Scaffold Used for Inspection and Repairs on Exterior of Tank

Figure 36—Remotely Controlled Automated Crawler

8.5.2 Precautions

8.5.2.1 Cleaning

The tank shall be emptied of liquid, freed of gases, and washed or cleaned out as appropriate for the intended inspection. See 8.2 and API 2015 and API 653. Appropriate classification of the tank as a permit- or non-permit-required confined space for personnel entry and inspection work should be part of the permit process. Many tanks that are cleaned after removal from service are not completely gas free or product free unless particular attention is paid to areas where hydrocarbon buildup can be overlooked. Even in cases where the tanks are classified as a non-permit confined space, inadvertent trapped hydrocarbon or other hazardous chemicals may be encountered. Such areas include fixed-roof support columns, floating-roof legs, and guide poles (all fabricated from pipe or other closed sections without drainage holes), and bearing pads or striker pads on the bottom that may have leak paths (exhibited by product weeping). Diffusers and other internal piping extensions inside the tank open to the product can retain product in the piping inverts and should also be completely drained, cleaned, and made safe prior to inspection work. If during the inspection, the entrant discovers trapped product, the entrant shall immediately evacuate the confined space and contact the entry supervisor for further evaluation of the confined space prior to any confined space activity.

8.5.2.2 Internal Floating Roof

The design, construction, and physical condition of internal floating roofs, particularly the lightweight types (thin-skin aluminum and composite panel), should be taken into consideration prior to inspection. Planking may be required to walk on such roofs, even if they are not corroded. Many thin-skin aluminum panel designs are not intended to be walking surfaces. If there are no roof drains, adequate inspection should be made to ensure that water entering the tank above the roof does not accumulate resulting in an unsafe condition.

In cases where personnel are performing maintenance or inspection activities under a floating roof, cribbing should be installed near the manway and affected work area to ensure an emergency exit for personnel in the event of an issue with the roof support system. Owner-operators may have specific cribbing requirements based on tank size and floating roof design. See API 2015 for guidance on floating roof stabilization.

Inspectors should also be alert to accumulation of dry pyrophoric material (self-igniting when exposed to ambient conditions) during inspection. These accumulations may occur on the tank bottom, in the seal rim space areas, or on the top of rafters. Such accumulations that cannot be cleaned out prior to inspection should be kept moist to reduce the potential for ignition. See API 2015 for more information on controlling pyrophoric deposits.

8.5.3 Preliminary Visual Inspection

A preliminary, general visual inspection is the first step in internal inspection. Visual inspection is important for safety reasons since the condition of the roof or top head and any internal supports should be established first. The shell and bottom should follow—in that order—for the preliminary visual inspection. Any evident corrosion should be identified as to location and type (pitting or localized). The vapor space, the liquid-level line, and the bottom are areas where corrosion will most likely be found. Floating-roof tanks should be examined for loose or broken seal hangers and shoe bolt heads that can cause abrasive wear.

Following the preliminary, general visual inspection, it may be necessary to do further initial work before a detailed inspection can proceed. Any parts or any material hanging overhead that could fall, including large areas of corrosion (scale) products on the underside of the roof, should be removed or other accommodations installed to make it safe. In cases of severely corroded or damaged roof supports, it may be necessary to remove, repair, or replace the supports. Additional cleaning may be needed. If large areas are severely corroded, it may be best to have them water or abrasive blasted. From a personnel safety or equipment operability standpoint, it may be necessary to remove light coatings of oil or surface rust. After these operations are completed, the detailed inspection can proceed under safer circumstances.

8.5.4 Types and Location of Corrosion

Internal corrosion of storage tanks depends on the contents of the tank and on the material of construction. Severely corrosive conditions exist in unlined steel tanks storing corrosive chemicals or sour petroleum liquids. Corrosion should be uniform throughout the interior of such tanks, but nonuniform corrosion may also be present. In sour refinery fluid service, the vapor space above the stored liquid can be an area of significant corrosion. This is caused by the presence of corrosive vapors, such as hydrogen sulfide, mixed with moisture and air. The vapor-liquid interface is another region that may be subject to accelerated corrosion, especially when fluids heavier than water are stored. Although these fluids are not common in refinery storage, water will float on the stored fluid and accelerate corrosion. Figure 37 shows an example of vapor-liquid line corrosion. In this case, the stored fluid was 98 % sulfuric acid (not corrosive to carbon steel at this temperature and concentration). Moisture collecting in the tank produced a weak (corrosive) acid in the upper layer of liquid, resulting in the deep grooving shown. When the stored fluid contains acid salts or compounds, they may settle to the bottom of the tank, and if water is present, a weak (corrosive) acid will form. Pitting-type corrosion can occur in the top of tanks directly under holes or openings where water can enter, at breaks in mill scale, and adjacent to fallen scale particles on the bottom.

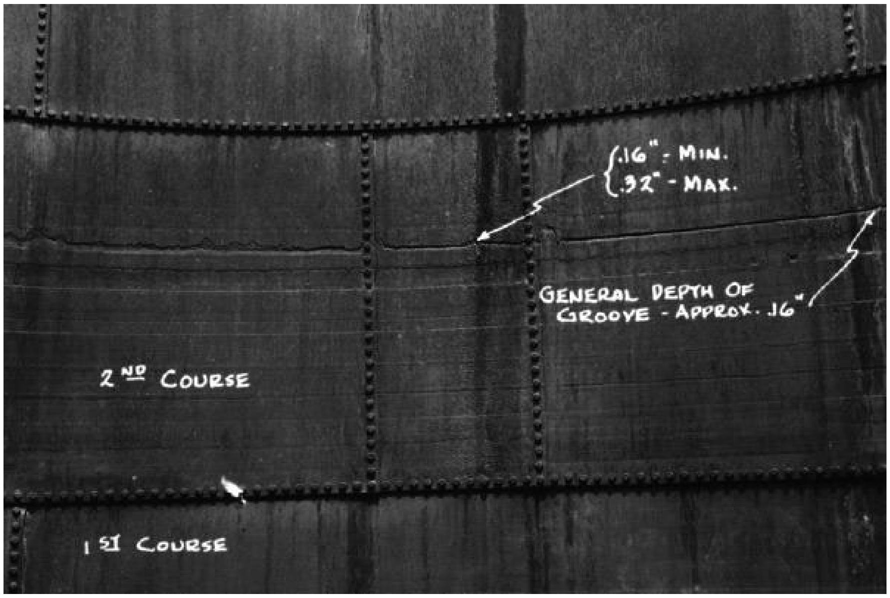


Figure 37—Example of Vapor-liquid Line Corrosion

Pipeline breakout tanks are often susceptible to accelerated corrosion behind floating-roof seals. Breakout tanks are typically used for the temporary storage of product prior to its injection into a pipeline system or to a final delivery location. Because storage is temporary, breakout tank roofs tend to be resting on legs the majority of the time. As the tank heats and cools, condensation, product residuals, and air trapped behind the roof seals will result in accelerated corrosion of the tank shell at the point where the roof seals normally rest. This type of corrosion is shown in Figure 38 and is typically identifiable as a band of corrosion extending around the tank circumferentially with a vertical height corresponding to the seal height. The severity of the band of corrosion may vary around the tank circumference depending on the location of the tank in relation to other tanks, the location of the sun, and other environmental conditions. The weld heat-affected zone has been found to corrode at an accelerated rate in relation to the surrounding shell plate material. Tanks built to API 650 prior to the Seventh Edition of the standard may have been constructed with incomplete penetration of the circumferential shell weld seams. The heat-affected zone corrosion may expose areas of incomplete fusion, resulting in areas where product can migrate within the interstice, presenting the possibility of flammable conditions.

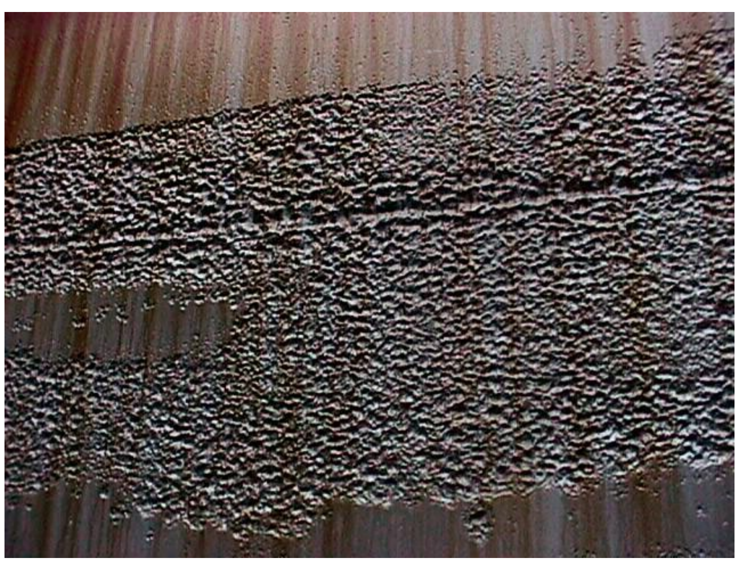


Figure 38—Corrosion Behind Floating-roof Seal

Among other types of deterioration that can occur on the shells of storage tanks are hydrogen blistering, caustic SCC, galvanic corrosion between dissimilar metals in close proximity, and mechanical cracking. Carbon steel that contains slag inclusions and laminations is more susceptible to hydrogen blistering. Caustic SCC may occur in tanks storing caustic products. Hot, strong caustic can also cause accelerated general corrosion. Areas of residual stresses from welding or areas highly stressed from product loading are most susceptible to caustic corrosion. Such corrosion thrives when the temperature rises above 150 °F (65 °C) and is most likely to occur around heating coil connections at the tank wall or at piping supports on the bottom.

If the insulation is not removed, or for low-temperature storage tank details that can make external inspection impractical, the shell can be inspected for external corrosion by ultrasonic area scans taken from the tank interior while out of service. This may help identify areas of external shell corrosion that could otherwise be undetected.

8.5.5 Tank Bottoms

8.5.5.1 Preparation

Good lighting is essential for a quality visual inspection. New LED technology has provided for greater lumens with less power and less heat being produced, resulting in safer and better lighting for tank interiors. A brush blast of the bottom can be performed for uncoated bottoms or for coated bottoms where the coating has deteriorated to enable a good visual inspection to be performed and to ensure the effectiveness of other NDE techniques.

Uncoated tank bottoms shall be sufficiently clean for an effective visual inspection of plate surface areas and welds. MFL scanning equipment, when properly calibrated and operated per approved procedures, is capable of detecting soil-side corrosion, even through thin-film coatings in good condition.

Some scanning equipment can also operate effectively through thick-film coatings and reinforced thick-film linings. General metal loss and significant pitting can be effectively located using scanning equipment. Availability of such equipment has greatly lessened the likelihood of not detecting such soil-side corrosion. It is recommended to examine some areas that have the lining removed in order to determine that the scan is accurate and there are reproducible results before completely relying on the technology for the bottom scan. It should be noted that sharp, small, isolated pits may not be detected with this equipment.

8.5.5.2 General

The tank bottom should be inspected over its entire area to assess whether significant soil-side corrosion has occurred and whether there are manufacturing or repair defects.

Coupon removal, the prevailing method of determining the presence of soil-side corrosion previously, is not a reliable enough method for locating areas of localized soil-side pitting when compared with the alternative methods available today. Representative sections or coupons [minimum size 12 in. (300 mm) each way] may be taken to confirm the results of MFL or ultrasonic examinations. The increasing accuracy of MFL, ultrasonic scanning, and other automated methods makes coupon removal less useful, especially considering the time and expense associated with replacing the coupons. Coupons are recommended for assessing the root cause of soil-side corrosion.

A range of NDE tools capable of rapidly scanning bottom plate for metal loss are now in use across the industry. MFL scanners are the most common, but hybrid MFL/eddy current, saturated low-frequency eddy current, and ultrasonic-based scanners may also be used. On unlined tanks, many operators specify a brush blast or a commercial blast cleaning to accommodate MFL bottom scanning and the visual inspection. When suspect areas are located, a more detailed quantitative UT or corrosion scan should be conducted. Depending on the bottom scanning equipment or procedures utilized, the amount of prove-up work may be minimized. Typically, straight beam manual UT examination is satisfactory for quantifying soil-side corrosion; UT flaw detectors showing the full waveform display should be used for this measurement. Alternatively, multi-transducer ultrasonic inspection scanning devices with digital or analog displays can be used to detect soil-side corrosion. Areas of signal loss in ultrasonic data need to be qualified further by additional inspection using methods such as manual A-scan, B-scan, or automated or shear wave ultrasonic testing. When ultrasonic scanners are used, the surface condition of tank bottom plates should be sufficiently clean to maintain adequate scanner accuracy during the inspection.

Experience demonstrates considerable variability in the effectiveness of tank bottom scanning inspection and UT prove-up. When conducted by qualified personnel, equipment, and procedures, scanning inspection can be highly effective. The owner-operator should consider the benefit in conducting a performance demonstration for personnel involved in tank bottom scanning and UT prove-up.

NOTE API 653—Annex C provides additional checklist entries for tank bottom inspection.

8.5.5.3 Statistical Sampling

Statistical methods are also available for assessing the probable minimum remaining metal thickness of the tank bottom, and the methods are based on a sampling of thickness scanning data. The number of measurements taken for a statistical sampling will depend on the size of the tank and the degree of soil-side corrosion found. Typically, 0.2 % to 10 % of the bottom should be scanned randomly. The collection of thickness data is required to assess the remaining bottom thickness. In addition, the outer circumference next to the shell should be included in the statistical sampling. When significant corrosion is detected, the entire bottom should be scanned to determine the minimum remaining metal thickness and the need for repairs. A note of caution is in order about statistical methods for assessing the condition of tank bottoms. Soil-side corrosion tends to be localized, especially if the tank pad is not of uniform consistency or has been contaminated with corrosive fluids or impurities. A statistically adequate sampling of the bottom can be helpful in establishing the existence of corrosion that could result in a tank leak prior to the next scheduled inspection. Statistical sampling methods are used for both physical entry and robotic inspection.

8.5.5.4 Pitting

Pits can sometimes be found by scratching suspected areas with a pointed scraper. When extensive and deep pitting is located and measurements in the pits are necessary, the areas may be abrasive blasted first, although it should be noted that this process can also create holes or open existing holes. Since abrasive blasting typically removes no more than 0.004 in. (4 mil) of sound steel, any holes created or holes opened up are areas that already lack sufficient integrity for FFS. The depth of pitting can be measured with a pit gauge or with a straightedge and steel rule (in large pits).

8.5.5.5 Seams in Riveted Tanks

Seams of riveted tanks can be checked by running a thin-bladed scraper or knife along the riveted seam. If the seam is open, the scraper will pass into the opening and disclose the separation. Rivets should be checked at random for tightness. Rivet heads should be checked visually for corrosion (see 8.3.9.7). This may involve considerable scraping and picking to clean corrosion products from the rivet head.

