NFPA® 59A

Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG)

2019

NFPA®

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NFPA® 59A

Standard for the

Production, Storage, and Handling of Liquefied Natural Gas (LNG)

2019 Edition

This edition of NFPA 59A, *Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG)*, was prepared by the Technical Committee on Liquefied Natural Gas. It was issued by the Standards Council on November 5, 2018, with an effective date of November 25, 2018, and supersedes all previous editions.

This edition of NFPA 59A was approved as an American National Standard on November 25, 2018.

Origin and Development of NFPA 59A

A committee of the American Gas Association began work on a standard for liquefied natural gas circa 1960. In the autumn of 1964, a draft was submitted to NFPA with the request that it be considered as the basis for an NFPA standard. The Sectional Committee on Utility Gas prepared a standard that was adopted tentatively at the 1966 NFPA Annual Meeting at the recommendation of the Committee on Gases.

With the formation of the Committee on Fuel Gases in the summer of 1966, the standard was assigned to that committee and its subcommittee on Utility Gas Plants. The first official edition was adopted at the 1967 NFPA Annual Meeting under the sponsorship of the Committee on Fuel Gases.

By early 1969, it was apparent that the use of LNG was expanding considerably beyond the utility gas plant applications covered by the 1967 edition. The American Petroleum Institute suggested that one of its standards, PUBL 2510A, *Design and Construction of Liquefied Petroleum Gas (LPG) Installations*, be used to help develop a standard having a broader scope. The Committee on Liquefied Natural Gas was established for that purpose. The 1971 edition was the first edition of NFPA 59A developed under the broadened scope. Subsequent editions were adopted in 1972, 1975, 1979, 1985, 1990, 1994, 1996, and 2001.

The 2006 edition included revisions in compliance with the *Manual of Style for NFPA Technical Committee Documents*. Chapter 5 was revised to cover double and full containment LNG storage containers. Definitions of these types of containers were also added to the standard. Seismic design criteria for LNG containers were revised to correlate with the requirements of ASCE 7, *Minimum Design Loads for Buildings and Other Structures*. Chapter 11 was revised to add requirements for a contingency plan for potential LNG marine transfer incidents.

In the 2009 edition, additional vapor dispersion models were allowed where they are evaluated and approved by an independent body using the new Model Evaluation Protocol developed by the NFPA Research Foundation. The Design Spill table was revised to separate the design spill requirements for over-the-top fill/withdrawal containers, other containers, and process areas. Scope statements were added to each chapter, and the term *radiant heat flux* replaced *thermal radiation* throughout the document.

In the 2013 edition, Annex E, Performance-Based Alternative Standard for Plant Siting, was revised and relocated to the mandatory text as new Chapter 15, Performance (Risk Assessment) Based LNG Plant Siting. Use of the performance-based option required approval of the authority having jurisdiction. The performance-based option required analyzing the risks to persons and property in the area surrounding the proposed LNG plant based on risk mitigation techniques incorporated into the facility design. All of the minimum requirements of earlier chapters of NFPA 59A also had to be met. Chapter 15 provided several tables and figures to assist a facility designer in identifying those risks and determining if the risks are tolerable, as defined in Chapter 15.

The 2013 edition also incorporated several revisions to promote consistency between NFPA 59A and the Code of Federal Regulations, as well as some new terminology for tank systems. In addition, Chapters 7 and 14 were reorganized for easier use.

In the 2016 edition, several definitions were revised to establish a hierarchy of components, facilities, and plants. A new definition for *LNG facility* was added, and the definitions for *LNG plant* and *component* were revised to maintain consistency. Subsequent chapters were revised to correspond to the new definitions.

Additional changes were made to improve the fire safe design of outer concrete containers to avoid explosive spalling during a fire event. Revisions were made to requirements for inspections after repairs, detection of leaks, and post seismic events to provide greater confidence in the system's continued safety and integrity.