Because it is not feasible to inspect the soil-side of the rivet head, owner-operators should consider replacing riveted bottoms. At a minimum bottom rivets and seams should be caulked or sealed.

In the case of shell and roof rivets and rivet seams, sound and tightly adhering caulking or sealing should not be removed unless there is reasonable suspicion that there is an integrity issue. After repair, caulking and sealing should be restored.

NOTE These inspection techniques cannot guarantee a leak-free riveted joint.

8.5.5.6 Settlement and Depressions

The bottom should be checked visually for damage caused by settlement. Significant unevenness of the bottom indicates that this type of damage has occurred. If settlement is detected (internally or externally), the magnitude of the settlement should be measured. (API 653—Annex B provides guidelines for evaluation of tank bottom settlement.) Depressions in the bottom and in the areas around or under roof supports and pipe coil supports should be checked closely. Any water that gets into the tank may collect and remain at these points, thereby causing accelerated corrosion. These support details should have seal-welded bearing pads installed between the bottom and the support since they are areas that cannot be accessed to properly inspect them. 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. Low points, such as sumps or sloped bottoms, may retain water and make the inspection difficult, if not impossible. This condition should be corrected so that these areas, which are subject to higher-than-normal corrosion rates, can be carefully inspected.

8.5.5.7 Localized Corrosion

If localized corrosion or pitting is present (from either the product-side or the soil-side), single-point UT measurements alone are usually not an appropriate method of assessing the condition of the tank bottom. In such areas, techniques providing broader inspection coverage—such as ultrasonic scanning, MFL scanning, and coupon removal—may be necessary. Automated ultrasonic devices can be utilized to give a more accurate picture of the soil-side condition of areas of the tank bottom plates. An example of extensive bottom corrosion is shown in Figure 39.

Figure 39—Example of Extensive Corrosion of a Tank Bottom

8.5.6 Tank Shell

The area of highest stress in flat bottom tanks is commonly at the shell-to-bottom joint detail, and this area can be susceptible to corrosion as shown in Figure 40. This area should receive a close visual inspection for evidence of corrosion or other defects. If not coated (or if the coating is removed), this area can be further inspected by liquid penetrant or magnetic particle examination. It should be noted that a riveted shell-to-bottom joint using a structural angle detail is considered a mechanical joint, not a welded joint, and may not be suitable for certain types of examination. Riveted shell-to-bottom angles are typically coated with caulk or seam sealant.

Interior sources of shell seam (welded, riveted, or bolted) leakage noted during external inspection should be investigated during internal inspection.

The shell should be inspected visually for signs of corrosion. The product service conditions will determine the areas of corrosion. The vapor space and operating liquid level are the areas most subject to corrosion. If the contents are corrosive, the entire shell can be subject to corrosion. Figure 41 shows an example of a tank shell corroded completely through because of corrosion. When significant corrosion is found, additional UT measurements should be taken to supplement those measurements obtained from the outside.

When corroded areas of considerable size are located, sufficient thickness measurements should be recorded to determine the controlling thickness in accordance with API 653—Section 4.3.2.1.

While inspecting the bottom, the roof, and especially the shell of the tank for corrosion, the plate joints and nozzle connection joints should be inspected carefully for any evidence of cracking. A bright light and a magnifying glass will be very helpful in performing this work. If any evidence of cracking is found, a thorough investigation using magnetic particle, liquid penetrant, radiographic, alternating current field measurement, or ultrasonic shear wave examination should be undertaken. See API 653—Annex C for additional guidance on shell inspections.

Figure 40—Shell-to-bottom Weld Corrosion

Figure 41—External View of Erosion-corrosion Completely Penetrating a Tank Shell

8.5.7 Testing for Leaks

For tanks not provided with under-tank leak detection systems, a search for leaks through the bottom should be performed at the internal intervals prescribed by API 653, in addition to a search for leaks through the shell. If the tank is to be hydrostatically tested during the course of the inspection, the hydrostatic test may be one method for detecting shell leaks. If a hydrostatic test is not to be made, a penetrating test liquid (such as diesel) can be sprayed or brushed on one side of the shell plate in suspect areas and the other side can then be observed for leakage. Lower temperature will extend the time for oil penetration to become visible on the other side of the area being inspected. The liquid penetrant method used for finding cracks can also be used in much the same manner, with the penetrant applied to one side of the plate and the developer applied to the other side. For either method, approximately 24 hours may be required for leaks to become evident. Tank bottom leak detection methods are described in Section 9.

8.5.8 Linings

Special inspection methods may be needed when the inside surfaces of a tank are lined with a corrosion-resistant material, such as steel or alloy steel cladding, rubber or other synthetic fabric, organic or inorganic coatings, glass, or concrete (see API 652). The most important considerations to ensure that the lining is in good condition are that it is in proper position and does not have holes or cracks. With alloy steel or more rigid metal linings, such as nickel and Monel, inspections should be made for leaks or cracks in the lining joints. A careful visual examination is usually required. If there is evidence of cracking, the liquid penetrant examination method can be used. The magnetic particle examination method cannot be used on nonmagnetic lining material.

With rubber, synthetics, glass, and organic and inorganic linings, the general condition of the lining surface should be inspected for mechanical damage. Holes in the lining are suggested by bulging, blistering, or spalling. In addition to visual inspection, audible testing is a recommended method for certain thick linings. Lab testing of samples and adhesion testing may be considered; however, these are destructive test methods.

To avoid mechanical damage to the linings, considerable care should be taken when working inside tanks lined with rubber, synthetics, glass, or organic or inorganic coatings. Glass-lined tanks are especially susceptible to severe damage that cannot be easily repaired. Glass-lined vessels should never be hammered or subjected to any impact on the inside or the outside because the lining can crack. It is advisable to coat them a distinctive color or to stencil a warning against striking them prominently on the external shell. It is important to keep spillage off the outside of glass-lined tanks. Corrosion from spillage can result in hydrogen penetration and cause defects in the glass liners (glass-lined tanks commonly contain materials that are more corrosive than can be stored in unlined or internally coated tanks).

Concrete linings are difficult to inspect adequately, primarily because the surface is porous. Concrete-lined steel bottoms are impractical to inspect unless the concrete is removed. Mechanical damage, breakage, spalling, major cracking, bulging, and a complete separation of the lining are common and visible. Minor cracks and areas of porosity are more difficult to find. In some instances, they may be seen as rust spots on the surface of the concrete caused by steel corrosion products leaking through the lining. Corrosion behind the lining is possible where the concrete bond with the steel has failed.

8.5.9 Roof and Structural Members

Ordinarily, a visual inspection of the interior roof plates, framing system, and column supports is sufficient. Remote inspection tools (e.g. unmanned aerial systems, etc.) may eliminate the hazards of elevated work and should be considered before using scaffolding. When corrosion or distortion is evident or heavy underside roof corrosion is indicated, access should be provided so that measurements can be taken internally. If corrosion is noted on the roof and upper shell, then structural members may also be damaged, possibly with losses more than double the thinning of the roof or shell, since multiple sides of the structural members are exposed to the corrosive vapors. See API 653—Annex C for guidance that is more detailed. Figure 42 shows an example of internal corrosion of roof plates and rafters.

When local corrosion has been found on the inside of the shell, any roof support columns should be checked closely at the same level. Transfer calipers and steel rules or UT equipment should be used in measuring structural members. Measurements should be checked against the original thickness or the thickness of uncorroded sections. If corrosion or distortion of the members is evident, structural welds and bolting should be examined to determine the extent of the damage. Light hammer taps can be used to test the tightness of bolts and the soundness of structural members, but hammer tests are qualitative and cannot determine integrity without data.

The underside of all types of floating roofs should be inspected for corrosion and deterioration not seen during the external or in-service inspection described in 8.4.3. Vital parts of some roof seals, such as the hanger supports of a mechanical shoe seal, can only be inspected from the underside.

In addition to the appropriate inspections performed on floating roofs and cone roofs, the seals around columns and the ladder of internal floating roofs should be checked for leakage and condition. The ladder and columns should be checked for plumbness. The legs and leg sleeves should be checked for soundness and straightness. Aluminum floating-roof leg supports need to be adequately isolated from bare carbon steel as recommended in API 650—Annex H to avoid corrosion by direct contact of dissimilar metals.

Figure 42—Internal Corrosion on Rafters and Roof Plates

8.5.10 Internal Equipment

8.5.10.1 General

Any internal equipment, such as pipe coils, coil supports, swing lines, nozzles, and mixing devices, should be visually inspected. Coils and supports should be checked for corrosion, deformation, misalignment, and cracking. Except for cast iron parts, the coils and supports should be ultrasonically examined or hammer tested. Coils should be tested hydro-pneumatically for leaks. Wet steam coils should be inspected for condensation grooving in the bottom of the piping coil using radiography or ultrasonic testing. If cracks are suspected in the nozzles or nozzle welds, they should be checked by the magnetic particle or liquid penetrant examination method. Figure 43 shows a typical installation of heating units in a tank, and Figure 44 shows an example of heating coil corrosion.

Figure 43—Fin-tube Type of Heaters Commonly Used in Storage Tanks

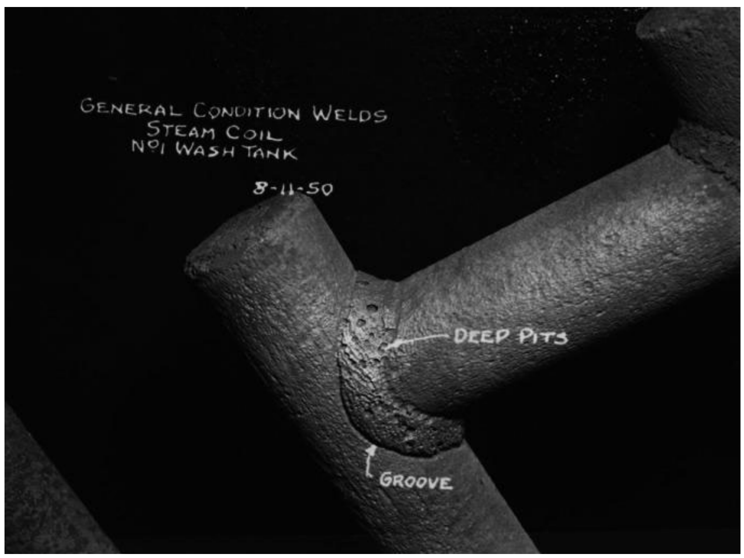


Figure 44—Example of Corrosion of Steam Heating Coil

8.5.10.2 Swing Lines

The swing lines of floating-roof tanks may be equipped with pontoons, rollers, and tracks. The pontoons should be hammer tested and checked for leaks. The thickness of the pontoon wall can be measured by ultrasonic testing. The tracks and alignment rollers should be inspected visually for corrosion, wear, and distortion. The roof deck in the area of these tracks should be checked for bulging, which can occur if the swing line pontoons create an extensive upward thrust. Swing line rollers in contact with the underside of internal floating roofs should also be inspected for damage or restricted movement. See API 653—Annex C for more information.

8.5.10.3 Water Draw-off Piping

Water draw-off details are subject to internal and external corrosion and crack-like flaws. They are especially subject to crack-like flaws if they are cast iron, and they should be visually inspected to the maximum extent possible. Cast iron items should be upgraded to more appropriate materials when feasible. Conversion to a water draw-off sump of the type and materials illustrated in API 650—Figure 5.21 may be desirable under certain conditions. Internal low suction details should be examined for both internal and external corrosion.

8.5.10.4 Tank Nozzles and Piping

The thickness of the tank nozzles and pipe walls should be measured with UT instruments (especially if the connecting pipelines carry corrosive products or if there is any other reason to expect internal metal loss). Visual examination of a piping connection is usually made at the flange connection closest to the tank (by dropping a valve or unbolting the connection). Caliper measurements of the pipe can be made if a joint is opened. The caliper measurements will require emptying the line and blinding it at some point beyond the opened joint, emptying the connecting piping between the point of isolation and the open joint, and making that connecting piping safe and gas free. Gasket surfaces of opened flanges should be checked for corrosion, and the flange faces should be checked for distortion by using a flange square. Nozzle thickness can be calculated by measuring the inside and outside diameters or it can be determined by UT measurement. As corrosion may be greater on one side of the nozzle, a visual or UT check for eccentricity of the nozzle interior surfaces should accompany these measurements and calculations.

8.5.10.5 Drain Lines

Some drains are built such that the only possible way to measure wall thickness is by using calipers or by ultrasonic examination methods. Any movable joints in the drain lines should be checked visually for wear and tightness. The drain lines, including the joints, can also be tested for tightness by pressure testing with water, if designed for internal pressure. It has been found that a two-stage hydro-pneumatic test procedure is desirable. Drainpipe and hose systems of primary drains shall be tested with water at a pressure of 350 kPa (50 lbf/in.^{2}) gauge. During the flotation test, the roof drain valves shall be kept open and observed for leakage of the tank contents into the drain lines. Testing should follow the manufacturer's recommendation.

8.6 Hydrostatic and Pneumatic Testing of Tanks

8.6.1 Testing

The word testing, as used in this section, applies only to the process of filling the tank with a liquid or gaseous fluid, at the appropriate level or pressure, to verify the tank for integrity and the foundation for adequate support or for shell or floating-roof leaks.

8.6.2 Hydrostatic Testing

8.6.2.1 General

When storage tanks are built, they are tested in accordance with the standard to which they were constructed. The same methods can be used to inspect for leaks and to check the integrity of the tank after repair work. When major repairs or alterations have been completed, such as the installation of a new tank bottom or the replacement of large sections of shell plate, the test requirements are specified in API 653. If the repairs have not restored the tank to an equivalent full-height operating condition, the water height for the test should be limited in accordance with the lower-strength conditions revealed during a re-evaluation of stored product height limitations.

8.6.2.2 Atmospheric Tanks

Atmospheric storage tanks designed to withstand only a small [0.5 psi (3.5 kPa) gauge is typical] pressure over the static pressure of the liquid in the tank are normally tested by filling with water. The lower portions of a tank are thus tested at a pressure that depends on the depth of water. All visible portions of the tank can be checked for leaks up to the water level. For certain high-strength and high-alloy steels, consideration should be given to the purity of the water for testing since contaminants, such as chlorides, can lead to the possibility of SCC, especially in austenitic stainless steels (see API 571). Consideration should also be given to the notch toughness of the shell material at the air and water temperatures existing at the time of the test. A discussion of notch toughness and brittle fracture can be found in API 571 and in API 653—Section 5. If water is not available and if the roof of the tank is reasonably air tight or can be made so, a carefully controlled air test using air pressure not exceeding 2 in. of water pressure (0.50 kPa) may be applied. This type of test is of very little use as a strength test and is used only in inspection for leaks. For this test, indicator solution is applied to the outside surface of any suspect areas of the tank, shell, and roof weld seams, so that the air escaping through any leak path will produce bubbles indicating the leak location. Roof seams can be effectively vacuum tested in the same manner. Very small leaks and some large leaks in welded seams may not be detectable using the vacuum box method.