The 2016 edition also incorporated several revisions to enhance the use of Annex A. NFPA documents that had been listed in Annex A as informational references in previous editions were moved into Chapter 12 as enforceable code to address the design and installation requirements for fire protection systems. New and revised annex material was added to numerous sections to provide additional information, guidance, and clarification, as well as to point users to reference materials for further guidance.

The 2019 edition of the standard presents a reorganization of the requirements for plant siting and layout to facilitate better focus and implementation of these requirements. Elements of what had been in Chapter 5, Layout and Siting, are now presented separately as plant siting (Chapter 5), plant layout (Chapter 6), plant design (Chapter 12), impounding areas (Chapter 13), and mobile and temporary LNG facilities (Chapter 14). Annex C, Security, and Annex D, Training, are removed because their content in previous editions is now incorporated into the mandatory requirements of the standard. Also in this revision, the committee standardized the use of terminology.

Another notable change for NFPA 59A, 2019 edition, is the addition of a chapter to address small-scale LNG facilities. This chapter was built on what had been presented as requirements for ASME containers in this standard. However, the growth in the small- to mid-scale segment of the global LNG market prompted a re-evaluation of available storage technologies, including a single-wall ASME container with supplementary design and fabrication requirements. The committee developed Chapter 17, Requirements for Stationary Applications for Small Scale LNG Facilities, to establish the framework under which single-wall ASME containers used for LNG storage can be safely implemented at LNG facilities.

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This list represents the membership at the time the Committee was balloted on the final text of this edition. Since that time, changes in the membership may have occurred. A key to classifications is found at the back of the document.

NOTE: Membership on a committee shall not in and of itself constitute an endorsement of the Association or any document developed by the committee on which the member serves.

Committee Scope: This Committee shall have primary responsibility for documents on safety and related aspects in the liquefaction of natural gas and the transport, storage, vaporization, transfer, and use of liquefied natural gas.

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NFPA 59A

Standard for the

Production, Storage, and Handling of Liquefied Natural Gas (LNG)

2019 Edition

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NOTICE: An asterisk (*) following the number or letter designating a paragraph indicates that explanatory material on the paragraph can be found in Annex A.

A reference in brackets [ ] following a section or paragraph indicates material that has been extracted from another NFPA document. As an aid to the user, the complete title and edition of the source documents for extracts in mandatory sections of the document are given in Chapter 2 and those for extracts in informational sections are given in Annex C. Extracted text may be edited for consistency and style and may include the revision of internal paragraph references and other references as appropriate. Requests for interpretations or revisions of extracted text shall be sent to the technical committee responsible for the source document.

Information on referenced publications can be found in Chapter 2 and Annex C.

Chapter 1 Administration

1.1* Scope.

1.1.1 This standard shall apply to the following:

(1) The siting, design, construction, maintenance, and operation of facilities that produce, store, and handle liquefied natural gas (LNG)
(2) The training of personnel involved with LNG

1.1.2 This standard shall not apply to the following:

(1) Frozen ground containers
(2) Portable storage containers stored or used in buildings
(3) All LNG vehicular applications, including fueling of LNG vehicles

1.2 Purpose. The purpose of this standard is to provide minimum fire protection, safety, and related requirements for the siting, design, construction, security, operation, and maintenance of LNG plants.

1.3* Equivalency. Nothing in this standard is intended to prevent the use of systems, methods, or devices of equivalent or superior quality, strength, fire resistance, effectiveness, durability, and safety over those prescribed by this standard.

1.3.1 Technical documentation shall be submitted to the authority having jurisdiction to demonstrate equivalency.

N **1.3.2** The operator shall include any additional requirements to achieve equivalency in their procedures, as applicable.

1.3.3 The system, method, or device shall be approved for the intended purpose by the authority having jurisdiction.

1.4 Retroactivity. The provisions of this standard reflect a consensus of what is necessary to provide an acceptable degree of protection from the hazards addressed in this standard at the time the standard was issued.