8.6.2.3 Low-pressure Tanks

Low-pressure storage tanks can be tested in a similar manner as atmospheric storage tanks but at slightly higher pressure depending upon their design (see API 620).

8.6.2.4 Double-walled Tanks

The interstitial space of double-walled tanks for secondary containment integrity should not be tested while the inner tank is empty. The static head pressure of that water could cause buckling of the tank shell near the bottom similar to pulling a vacuum on the inside of the tank.

8.6.3 Pneumatic Testing

Carefully controlled pneumatic testing can be used when water or other suitable liquid is unavailable, when a tank would be unstable when filled with liquid, or when a trace of water cannot be tolerated in the stored product. If a tank is significantly corroded, pneumatic testing should be avoided. If it is necessary to use the method, an inert gas such as nitrogen should be used to test tanks that have previously held a flammable or combustible liquid products, and caution should be exercised to avoid excessive stresses that could lead to brittle failure. Inspection for leaks can easily be made by applying an indicator solution to the outside weld seams of the tank and looking for bubbles.

Caution—Pneumatic testing should not be applied to tanks that have been in service. During pneumatic testing, the tank should not be left unattended, and personnel should not stand in front of fittings. When used, the potential personnel and property risks of pneumatic testing should be considered by an engineer before conducting the test. A pneumatic test procedure should be developed by the engineer following the steps outlined in ASME PCC-2, Article 501.

8.7 Inspection Checklists

API 653—Annex C (informative) provides sample checklists of items for consideration when conducting external and internal inspections of aboveground storage tanks. These checklists, although relatively thorough, are not necessarily complete for all possible situations, especially for tanks other than those covered by API 653. Additionally, these checklists are not intended as minimum inspection requirements for all situations. They should be used judiciously by the inspector as guidance for issues and items to be checked during inspections, both internal and external.

9 Leak Testing and Integrity of the Bottom

9.1 General

9.1.1 Release Prevention Barriers

Tanks that have impermeable foundations (reinforced concrete), under-tank liners, or tanks constructed with double bottoms provide an inherent leak detection system that directs leaks to the perimeter of the tank where they can be visually detected in accordance with the leak detection provisions of API 650—Annex I.

These systems are collectively referred to as RPBs. RPBs are not typically retrofitted with additional leak detection devices, cables, or sensors because these would provide limited added value based upon industry experience. The owner-operator may elect to perform additional bottom integrity testing after repairs are made; the procedures that follow may assist in that assessment. While tankage that complies with a tank integrity program built upon API 653 generally has acceptable environmental performance, specific circumstances may warrant the use of additional measures to ensure that tanks are not leaking. When regulations or a risk assessment indicates the need for additional measures, then the owner-operator can apply advanced technology leak detection systems, such as those specified in 6.2.4.

9.1.2 Procedures and Practices

This section provides information on procedures and practices that may be used to assess the hydraulic integrity of the tank bottom. Except as specifically required in API 653, all procedures identified here are recognized to be optional when used for attaining an enhanced confidence in the hydraulic integrity for a repaired or newly constructed replacement tank bottom. For those owner-operators that already have procedures for determining the suitability of the tank bottom, this discussion may serve as a reference when policy warrants a change in their methods.

Figure 45 identifies test procedures and summarizes operational issues that the tank operator should consider when assessing a suitable inspection strategy regarding the hydraulic integrity of tank bottom construction.

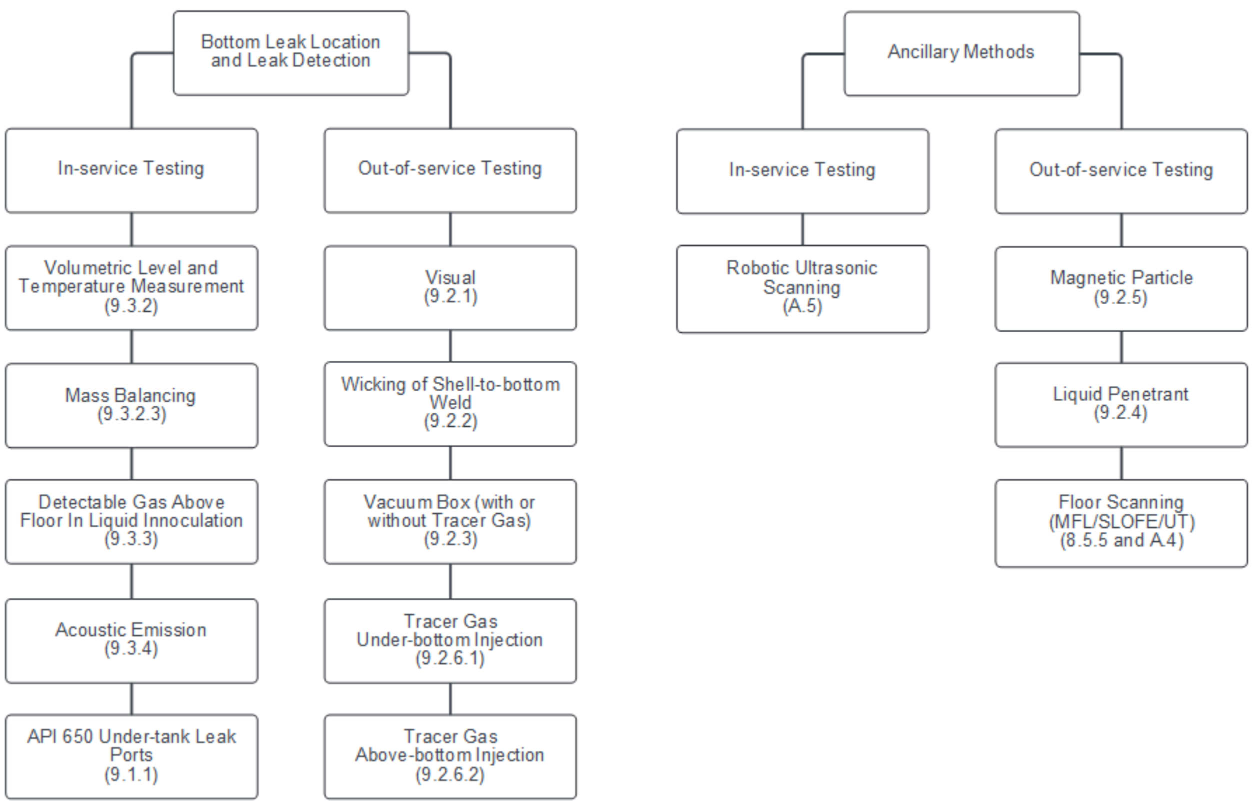


Figure 45—Hydraulic Integrity Test Procedures

9.1.3 Preferential Procedures

In cases where API 653 shows preference for specific procedures in specific applications, these cases are noted. It is beyond the scope of this document to assess the specific performance characteristics of one method compared to another or to cover the impact of multiple testing with multiple technologies. As with any NDE method, it is the responsibility of the owner-operator to make that assessment. It is anticipated that examiners have qualifications consistent with API 653. Additional factors to consider include vendors and technologies that have been qualified by third-party testing agencies or owner-operators. These methods may be required by various regulatory agencies or companies and provide other effective ways to evaluate the needed qualifications.

9.1.4 Considerations

When using information provided in this section, considerations for schedule, operational, economic, and environmental characterizations should be reviewed. An owner-operator should be familiar with conditions under which the procedures can be used.

9.2 Integrity Testing Methods Available During Out-of-service Periods

9.2.1 Evaluation by Visual Examination

Visual inspection may be direct type when the surface is readily accessible to place the eye within 24 in. (61 cm) of the surface at an angle of not less than 30 degrees. The minimum illumination is 15 foot-candles (25 lumens) for general viewing and 50 foot-candles (100 lumens) for viewing of small anomalies. Visual inspection may be remote by using mirrors, cameras, or other suitable instruments. The test would detect surface defects, such as cracking, weld undercut, corrosion, dents, gouges, weld scars, incomplete welds, etc. This method is applicable to all visually accessible portions of the tank bottom. Additional details are described in API 650—Section 8.5. Section 9.2.2 of this recommended practice provides additional description of leak location by visually detecting areas of soil-side wicking from a clean bottom.

9.2.2 Evaluation by Wicking Examination of Shell-to-bottom Weld

This is a practical test because it provides information regarding the actual hydraulic integrity of the weld with a product less viscous than the product being stored. A leak could be easily located and repaired. The process of applying a highly penetrating test liquid or dye penetrant to one side of a weld (initial pass or completed weld, as required by the applicable standard of construction or repair) and then letting it stand for at least 4 hours (12 hours is preferred) and observing if it penetrates to the other side of the weld is called a wicking test (see API 650—Section 8.2.4.1 and API 653—Section 12.1.6). Personnel performing this test should have the same visual acuity required for performing other visual methods (see API 653 and ASME *BPVC*, Section V).

9.2.3 Evaluation by Bubble Test Examination—Vacuum

Another method for finding leaks is the vacuum box method, which is particularly useful on the flat bottom of a tank but can also be adapted to the shell and the shell-to-bottom joint. An example of a typical vacuum box is shown in Figure 46 and Figure 47. In this method, the suspect area is first coated with an indicator solution. In cold weather, it is important that the leak-testing liquid be formulated for use at the temperature involved. The open side of the vacuum box with soft rubber gaskets attached is then pressed tightly over the area. A vacuum is developed inside the box by means of a vacuum pump or air ejector connected to the box through a hose. Leaks will appear as bubbles when looking through the glass top of the vacuum box. The method requires a minimum vertical clearance of 6 in. (150 mm) between the bottom and any obstruction for placement of device and accessibility to viewing the local area being examined. Additional details on test implementation are described in API 650—Section 8.6. Some inspection technicians offer an enhancement to this approach by supplementing the methodology with a detectable gas that has been pumped under the bottom (see 9.2.6.1). A detector for this gas is then attached to the vacuum box.

Figure 46—Vacuum Box Used to Test for Leaks

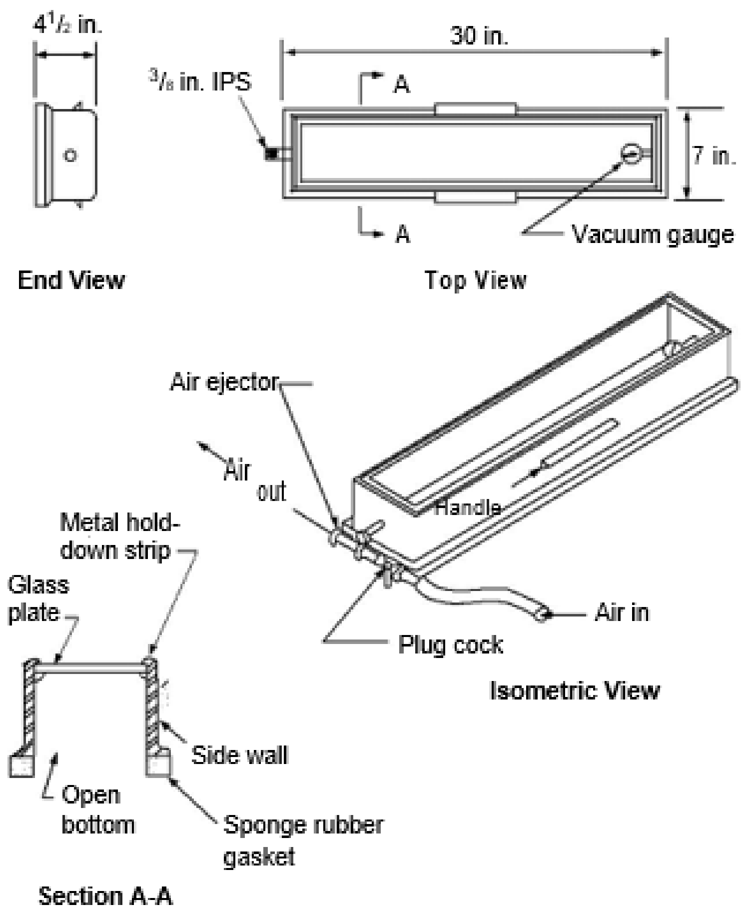


Figure 47—Vacuum Box Arrangement for Detection of Leaks in Vacuum Seals

9.2.4 Evaluation by Liquid Penetrant

Liquid penetrant inspection is an examination method that can be used to locate weld defects, such as cracks, seams, laps, or porosity, which are open to the surface of the weld. Liquid penetrant is applied to the weld where it will enter discontinuities in the surface, primarily by capillary action. The excess penetrant is removed using water or a cleaning agent. The weld is then allowed to dry and a developer is applied. The developer acts as a blotter to draw the penetrant out of the discontinuities back to the surface and as a contrasting background for the penetrant. The dyes are either color contrast (viewable in white light against a contrasting color developer) or fluorescent (visible under ultraviolet or black light). Discontinuities should show clearly as colored marks on a contrast background (visible light type) or a glowing fluorescent mark (ultraviolet light type). This inspection may be used on any weld. The examination may be most useful in areas where other physical weld evaluations cannot be performed due to access limitations. Additional details on exam implementation are described in API 650—Section 8.4. It is not required by API 650 or API 653 but is listed as an owner-operator–specified option.

9.2.5 Evaluation by Magnetic Particle Examination

The weld area to be examined is first magnetized and then ferromagnetic particles are placed on the weld. These will form patterns on the surface of the weld where there are distortions in the magnetic field caused by weld discontinuities, such as cracks, seams, laps, or porosity. The patterns are most evident for discontinuities located near the surface of the weld and oriented perpendicular to the magnetic field. The examination is run a second time with the direction of the new magnetic field set up perpendicular to the old one in order to pick up discontinuities missed in the first pass. The magnetic particles are either color contrasting (viewable in white light) or fluorescent (visible under ultraviolet or a black light) type. The color contrast type is either wet or dry. Discontinuities should show clearly as colored marks (visible light type) or a glowing fluorescent mark (ultraviolet light type). The technology may be used on any weld. The exam may be most useful in areas where other physical weld evaluations cannot be performed due to access limitations. Coatings must be removed for this technique. Magnetic particle inspection is not required by API 650 and API 653 but is listed as an owner-operator–specified option.

9.2.6 Evaluation by Detectable Gas

9.2.6.1 Under-bottom Injection

Another method being used successfully is the injection of inert gas with a tracer element under the tank. An advantage of this method is that welded repairs can be made immediately with the inert gas under the bottom, and a recheck can be made immediately after repairs.

The technology has been applied to existing, replacement, and new tank bottoms. The tank shall be emptied and cleaned prior to the testing. Tank cleaning by abrasive blasting will sometimes cause deep pits or very thin areas to begin leaking when scale or debris is the only material that was preventing leakage. This test method is best suited for uncoated plates or tank plates prior to coating or lining. This method is also well suited for determining the location of leaks in tank plates having a known or suspected leak.

Testing of tank bottoms using a detectable gas beneath the tank plates is accomplished by injecting the gas, which is lighter than air, beneath the tank plates in adequate amounts to allow dispersal over the entire soil-side of the plate. Welding grade helium is a common gas used for this application. This test is performed by detectable gas injection through a standpipe or under-tank telltale piping system using a threaded coupling or other suitable connection. If the tank is not equipped with a leak detection system, or there is no way to inject detectable gas through the leak detection system, detectable gas injection may be accomplished by drilling and tapping holes in the tank bottom. Sampling ports are sometimes drilled in the bottom plates to confirm that the detectable gas has spread across the entire bottom. Once it has been confirmed that the detectable gas has dispersed across the tank bottom, detection instrumentation is scanned over the bottom from the product-side. Instruments capable of detecting a few parts per million (ppm) of the tracer gas are then used for sniffing for leaks on the product-side of the tank bottom as shown in Figure 48. The sensitivity of this test is dependent on the detectable gas concentrations (background) under the tank bottom and type of detection equipment used on the top surface that will help make tracer gas detection more successful.

This method of testing is applicable to 100 % of all bottom plates, welds, bottom-to-shell weld, patch plate welds, clip attachment welds, sump welds, weld scars, tear-offs, or other defects away from welds. Special attention should be paid to three-plate laps and areas of severe deformations.

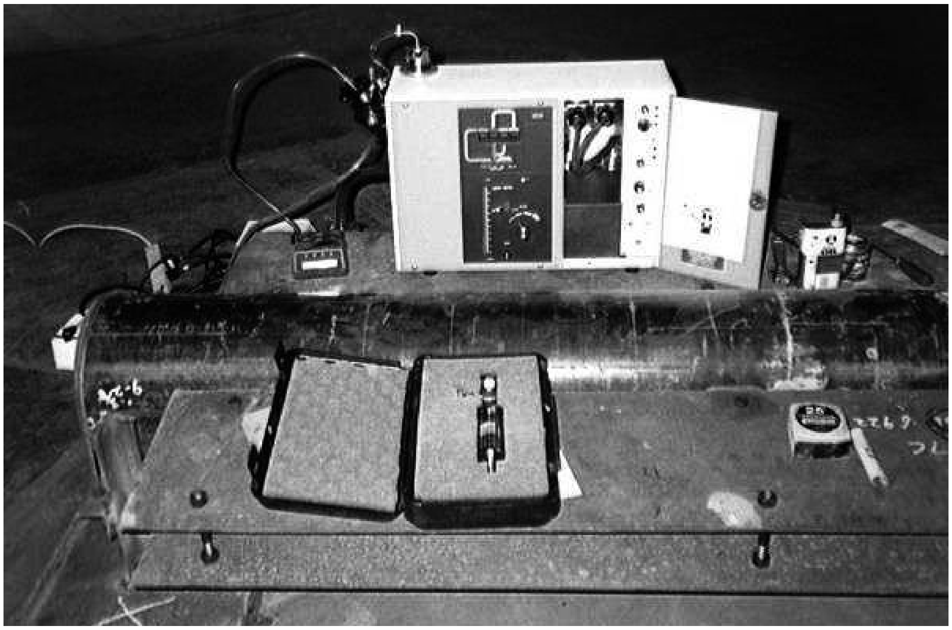


Figure 48—Helium Tester

If the subsurface under the bottom or the interstitial space between double bottoms is below the water table or saturated with water/product/liquid, the dispersal of detectable gas along the soil-side of the bottom plates may be restricted or impossible. Consideration as to the feasibility of the test is required under these circumstances. Dewatering or purging may be viable options to eliminate the problem.

In applying this test method, the inspector and/or technician should consider the design and construction of the bottom. If the bottom is anchored to a concrete pad, such as in a cut and cover or bunkered tank, compartmentalization of bottom plates or bottom sections may exist. In this circumstance, it may be necessary to drill numerous holes in a bottom to ensure complete dispersion underneath. In addition, there is a risk of overpressurization of the tank bottom and possible damage to, or failure of the anchoring system. Consideration as to the feasibility of the test is required under these circumstances.

NOTE Tracer gas detection on tank bottoms is dependent on adequate gas dispersion across (underneath) the area of inspection.

9.2.6.2 Above-bottom Injection

The typical and preferred approach for implementing this leak test is to perform it with liquid in the tank as described in 9.3.2. Liquid loading has two primary advantages:

1) dispersion of the chemical marker is facilitated by the liquid;

2) liquid loading will increase the probability of opening small cracks that might be closed otherwise.

The primary difference between implementing the technology without liquid loading compared with the approach outlined in 9.3.2 is the means of injecting the marker gas. In a liquid-free tank, plastic sheets are taped to the bottom and the marker gas is injected under the plastic. Sampling for gas in the under-tank well system is accomplished as described in 9.3.2. In addition, all of the limitations described in that section with respect to sampling and gas dispersion are applicable for the liquid-free implementation.

9.3 Leak Detection Methods Available During In-service Periods

9.3.1 General

In the discussion that follows, the capabilities and characteristics of leak detection in the context of RPBs are not covered since these systems have been in use for many years and have proven to be effective and require little, if any, maintenance. This section fully describes the key parameters that owner-operators should consider when selecting the appropriate technology for their application. The technology descriptions are presented here in summary form.

9.3.2 Evaluation by Leak Detection Systems Using Volumetric/Mass Measurement Technology

9.3.2.1 General

Leak detection systems based on volumetric and mass measurement technologies are an outgrowth of the automatic tank gauging industry and are a proven system for leak detection for underground fuel storage tanks. They have been in general use for underground fuel storage tanks for several years and as such are widely accepted. Although they have been used commercially in aboveground storage tanks with some success, third-party validation testing is limited.

Both volumetric and mass systems operate on the principle of measuring the amount of liquid in a tank over time while eliminating or compensating for those variables in a tank that are unrelated to a leak. Any liquid loss or apparent volumetric/mass change not attributed to those variables may be considered a leak. These methods have the advantage of directly testing the hydraulic integrity of the tank bottom under near-operational conditions (with liquid in the tank and during the hydrostatic test prior to placing in service). There are several classes of systems, including the following:

a) volumetric level and temperature measurement;

b) mass measurement.

9.3.2.2 Evaluation by Leak Detection by Volumetric Level and Temperature Measurement

Volumetric level and temperature measurement technologies use sensors to measure the level of a liquid in the tank over time. There are two distinct implementations of this technology. In one mode, it is applied to a liquid level of at least 50 % of safe fill height; in the other mode, it is applied to a liquid height of a few feet (meters). This level is converted to volume using strapping charts. Additional sensors may be used to measure the temperature of the liquid (and tank shell) at various points. After eliminating from consideration the volume changes caused by noise (normally occurring events such as tank and fuel growth or shrinkage due to temperature changes), any remaining product volume drop may be considered a leak. The keys to volumetric level and temperature measurement are as follows: first, the measurement of the liquid level, and second, the ability of the system to compensate for noise, primarily change in fluid and shell temperatures.

9.3.2.3 Leak Detection by Mass Balancing

Mass measurement technologies use sensors to measure the pressure of a liquid in the tank over time by use of a differential pressure sensor. When conducting in-service leak tests, the owner-operator should consider the appropriate liquid fill height depending on the application and technology. Additional sensors are used to measure or compensate for the temperature drift of the differential pressure sensor. Other sensors are typically attached directly to the shell to assess diametric changes attributable to temperature change. After eliminating from consideration the volume changes caused by noise (normally occurring events such as tank growth or shrinkage due to temperature changes), any remaining product pressure drop may be considered a leak. The keys to mass measurement are as follows: first, the measurement of the liquid level, and second, the ability of the system to compensate for noise.

9.3.3 Evaluation by Detectable Gas Above-bottom in Liquid Inoculation (Chemical Marker Technology)

9.3.3.1 Application

Detectable marker chemical (inoculate) has been applied to existing, replacement, and new tank bottoms. The tank is full or partially full of product or water prior to testing and may be used on coated plates or on tank bottom plates prior to coating or lining. This test is conducted without disruption of operations and may be useful during acceptance evaluation of a new tank or bottom by inoculating water just prior to the hydrostatic test.

9.3.3.2 Marker Chemical

Testing of tank bottoms using a detectable marker chemical in the tank is accomplished by injecting a volatile chemical into the receipt line, directly into the liquid, or the water draw-off line. The required concentration is a function of the following parameters:

a) mixing of the marker in the liquid;

b) leak detection threshold;

c) sensitivity of detection equipment;

d) composition of the soil under the tank;

e) wait time between inoculation and sampling.

9.3.3.3 Concentration

Typically, an acceptable inoculation concentration is on the order of 1 to 10 ppm. The marker shall be compatible with product purity and comply with any regulations (e.g. non-ozone-depleting; approved for used in motor fuels or fuel for commercial aircraft, acceptable for release into nearby water sources, etc.).

9.3.3.4 Impeded Chemical Migration

If the subsurface of the bottom or interstitial space is below the water table or saturated with water/product/liquid, migration of the marker chemical will be impeded. Two options are available:

1) de-watering or purging prior to sample collection, or

2) extension of waiting time for migration of inoculate in the liquid up to 60 days depending upon conditions and tank size.

9.3.3.5 Detection Tubes

Hollow tubes are installed under the tank bottom to extract air samples for analysis. A tank with secondary containment bottom details may have suitable detection tubes already installed. The under-tank gas collection system should be installed such that the termination point of each pipe covers the entire tank bottom, consistent with the anticipated leak detection threshold and the parameters listed. For many applications, acceptable leak detection performance can be realized with a tube layout so that no part of the bottom is over 20 ft (6 m) in lateral direction from any termination point.

9.3.3.6 Detection Analytical Equipment

The leak detection analytical equipment used to perform leak testing should be in calibration and capable of detecting concentrations consistent with the parameters listed previously. The marker gas detection equipment should be calibrated and tested for sensitivity and proper function throughout testing in accordance with the operating instructions.

9.3.4 Evaluation by Acoustic Emission Examination

9.3.4.1 General

Acoustic emission testing is based on the principle that liquid escaping through a fissure in the tank bottom or shell produces a detectable sound. The demonstration of this principle has shown that two types of sound are produced simultaneously. One type is detectable in the backfill material below the bottom. This impulsive sound extends beyond the audible frequency range and is the distinguishing characteristic signal upon which passive acoustic emission testing is based. The continuous hissing sound, even though it is generated by flow through a fissure, is considered, along with other detectable sounds, to be noise. For acoustic emission testing, noise is defined as any sound, continuous and/or intermittent, that is not a signal. The detection method includes the use of sound sensors that identify the appropriate sounds and therefore the presence of a leak. While this method cannot pinpoint the exact location of the leak, in some instances, when a number of sensors are used, the various signals can be triangulated to indicate the general location, so that more specific methods can be used to pinpoint its location. The acoustic emission test method is theoretically applicable for concurrently testing the parent metal plates, the bottom lap welds, and the sump(s) (e.g. all tank bottom areas wetted by and under the head pressure of the tank contents).

9.3.4.2 Identification of Leak Location

Acoustic systems operate on the principle of detection by location. The basis for identifying a leak, a fissure in the tank bottom through which a fluid is leaking, is the point of origin of the signal. The frequency of an intermittent impulsive signal greatly depends on the condition of the backfill material. Porous materials, such as well-drained sand, could be expected to generate more impulsive signals per unit of time than cohesive materials like well-compacted clay if all other tank conditions were the same. The degree of saturation of water in the backfill also impacts the frequency of signals. If water or hydrocarbon product, possibly from an existing tank leak or possibly from natural characteristics of the foundation backfill and its general drainage, significantly displaces air immediately below the bottom plate at the location of a fissure, the impulsive signals may be reduced completely. The sources of noise, against which a signal shall be discerned, include sounds initiated external to the tank and within the tank. The effects of noise external to the tank can often be avoided by testing during quiet periods, including low activity of nearby operations. Intermittent sounds initiated within the tank structure may be very similar to impulsive signals and shall be accounted for in the reduction and interpretation of the collected data. Lining of the tank bottom prior to running this test may increase the chance that a leak path in a bottom plate or weld will be masked.

9.3.4.3 Sensor

The type of sensor used in acoustic emission testing is an accelerometer, which converts sound energy into measurable electrical output. The sensors are clamped around the periphery of the tank shell, usually at evenly spaced intervals and near the bottom. In some implementations, at least one sensor may be placed at a higher elevation than the others to differentiate sounds initiated at the liquid surface or by the floating roof from sounds initiated at the bottom. In addition, the test operator may choose to cluster some sensors to account for reflected sounds created by echoes from internal piping and structural members. An echo, if undifferentiated from direct signals, causes errors in locating the origin of the signal.

9.3.4.4 Signal Algorithms

For the acoustic test method to be able to indicate signals apart from noise, data collection algorithms and signal processing algorithms are used. The data recorder receiving all raw output from the sensors feeds these electrical outputs to a data collection algorithm to account for predictable unwanted sounds. The algorithm also is used for discrimination of multiple reflections from direct signals. The use of a high-performance algorithm complements the placing of sensors to account for the echo phenomena. The algorithm is configured for known general test conditions of velocity of sound in water or product, diameter of the tank, height of hydro-test water, and spacing of sensors on the shell. The algorithms will typically be able to discern signals and their point of origin.

9.3.4.5 Interfering Signals

The primary limitations of the technology concern the generation of the acoustic leak signal and distinguishing it from other sounds that will occur within the tank environment. The nature and condition of the backfill shall be known because it is an integral part of the acoustic system. Sludge and deposits that settle on the tank bottom may cause signal attenuation and shall be taken into account. The sounds from a floating roof and its sliding seals, though nominally at rest, shall be accounted for. Connected piping shall be considered, as the noise of normal terminal operations, such as pumping or valve actuation, may be transmitted to the tank. Testing during quiet periods of low activity in nearby operations is often the most effective approach. A pre-test waiting period is recommended to accommodate and minimize noise from tank deformation and to allow for tank and foundation deformations that occur because of a change in the liquid height. Potential leaks in under-bottom piping require special attention in the placement of the sensors and may not be detected.

9.3.4.6 Weather Conditions

The effects of weather conditions, such as wind and precipitation, should be considered to minimize weather-related noise. Tests are often put on hold or postponed during periods of adverse weather conditions. The following information should be part of the inspection record from any such acoustic emissions test:

a) date of test;

b) certification level and name of operator;

c) test procedure (number) and revision number;

d) test method or technique;

e) test results and tank certification;

f) component identification;

g) test instrument, standard leak, and material identification.

10 Integrity of Repairs and Alterations

10.1 General

Repairs and alterations to tanks can affect the strength, safety, or environmental integrity of the tank and thus require inspection after the repairs or alterations are completed. It is necessary to make a visual check of all repairs and alterations to see that they have been done properly. In addition, some repairs and alterations may require other types of NDE as specified in API 653. This section will present some typical repairs and the recommended methods of inspection to ensure the integrity of repaired or altered tanks.

Not every flaw or nonconformity will require repair. The decision to repair or not repair should be made by an engineer familiar with storage tank design, construction, and maintenance issues.

10.2 Repairs

10.2.1 Compliance

Before any repairs or alterations are made on tanks, the applicable codes, standards, rules of construction, and jurisdictional requirements should be known, so that the method of repair will comply with all applicable requirements. As a minimum, for guidance on repairs and alterations, refer to API 653—Section 9. All tank dismantling and reconstruction should be performed in accordance with API 653—Section 8 and Section 10, as well as the appropriate sections of API 650. API 653 defines major repairs and repairs that are not major repairs.

10.2.2 Repairs to Welded Tanks

Repairs made by welding on the bottom, shell, or roof of a tank should be conducted and inspected in accordance with API 653—Section 9, Section 11, and Section 12.

All crack-like flaws should be repaired unless an FFS assessment (see API 579-1/ASME FFS-1) or another appropriate evaluation indicates crack-like flaws do not need to be repaired in order to ensure the integrity of the tank. Crack-like flaws in bottom or shell plates should be repaired by chipping, grinding, gouging, or burning the flaw out entirely from end to end before welding. If several crack-like flaws occur in one plate, it may be more economical to replace the plate completely. Welded repairs of crack-like flaws should be inspected carefully to ensure that the cracks were completely removed, especially at the ends of the welded areas, using magnetic particle or liquid penetrant examination, as appropriate.

10.2.3 Repairs to Riveted or Bolted Tanks

Repairs can be made by riveting or bolting, using the procedures given in the original standards for riveted or bolted tanks. In accordance with API 12R1—7.4.1 (a), API 12B factory-coated bolted tanks shall *not* be repaired by welding. If required, bolted tank bottom, shell, and roof panels are simple to repair or replace. Repairs to riveted tanks may also be made by welding if the weldability of the steel is first confirmed by physical testing. At leaking bolted or riveted seams, bolts can be retorqued, rivets can be caulked, re-riveted, rivets (not bolts) can be welded, or abrasive blasted, and coated. Any coating or repair material should be allowed to cure as recommended by the manufacturer before the tank is returned to service. When parts or riveted seams are sealed by welding, the rivets and seams should be caulked for at least 6 in. (150 mm) in all directions from the welding. It should be noted that rivets and seams contaminated with hydrocarbons are difficult to repair by welding techniques. The weld repair may require several attempts and, in some cases, may not be successful in sealing the seam or rivet. Defective rivets can also be replaced by tap bolts, especially in the bottom plates where it is not possible to reach the soil-side of the bottom. When using tap bolts, exercise caution as excess tightening can open new weeps. All repairs that involve caulking, riveting, bolting, coating, and partial welding should be inspected. The typical methods of inspecting repairs to riveted joints include visual, penetrating test liquid, hammer testing, and vacuum box or tracer gas techniques.

When making weld repairs to rivet heads or seams, special procedures that minimize distortion and residual stresses should be followed. These include the following:

a) use small-diameter electrodes;

b) set welding machine at low amperage;

c) keep weld beads small;

d) use back-step bead application;

e) lightly ring-weld rivet heads adjacent to the weld area.

Consider using two-pass welds for rivets and seams that are to be seal welded, to allow for the possibility that the first pass will be poor due to hydrocarbon contamination.

In many cases, the preferred repair method for leaking seams and rivets is the use of a coating. This repair method removes the risk of creating additional leaks in adjacent seams and rivets as the result of shrinkage stresses associated with all weld repairs. It should be noted that leaks typically develop at the stopping point of a welded rivet/lap seam and that junction needs to be dealt with through the application of epoxy sealer, caulking agent, welding, or peening.

10.2.4 Bottom Repairs

For requirements on repairs to tank bottoms, see API 653—Section 9.10.

If the complete tank bottom is being replaced, the replacement plates can be taken into the tank through a slot that is cut in the bottom shell course or they may be brought in through a door sheet and inserted into the slots from inside the tank or they may be lowered into the tank through access created in the fixed roof or external/internal floating roof.

When new bottoms are installed through slots (as illustrated in Figure 49), each sketch plate should be welded in place or securely wedged to the upper part of the shell plate before cutting the next slot. This will prevent the shell from sagging between slots. A perimeter layer of clean sand fill, metal grating, or a concrete pad should be installed under and at least 3 in. (76 mm) beyond the projection of the new bottom so that the shell is supported on the foundation through the new bottom.

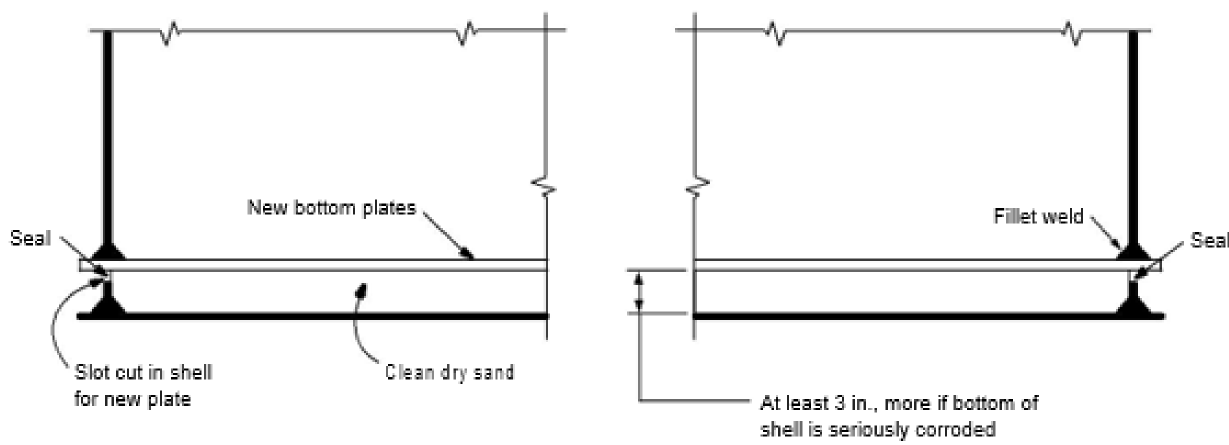


Figure 49—Method of Repairing Tank Bottoms

If the underside of an old bottom has been protected cathodically, or if cathodic protection is planned for a new bottom, the old bottom should be completely removed. If concrete is used as the spacer for a new bottom in conjunction with a nonconductive liner (RPB), then the old bottom may remain in place. If sand or aggregate is used as a spacer, anodes should be installed between the old and new bottoms in accordance with API 651 if the old bottom is not removed. For tanks retrofit with second bottoms and that use a concrete spacer, a cathodic protection system is not necessary for either the old bottom or the new bottom, even if the tank was previously protected by cathodic protection. This is because the old bottom no longer serves as the RPB, but the elastomeric liner that is installed electrically isolates the old bottom from the new bottom and the concrete is not considered corrosive, as well as being better drained than the original foundation.

NDE requirements for bottom repairs and alterations are given in API 653—Section 12 and are summarized in API 653—Table F.1 and API 650. When entire tank bottoms are installed, the NDE requirements are the same as for new tanks constructed to API 650. These requirements include the following:

a) visual examinations;

b) magnetic particle and/or liquid penetrant examinations;

c) vacuum box testing;

d) tracer gas testing;

e) radiographic examinations.

In addition to conducting the above examinations as appropriate, the hydraulic integrity of tank bottoms that have undergone repairs or alterations may be further assessed by applying the testing procedures contained in Section 9.

10.2.5 Shell Repairs

10.2.5.1 Door Sheet

The requirements for shell repairs and alterations outlined in API 653—Sections 9.2 to 9.9 should be followed. Because the reinstallation of door sheets can be difficult for even experienced storage tank engineers, the following procedure is suggested.

a) Locate the door sheet where the bottom plate is reasonably level for a distance of at least 5 ft on either side of the door sheet vertical seams. This will prevent differential bottom settlement due to load transfer when the door sheet is removed.

b) Provide reinforcement to the shell around the door sheet cutout as required to prevent distortion of the shell from the unsupported dead load or wind loads. This reinforcement can be structural shapes welded to the shell.

c) Make the door sheet cuts so that the vertical and horizontal weld joints meet the weld spacing requirements in API 653—Section 9. Leaving a shell lip by making the bottom door sheet cut above the shell-to-bottom weld can provide sufficient stiffness if bottom buckling is a concern. Alternatively, the bottom door sheet cut may be made at the shell-to-bottom joint. This method may require a hydrostatic test of the tank following completion of the repairs.

d) After reinstalling the door sheet, radiograph the weld in accordance with API 653—Section 12.2.

10.2.5.2 Examination Requirements

NDE requirements for shell repairs are presented in API 653—Section 12 and are summarized in API 653—Annex F. These requirements include the following:

a) visual examinations [F.2.1 a) to F.2.1 f)];

b) magnetic particle and/or liquid penetrant examinations [F.3.1 a) to F.3.1 h) and F.3.2];

c) ultrasonic examinations [F.4.1 a) to F.4.1 d)];

d) vacuum box testing [F.5.1 a)];

e) diesel oil testing [F.7.1 a)];

f) air leak testing [F.8.1];

g) radiographic examinations [F.9.1 a) to F.9.1 d) and F.9.1 f) and F.9.1 h)].

10.2.6 Roof Repairs

Roof plates can usually be replaced in the same manner in which they were installed when originally constructed. For further guidance, see API 653—Section 9.11, Section 9.12, and Section 9.13.

NDE requirements for roof repairs and alterations are presented in API 653—Section 12 and are summarized in API 653—Annex F. These requirements include the following:

a) visual examination [F.2.1 c)];

b) magnetic particle and/or liquid penetrant examinations [F.3.1 d)];

c) vacuum box testing [F.5.1 c)];

d) diesel oil testing [F.7.1 b)].

10.3 Special Repair Methods

10.3.1 Epoxy Repairs

When deep pits in tank plates are not closely spaced or extensive and thus do not affect the strength of the tank, they may be repaired or filled by a number of methods. Filling with air-hardening adhesive-to-steel epoxies may be suitable if it will not be affected by the tank's contents. Any other material of a putty-like nature that hardens upon drying can be used for corrosion mitigation; such material must be able to tolerate the tank's contents in addition to making a tight bond with the steel plate. In all cases, the pits should be cleaned thoroughly, preferably by abrasive blasting, and then filled as soon as possible.

The application of epoxies and other thermo-setting resins can provide valuable corrosion protection for storage tank shells, bottoms, roofs, and pontoons. Combined with fiberglass cloth, they provide effective repairs for bottoms, roofs, and pontoons, as well as other low-stress members. See API 652 for more information on lining repairs.

10.3.2 Nonmetallic Repairs

Leaks in cone roofs can be repaired by nonmetallic (carbon fiber materials) or by soft patches that do not involve cutting, welding, riveting, or bolting of the steel. Soft patches can be made from a variety of materials, including rubber, neoprene, glass cloth, asphalt, and mastic or epoxy sealing materials; the choice depends on the contents of the tank and the service conditions. The patching is applied in much the same manner as similar patching would be applied to the roof of a building. The patches may be applied when the tank is in service, if proper safety practices are followed. Figure 50 shows a patch. Complete coating of a cone roof is not recommended because it will be impossible to safely inspect in the future. See API 653—Section 9.4 for guidance on making nonmetallic repairs.

Caution—If soft patches are used that do not restore strength to the roof, they shall be clearly and conspicuously identified so as not to blend into the roof walking surface, creating a hazard for personnel.

Figure 50—Temporary "Soft Patch" Over Leak in Tank Roof

10.3.3 Safety Considerations

It should be noted that if large areas of patching are used, then consideration to personnel safety and the possibility of fall-through becomes likely for persons working on roofs repaired in this manner. In addition, be aware that should parts of the repair materials be dropped into the tank while making these repairs, or while the tank is in service, this can lead to hazards if these parts enter piping and pumping systems and cause blockages, seal failures, and/or fires or other process-related problems. These repairs should be inspected at intervals that are shorter than conventional permanent repairs. Soil foundations that have washed out or settled under the bottoms of atmospheric storage tanks can be repaired by pumping sand, drilling mud, clay, lean concrete, or similar material under the tank. Material can be pumped through holes cut in the tank bottom. In some cases, it may also be necessary to raise the tank with jacks (as shown in Figure 51). It should be noted that while these repairs are possible, they may cause problems in some cases because of localized pressure from the pumping or grouting process, resulting in yielding and bending of bottom plates in an uneven, local mode. The experience of the contractor performing the work may be a significant variable.

Figure 51—Tank Jacked Up for Repairing Pad

11 Records

11.1 General

Good records form the basis of an effective inspection program and are the key component to ensuring that accurate evaluations and inspections are carried out in the future. Accurate and complete records are used to predict when repairs and replacements may be needed, reducing the potential for safety and environmental hazards. Accurate records may also be used when information is needed for new tank specifications.

11.2 Records and Reports

A complete record file should consist of at least three types of records:

a) design and construction records;

b) repair/alteration records;

c) inspection records.

Refer to API 653 for a description of these types of records. Records maintained throughout the service life of each tank shall be updated to include new information pertinent to the mechanical integrity of the tank. Inspection reports (or information stored in data management systems) shall document the following:

a) the date of each inspection;

b) the date of the next scheduled inspection;

c) the name of the person who performed the inspection;

d) a description of the inspection performed;

e) the results of the inspection;

f) tank identification number or another label;

g) description of tank type.

The following is additional information or documentation that should also be included (but not required):

a) contents and specific gravity;

b) design operating temperature;

c) overall dimensions;

d) materials of construction;

e) design codes and standards used;

f) nozzle schedule;

g) corrosion allowance;

h) postweld heat treatment requirements and reports;

i) type of supports;

j) coating and insulation requirements;

k) fabrication documents, such as welding procedures and welder qualifications;

l) design calculations;

m) manufacturer's data reports;

n) reports on periods of abnormal operation (e.g. process/system upsets, such as elevated pressures, high temperatures, or fluid concentrations outside the operating limits that might affect mechanical integrity of the tank), including an analysis of the vessels integrity due to the abnormal operation;

o) FFS assessment documents (see e.g. API 579-1/ASME FFS-1).

Any method that retains the data and documents the associated results and conclusions of the inspection is an acceptable form of recordkeeping. This does not necessarily require an all-paper or all-electronic media system. For example, video equipment and verbal discussion may be an acceptable format when used correctly. Any combination of various media may be used as long as it supports the purpose of the inspection.

Inspection records should be readily available. In situations where records are kept in a remote or central location, the records should be accessible at the facility.

11.3 Form and Organization

The inspection reports required by API should be organized in a convenient manner and as requested by the owner-operator. This usually means an Executive Summary up front, a statement as to whether the report is an external or internal inspection and other relevant information such as the facility name, the tank number, etc.

The report should clearly indicate the following categories of recommendations:

a) those areas that require immediate repair or change that are mandatory in order to maintain the continued safety, health, and environmental concerns of the facility and that should not be delayed;

b) those areas that should be repaired to extend the tank life that may fail before the next internal inspection;

c) those areas that can be deferred until the next internal inspection without jeopardizing health, environment, or safety and that the owner-operator wants to defer;

d) those items that are strictly nonthreatening areas of concern such as cosmetic issues, settlement that is within the API 653 tolerances.

All recommendations should have supporting calculations, photos, and rationale included in the final report.

Annex A
(informative)

Selected Nondestructive Examination Methods

A.1 Ultrasonic Thickness Measurement

Ultrasonic testing may be used in conducting inspections. In the context of tank inspection, it is typically used for thickness determination. It should be noted that ultrasonic testing is not required because any method that establishes corrosion rates may be used. When ultrasonic testing is applied and the corrosion rate is not known, then the maximum interval between inspections is specified in API 653—Section 6. Other methods that may be used for determination of corrosion rates include similar service, corrosion coupons, use of more conservative corrosion rates by substituting bottom corrosion rates for shell corrosion rates, etc.

It is recommended that the ultrasonic instrument have an “A-scan” display with a digital readout. UT measurement should be performed using a transducer with characteristics appropriate for the particular test to be performed.

Dual-element transducers are frequently selected, and they are available with many different operating ranges. Dual-element transducers may have the ability to measure thin sections from 0.050 in. to 1.000 in. (1.3 mm to 25 mm). The limitations of transducers that should be recognized are that their range is finite and the transducer frequency is high enough to measure thin sections accurately. Holes in the material or sections of less than 0.050 in. (1.27 mm) will provide either no reading or a false reading when measured with too low a frequency.

Further, if the material being tested is coated, procedures shall be employed to account for the coating thickness. The dual-element transducer will read the thickness of the coating in addition to the thickness of the base metal. The effect of the coating on the overall thickness measurement will depend on the difference in the velocity of ultrasonic wave propagation between the base metal and the coating material. This difference may be significant in some cases. For example, epoxy coatings have a wave velocity approximately half that of the steel; therefore, the ultrasonic tool will measure 0.015 in. (15 mil) of epoxy coating as 0.030 in. (30 mil) of steel. Selection of a single-crystal transducer operating in the so-called echo-to-echo mode can prevent this coating thickness error. The single-crystal transducer has poor resolution for small-diameter deep pits. Many echo-to-echo measurement devices now generally available eliminate the need to compensate for the coating thickness during measurement. Once properly calibrated, the multi-echo technique produces direct readings through coatings up to approximately 0.080 in. to 0.100 in. (80 mil to 100 mil) thick without loss of accuracy. The echo-to-echo mode is sometimes difficult to use for measuring the thickness when the backside is heavily corroded because the loss in signal caused by the corrosion may prevent resolution of the second back-wall echo. Currently, some UT transducers and gauges for thickness measurement offer the ability to measure coating thickness and remaining wall thickness simultaneously. UT measurements on tank bottoms, shells, and roofs should carefully distinguish between thickness loss and mid-wall laminations. When used with UT flaw detectors and/or thickness gauges, standard thickness transducers can be used to view the “A-scan,” which can be effective for this purpose.

A.2 Ultrasonic Corrosion Mapping

Many automated ultrasonic corrosion mapping units that enable areas to be scanned with high-resolution repeatability are available. Typical automated ultrasonic testing equipment as shown in Figure A.1 is used for this purpose. Selection of the correct transducer size and frequency is critical to examination resolution. ASME recommends 10 % minimum overlap for readings based on the transducer diameter. Large-diameter transducers will not find small-diameter deep corrosion pits. Some scanning techniques can illustrate very thin sections or holes as dropout regions in the data plot. Phased array ultrasonics is now used for thickness mapping and provides ultra-high data point density, which helps in detection, characterization, and discrimination of mid-wall anomalies from loss of wall thickness.

A.3 Ultrasonic Angle Beam Testing

Angle beam ultrasonic (shear and high angle L wave) inspection can be used to assist in the discrimination between laminations and inclusions in material. Automated angle beam ultrasonic examination is especially effective for this purpose. The most general application of angle beam transducers is to detect defects in butt-welded joints, usually in lieu of radiography.

A.4 Floor Scanning Inspection of Tank Bottoms

Tank bottom scanning has become a commonly used technique to effectively evaluate a large portion of the tank bottom for both top- or product-side corrosion and bottom- or soil-side corrosion. Typically, a bottom scan can cover a majority of the tank bottom, excluding areas adjacent to welds and other obstructions. While this varies, typically 80 % of the bottom can be successfully inspected, which can be increased using complementary techniques. Since the inception of MFL scanners, the ability to scan a large portion of tank bottoms has been available. This is a major improvement in inspection capability for tank bottoms because of the random nature of tank bottom soil-side corrosion. Additionally, a number of other inspection technologies have become available, such as low-frequency eddy current, remote field eddy current, partial saturation low-frequency eddy current, and a combination of both MFL and eddy current technologies. See Figure A.2 for an example of a bottom scan unit. The user should make sure that the scanner is calibrated properly and has a validation and/or calibration test plate, which will ensure that the test area is inspected uniformly over the width of the scanning head. A primary advantage of these tools is the ability to detect product-side pitting, soil-side corrosion, and holes in the tank bottom in an efficient and economical manner.

It should be noted that simply scanning over the area does not ensure detection of all metal loss as all systems have detection thresholds. The owner should determine what the minimum detection threshold is and factor this into the overall assessment. Furthermore, these systems require some additional inspection to quantify detected flaws. Typically, an ultrasonic examination method is used for such prove-up work. Section 8.5.5 provides additional details. Figure A.3 shows a typical ultrasonic testing scrub area scan to detect tank bottom soil-side corrosion. Figure A.4 shows guided wave ultrasonic testing being performed on piping. Such equipment is also used to help establish the extent of soil-side corrosion. There can be considerable variability on the quality of these inspections. Industry experience shows they can be highly effective when operators with the proper training and experience use machines with suitable detection capabilities. Most scanners and procedures require operators to optimize sensor and magnet standoff from the bottom plates. Moreover, operators can determine the suitable sensitivity settings by follow-up ultrasonic examination in order to optimize detection settings. Follow-up ultrasonic examinations are critical for an effective MFL bottom scan inspection depending on the equipment manufacturer specifications. At owner-operator's request, MFL operators and ultrasonic testing technicians may be required to be qualified per ASNT SNT-TC-1A, and/or performance demonstration testing of the MFL operator may be required prior to an MFL scan in order to increase the probability of detecting and accurately sizing corrosion.

A.5 Robotic Inspection

Tools for internal tank inspection used while the tank is in service have been developed. These robotic crawler devices are designed for total immersion in liquids and have been successful in providing UT information on tank bottoms in clear finished product storage such as gasoline, naphtha, jet fuel, No. 4 and No. 6 fuel oils, condensate, and some crude oil. This equipment needs to be used under carefully controlled circumstances and within API safety guidelines for work on tanks in service. See Figure A.5 for an example of a robotic inspection tool. The technology has been utilized in a wide variety of products including, but not limited to, crude, diesel, jet, gasoline, lube oil, benzene, hexane, boiler feed water, and chemicals. Of course, the owner-operator needs to conduct a review of safe operating procedures prior to performing robotic inspection. The robotic inspection process can acquire a large density of measurements over an analyzed area, which can total hundreds of thousands of UT measurements. This enables an evaluation using statistical methods to extrapolate the thinnest remaining metal of the entire bottom. Some robotic equipment can also perform adequate inspection on other portions of the tank and accessories (bottom settlement, a visual inspection of the vapor space, and a visual inspection of the tank bottom).

Figure A.1—Automatic Ultrasonic Testing

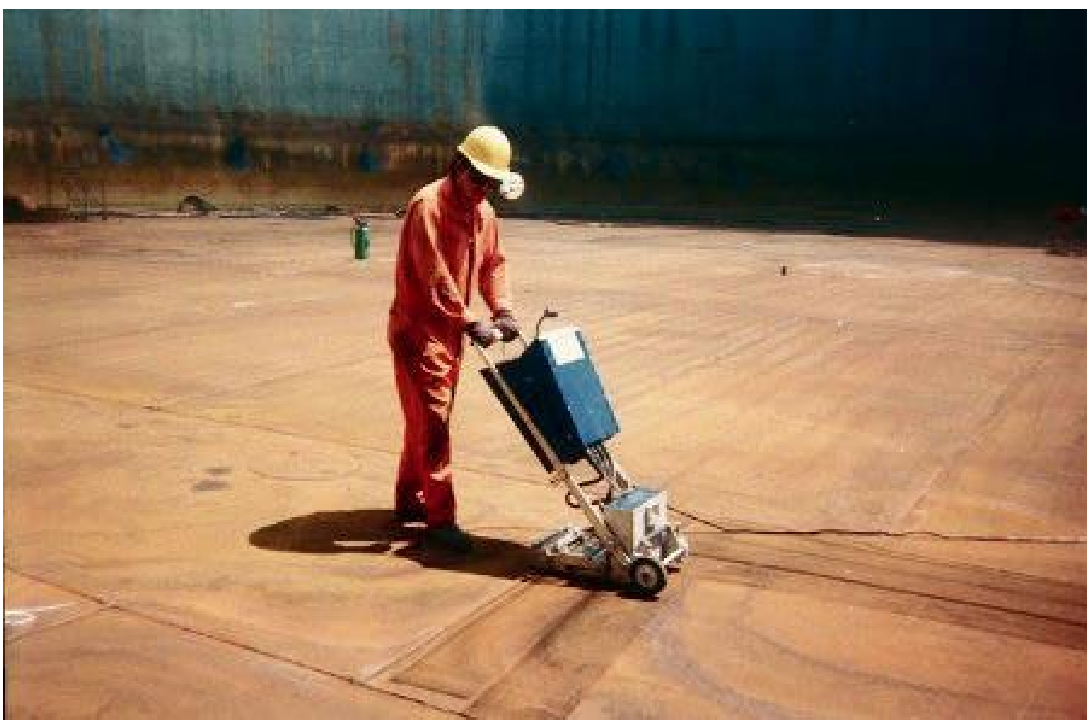


Figure A.2—Magnetic Flux Leakage Scanner

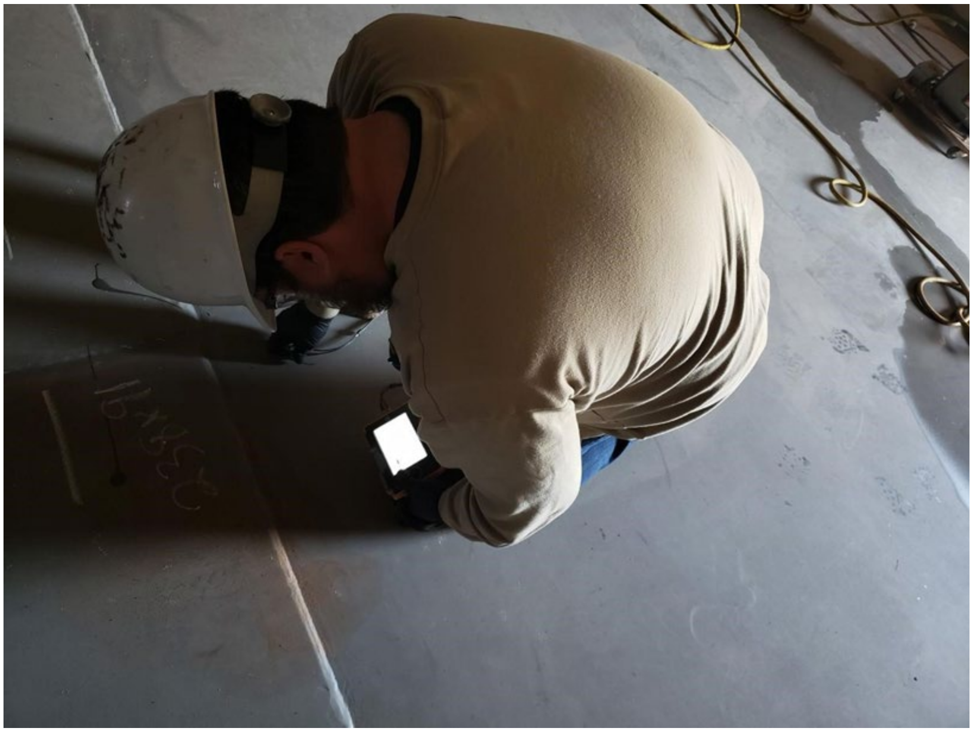


Figure A.3—Ultrasonic Examination

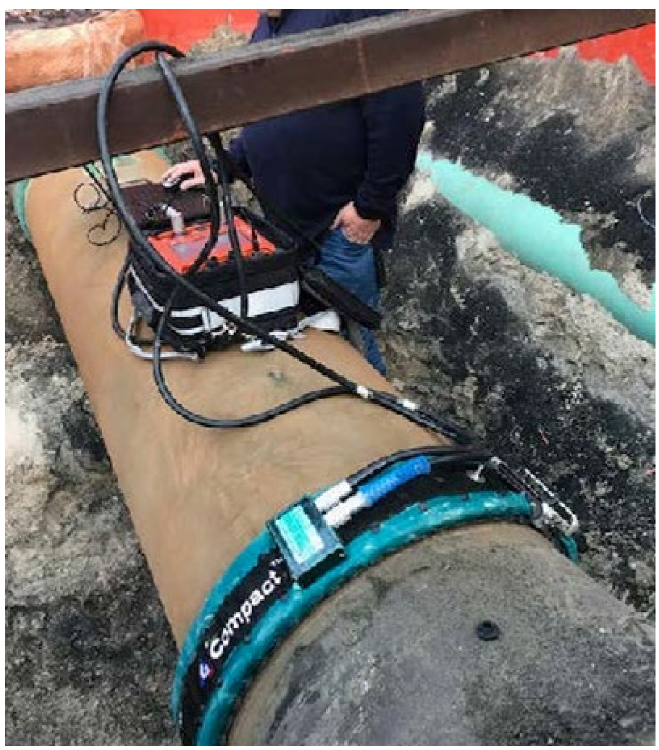


Figure A.4—Guided Wave Ultrasonic Testing

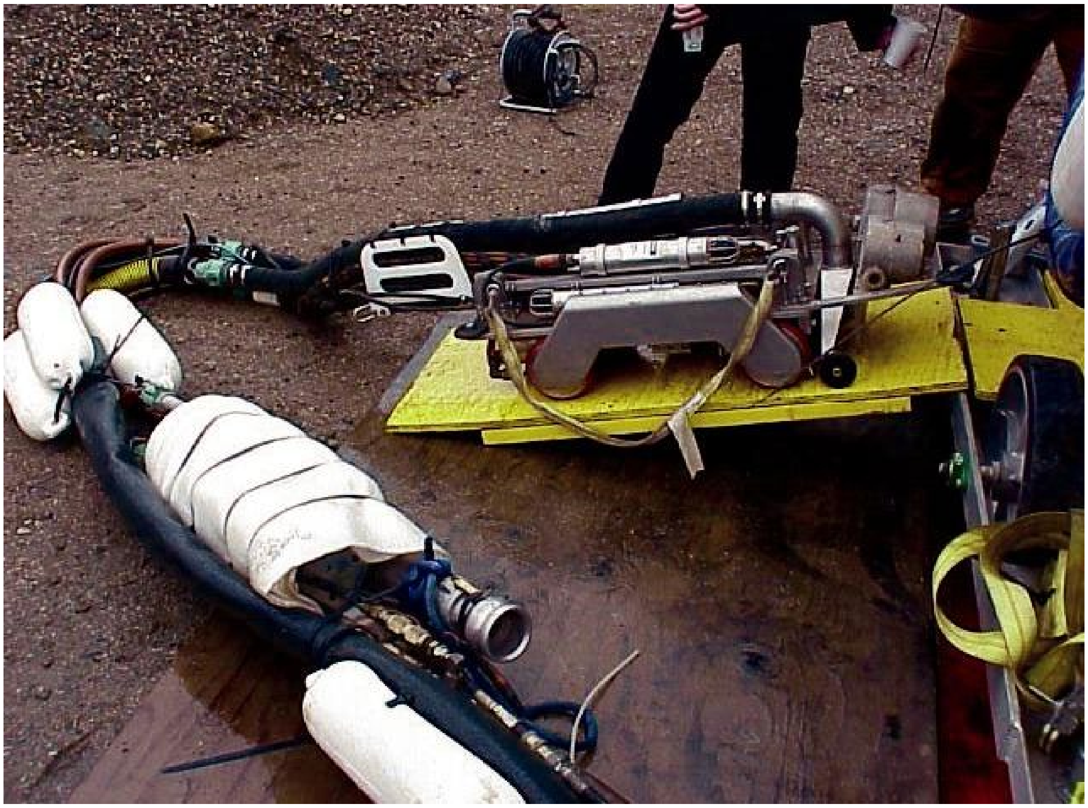


Figure A.5—Robotic Inspection Tool

Annex B
(informative)

Similar Service Evaluation Tables

Table B.1—Selected Considerations for Performing Similar Service Assessments

Factor	Range	Comment
Product-side		
Stock	Can range from nil to very high rates; corrosion can be in form of pitting or general thinning or both.	Hydrocarbon stocks typically result in corrosion rates of 1 mil to 3 mil (0.025 mm to 0.076 mm) per year for finished fuels. Aviation gas may be 2 to 3 times this amount. Crude oils have variable rates of corrosion. It is important to apply similar service to similar stocks, preferably the same stock, unless it can be demonstrated that the extrapolation of corrosion rate from one stock to another is warranted. Some products are more prone to MIC.
Temperature	Stock temperatures can be divided into two cases: (1) ambient tanks and (2) heated or refrigerated tanks. Most petroleum tanks are ambient temperature. For heated tanks, most are below 500 °F (260 °C). Asphalt tanks are typically the highest temperatures and are typically at about 500 °F (260 °C). Refrigerated tanks vary from ambient down to cryogenic temperatures.	Temperature is a critical factor when using similar service because reaction rates typically double for every 18 °F (10 °C) increase in temperature. This increase due to higher temperature also applies to corrosion rates. For ambient tanks, note that tank location will impact ambient storage temperature to a degree.
Water bottoms	Some tanks have no water bottoms (e.g. asphalt tanks or lube oil tanks); other tanks have very aggressive water bottoms such as crude oil tanks; finished fuel oil tanks may have water bottoms, but the corrosion rates can be variable.	For tanks with immiscible water that settles below the product, internal tank bottom corrosion rates may be primarily controlled by the chemical composition of the water bottoms and basic factors, such as pH. Application of similar service for tanks with should be based on product produced by the same or a similar manufacturing plant or process if the water chemistry of the water is not known.
Bottom design	The design of the tank bottom will impact the ability to remove all water bottoms or other phases and debris that can rest on the bottom and accelerate corrosion. Bottoms range from flat, to cone-up, cone-down, or single slope. The slope itself can vary. The use of a foundation and ringwall will impact the long-term ability of the tank bottom to retain the design drainage patterns.	It should be realized that even if water is removed regularly and the tank is designed for water removal, depending on the quality of the tank bottom and the design, some water cannot be removed. In this case, the tank essentially carries water, and the use of similar service should assume that there is water present on the bottom. Water is never completely removed as far as MIC is concerned. However, weekly water draws are performed to ensure that as much water is removed as possible; in addition, a water-sensing probe is installed in the tank bottom to ensure that water does not exist.
Internal lining	Ranges from unlined to fully lined. Linings range from a thin-film to a reinforced thick-film. The general classifications of linings are thin-film, thick-film, and reinforced thick-film. The selection for the lining system is dependent upon the product being stored, temperature of operation, and the condition of the tank.	Linings are used to prevent corrosion from occurring and are applied to the areas of a tank that are susceptible to corrosion. The areas of the tank that are commonly lined are the tank bottom and 2 ft to 3 ft (61 cm to 91 cm) up the shell; the roof and down the shell to the liquid level; and local bands of the shell at the liquid vapor interface. In addition, some tanks are fully lined to prevent corrosion and to improve product quality. Effective linings can reduce product-side corrosion. Factors that increase the life of a properly selected lining system are outlined in API 652. If factors (e.g. material selection, surface preparation, application among others) are not properly performed, they can reduce the effectiveness of the lining and projected life of the coating.

Table B.1—Selected Considerations for Performing Similar Service Assessments *(continued)*

Factor	Range	Comment
Product-side		
Internal cathodic protection	Typically, only applied to water storage tanks without internal linings.	A tank with internal cathodic protection vs one without can have significantly different corrosion rates.
Soil-side		
Foundation material	Concrete ringwall, concrete slab, engineered fill, native soil.	Concrete is alkaline and tends to reduce corrosion rates as compared to typical soil. Since soil and fill corrosion rates are site specific, similar service should be limited to experience with the same site or sites with higher corrosion rates and use of the same tank pad material.
Release prevention barrier (RPB)	Double bottoms, plastic liner under tanks, lined secondary containment.	Tanks with double bottoms have the new bottom elevated at least 4 in. (10 cm) above the old bottom and therefore standing water corrosion is reduced. Tanks that have RPBs or liners installed under and around the tank bottoms are more likely to trap water and thus increase corrosion. Similar service must consider the impact of standing water and drainage that results from use of RPBs.
Drainage	Poor, stagnant to well drained.	Drainage is impacted by foundation design, native soil, RPBs, and by original design for drainage.
Isolation from old bottom	Isolation means electrical insulation of the old bottom to the new bottom by use of a nonconductive membrane. Since new steel is anodic (more corrosive) than old steel, many improperly installed double bottoms are subject to a corrosion life for the new bottom, which is shorter than that of the original old bottom.	Similar service must be based on knowledge of whether the tank being compared has a double bottom that is isolated or not.
Cathodic protection	Cathodic protection systems for tank bottoms can be galvanic or impressed current. Impressed current systems have a prolonged life but shall be maintained. Galvanic or sacrificial systems do not need to be maintained but have a finite life. The effectiveness of both systems depends on proper installation.	Use of similar service should only be applied to cathodic protection systems of the same kind (i.e. galvanic, impressed current). Additional considerations apply primarily to verification that the cathodic protection system is effective.

Table B.2—Similar Service Example for Product-side Corrosion

Product-side	Variable		Corrosion Characteristics
	Existing Tank	New Tank	
Stored liquid	Gasoline	Gasoline	Same
Temperature	Ambient	Ambient	Same—based on same location. Note if similar service is being used for different locations, then the average ambient temperature difference should be evaluated to see if it is important in the similar service analysis. Typically, it will not be unless the temperature difference is greater than 10 °F (5.5 °C).
Water bottoms	None	None	Same—weekly water draws are performed to ensure that water bottoms are removed; in addition, a water-sensing probe is installed in the tank bottom to ensure that water does not exist.
Bottom design	Cone-up	Shovel bottom	Same—both bottom designs are sloped to remove water.
Internal coating	Not coated	Bottom and up 2 ft (61 cm) on shell coated	Conservative—new design will be more conservative than old; therefore, corrosion rate will be less than the old tank.
Cathodic protection	No cathodic protection	No cathodic protection	Same

Annex C
(informative; normative if used)

Less Common Tank and Roof Designs

C.1 Plain and Noded Spherical Tanks

Tanks with a plain spherical roof and tanks with a noded spherical roof are shown in Figure C.1 and Figure C.2, respectively, and cross-sectional view is shown in Figure C.3. Figure C.4 shows a plain spheroid, whereas Figure C.5 shows a spherical roof with a knuckle radius or smooth transition at the intersection of the shell and top head.

Figure C.1—Plain Hemispheroids

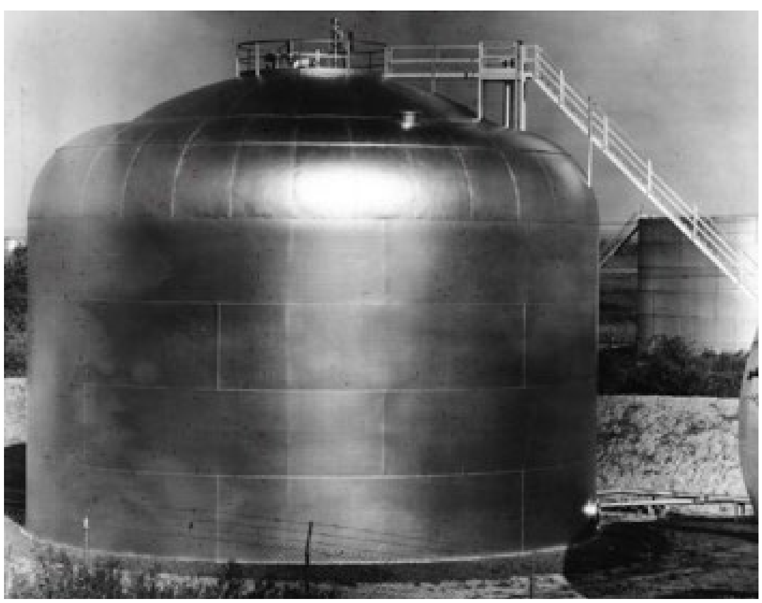


Figure C.2—Noded Hemispheroid

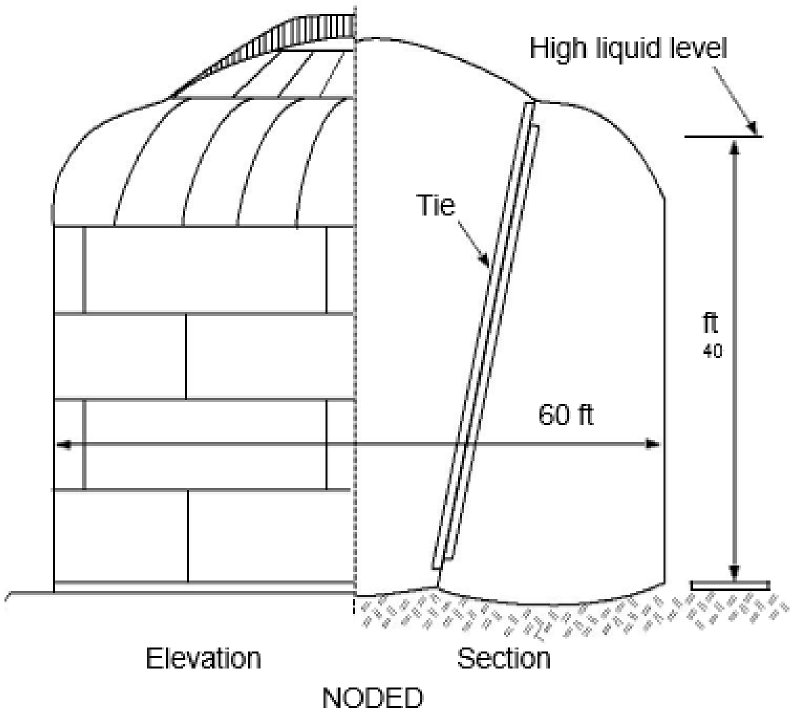


Figure C.3—Drawing of Hemispheroid

Figure C.4—Plain Spheroid

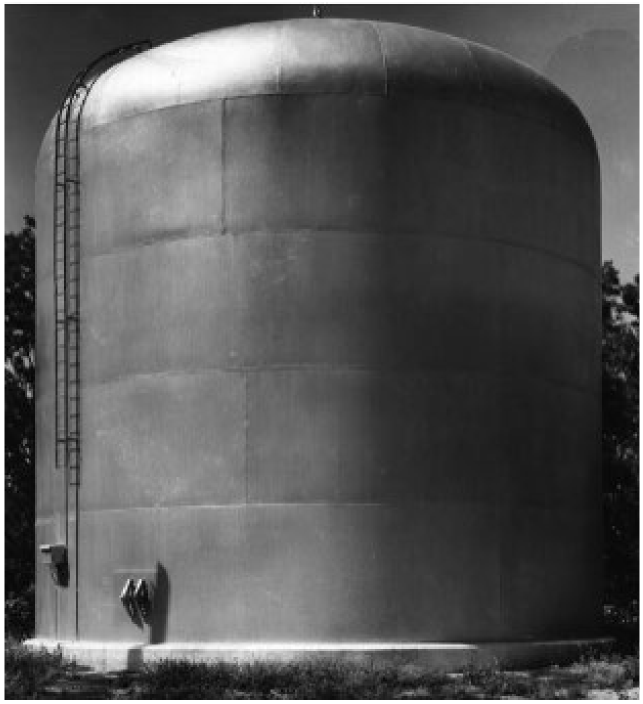


Figure C.5—Plain Hemispheroid with Knuckle Radius

C.2 Spheroids

The spheroid uses elements of different radii, resulting in a somewhat flattened shape as shown in Figure C.1. The noded spheroid, shown in Figure C.6, is used for larger volumes, and internal ties and supports help distribute the shell stresses. Figure C.7 shows a cross-section of a noded spheroid. Noded spheroids are no longer constructed; they have been replaced either by spheres or by vertical cylindrical storage tanks as referenced in API 620.

Figure C.6—Noded Spheroid

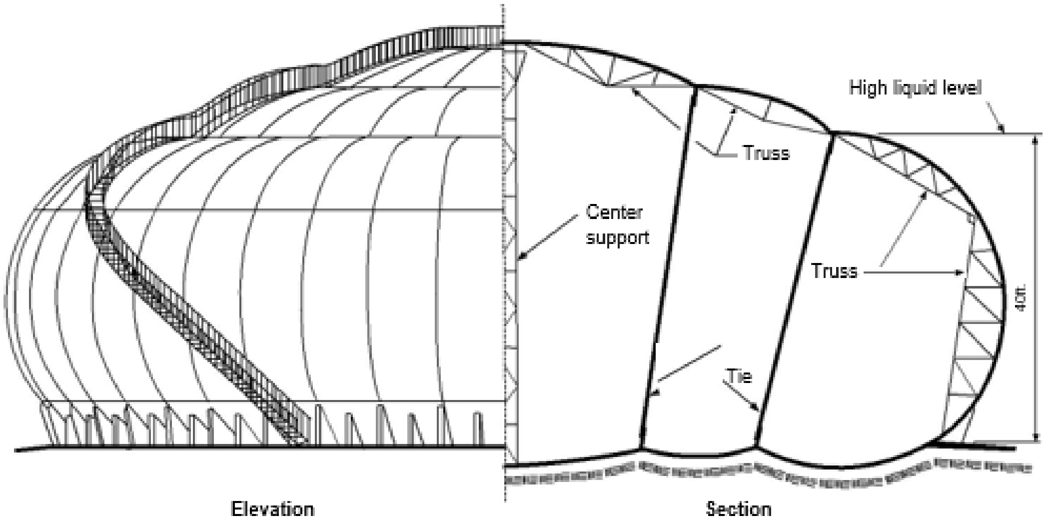


Figure C.7—Drawing of Noded Spheroid

C.3 Other Roof Designs

C.3.1 General

Other less commonly used atmospheric storage tank roof details include the lifter-type roof and the breather-type roof.

C.3.2 Lifter-type Roof Tanks

Lifter-type roofs prevent vapor losses from the tank by means of liquid or dry seals. Liquid-seal lifter roofs have a skirt on the roof edge that fits into a trough filled with liquid. Dry-seal lifter roofs have a flexible membrane connected to the tank wall and a skirt on the roof edge. In these two lifter-type roofs, the roof is free to move up and down within limits as the tank is filled and emptied or when a change in temperature causes vaporization of the stored product. These types of lifter-roof tanks are less commonly found in service today than in the past.

C.3.3 Breather-type Roof Tanks

In the breather-type roof, a number of methods are used to provide expansion space for vapors without using a loose external roof. The plain breather-type tank (shown in Figure C.8) has a flat roof that is essentially a flexible steel membrane that is able to move up and down within rather narrow limits. The balloon-type roof (shown in Figure C.10) is a modification of the plain breather-type roof that is capable of a greater change of volume. A tank with a vapor dome roof (shown in Figure C.9 and Figure C.11) uses an added fixed dome with a flexible membrane attached to the walls that is free to move up and down. This type of vapor roof may be designed to provide for any desired change in volume. Vapor recovery systems may use this type of tank.

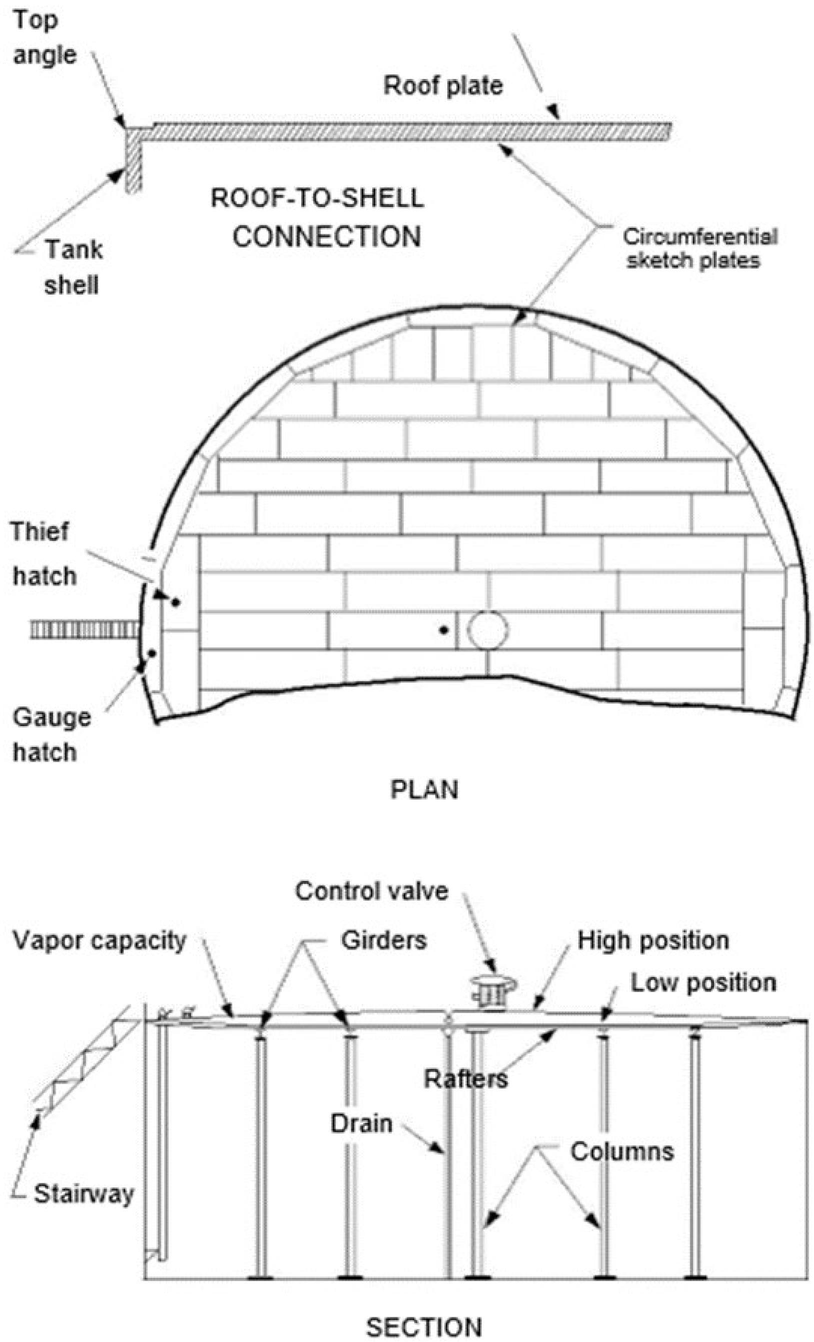


Figure C.8—Plain Breather Roof Tanks

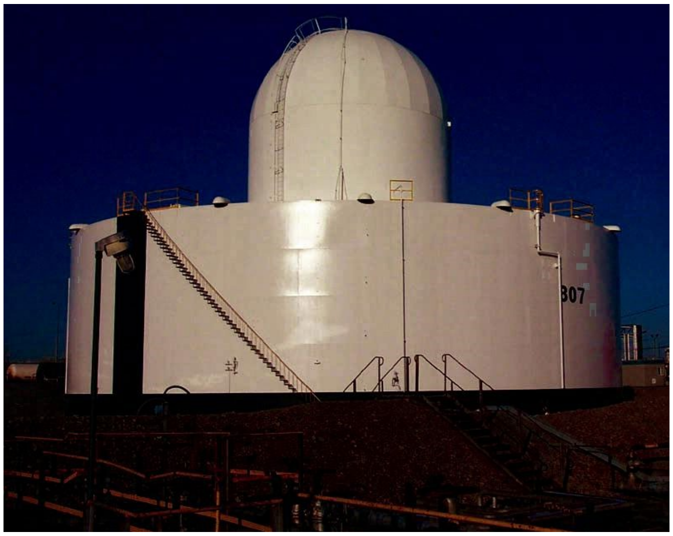


Figure C.9—Tank with Vapor Dome Roof

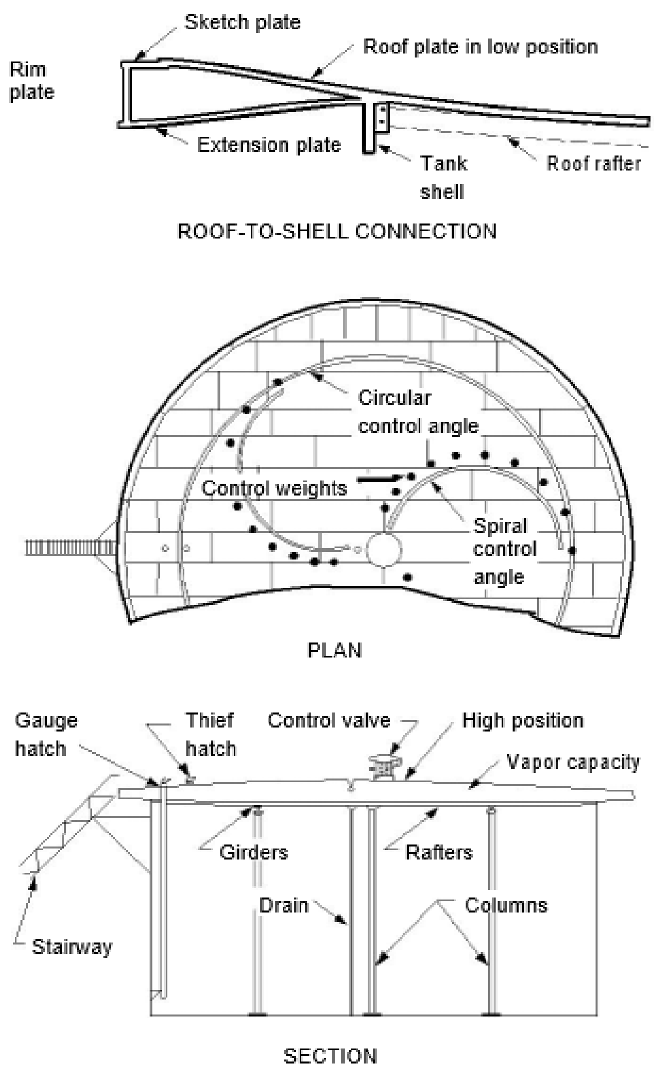


Figure C.10—Balloon Roof Tank

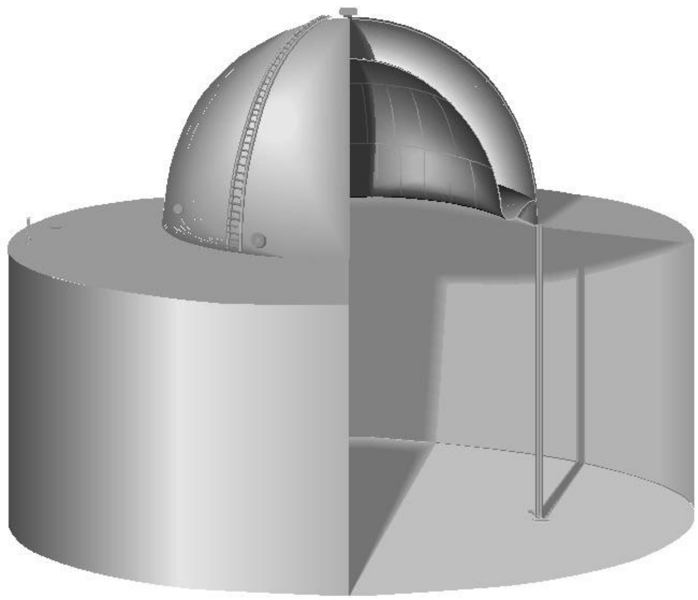


Figure C.11—Cutaway View of Vapor Dome Roof

C.4 Deterioration of Other Than Flat Bottom and Non-steel Tanks

C.4.1 General

Tanks can be constructed of materials other than carbon steel. Aluminum (see API 650—Annex AL and obsolete aluminum tank standards ASME B96.1 through 1999, and API 12G, First Edition, 1957), stainless steels (see API 650—Annex S) and other alloys (see API 650—Annex X for duplex steels), wood, fiberglass (see API 12P), and rarely wood (formerly API 12E), and concrete tanks can occasionally be found in refineries, chemical plants, and terminals and in oil production liquids service.

C.4.2 Wooden Tanks

Tanks constructed of wood are rare today but were addressed in API 12E (now obsolete). Tanks constructed of wood can rot unless they are adequately protected. They also can deteriorate from infestation by insects, such as termites. Unless kept continually moist, these tanks can shrink and can leak when refilled. If steel bands are present, the bands can be subject to atmospheric corrosion and can loosen under repeated cycling. Some wooden tanks are still operated in oil production fluids service and wooden tanks have been built with structurally supported aluminum dome roofs in accordance with API 650—Annex G.

C.4.3 Concrete Tanks

Concrete tanks can be attacked by the tank contents, crack because of ground settling or temperature changes, or spall due to atmospheric conditions, resulting in exposure of the steel reinforcement to further atmospheric corrosion.

C.4.4 Non-steel Metal Tanks

Tanks constructed of materials such as aluminum, stainless steels, and other alloys are usually used for special purposes, such as food processing (for product purity), or because of product corrosion concerns. They are subject to some of the same mechanical damage mechanisms as carbon steel tanks. In addition, external SCC of stainless steel tanks should be a concern if chlorides in insulation get wet and attack the stainless steel. Aluminum can be affected by impurities such as acids or mercury compounds in process streams or wastewater.

C.4.5 Alternative Tank Construction

Tanks can also be constructed of details that are not vertical, cylindrical, or flat bottomed. These tanks are usually classified as horizontal (axis of tank is in horizontal plane), skirt-supported, or column-supported with cone bottoms (with a vertical major axis). These latter tanks can be classified as bins or silos and very often hold granular or non-petroleum liquids or solids such as grain, cement, process liquids, carbon black, coker fines, and similar materials. Bins and silos, especially in granular product service, can suffer mechanical damage in operation including shell deformation and fatigue (from agitators or vibrators). Due to moisture entrapment, horizontal tanks on saddle supports can experience external corrosion at the saddle-to-tank interface. These areas are often inaccessible and difficult to inspect with normal inspection methods.

C.4.6 Variations

It is not possible to present all of the different or specific details that can be present in wooden tanks, concrete tanks, or steel bins and silos in this document. Careful examination and assessment should be planned based on prior inspection or similar service issues, type of construction details, and materials of construction. Structural integrity assessment shall require use of a qualified engineer familiar with the type of tank design and operation in question.

Bibliography

General

Familiarity with these documents is suggested as they provide additional information pertaining to the design, inspection, evaluation, and repair of aboveground storage tanks. API takes no responsibility for the relevance, content, or accuracy of the publications listed herein. There has been no attempt to determine if each article is appropriate for listing in this recommended practice.

API Publication 300 Series

— API Publication 306, *An Engineering Assessment of Volumetric Methods of Leak Detection in Aboveground Storage Tanks*

— API Publication 307, *An Engineering Assessment of Acoustic Methods of Leak Detection in Aboveground Storage Tanks*

— API Publication 315, *Assessment of Tankfield Dike Lining Materials and Methods*

— API Publication 322, *An Engineering Evaluation of Acoustic Methods of Leak Detection in Aboveground Storage Tanks*

— API Publication 323, *An Engineering Evaluation of Volumetric Methods of Leak Detection in Aboveground Storage Tanks*

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