1.4.1 Unless otherwise specified, the provisions of this standard shall not apply to facilities, equipment, structures, or installations that existed or were approved for construction or installation prior to the effective date of the standard. Where specified, the provisions of this standard shall be retroactive.

1.4.2 In those cases where the authority having jurisdiction determines that the existing situation presents an unacceptable degree of risk, the authority having jurisdiction shall be permitted to apply retroactively any portions of this standard deemed appropriate.

1.4.3 The retroactive requirements of this standard shall be permitted to be modified if their application clearly would be impractical in the judgment of the authority having jurisdiction, and only where it is clearly evident that a reasonable degree of safety is provided.

1.5* SI Units. SI units in this standard shall be based on IEEE/ASTM SI 10, *American National Standard for Use of the International System of Units (SI): The Modern Metric System.*

1.5.1 Alternate usage of U.S. customary units and SI units on a single project shall not be used to lessen clearance distances.

1.6 Pressure Measurement. All pressures expressed in this document are gauge pressures unless specifically noted otherwise.

1.7 Referenced Standards. Reference is made to both U.S. and Canadian standards, because this standard is prepared for use in both the United States and Canada, as well as in other countries.

1.7.1 Where this standard is adopted, the adoption shall include a statement of which U.S. or Canadian reference standards shall be used.

1.7.2 If no such statement is made, the user shall use either all available U.S. or all available Canadian reference standards.

1.7.3 If other reference standards are to be used, it shall be so stated.

Chapter 2 Referenced Publications

2.1* General. The documents or portions thereof listed in this chapter are referenced within this standard and shall be considered part of the requirements of this document.

2.2 NFPA Publications. National Fire Protection Association, 1 Batterymarch Park, Quincy, MA 02169-7471.

NFPA 4, *Standard for Integrated Fire Protection and Life Safety System Testing,* 2018 edition.

NFPA 10, *Standard for Portable Fire Extinguishers,* 2018 edition.

NFPA 11, *Standard for Low-, Medium-, and High-Expansion Foam,* 2016 edition.

NFPA 12, *Standard on Carbon Dioxide Extinguishing Systems,* 2018 edition.

NFPA 12A, *Standard on Halon 1301 Fire Extinguishing Systems,* 2018 edition.

NFPA 13, *Standard for the Installation of Sprinkler Systems,* 2019 edition.

NFPA 14, *Standard for the Installation of Standpipe and Hose Systems,* 2019 edition.

NFPA 15, *Standard for Water Spray Fixed Systems for Fire Protection,* 2017 edition.

NFPA 16, *Standard for the Installation of Foam-Water Sprinkler and Foam-Water Spray Systems,* 2019 edition.

NFPA 17, *Standard for Dry Chemical Extinguishing Systems,* 2017 edition.

NFPA 20, *Standard for the Installation of Stationary Pumps for Fire Protection,* 2019 edition.

NFPA 22, *Standard for Water Tanks for Private Fire Protection,* 2018 edition.

NFPA 24, *Standard for the Installation of Private Fire Service Mains and Their Appurtenances,* 2019 edition.

NFPA 25, *Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems,* 2017 edition.

NFPA 30, *Flammable and Combustible Liquids Code,* 2018 edition.

NFPA 37, *Standard for the Installation and Use of Stationary Combustion Engines and Gas Turbines,* 2018 edition.

NFPA 51B, *Standard for Fire Prevention During Welding, Cutting, and Other Hot Work,* 2019 edition.

NFPA 56, *Standard for Fire and Explosion Prevention During Cleaning and Purging of Flammable Gas Piping Systems,* 2017 edition.

ANSI Z223.1/NFPA 54, *National Fuel Gas Code,* 2018 edition.

NFPA 58, *Liquefied Petroleum Gas Code,* 2017 edition.

NFPA 59, *Utility LP-Gas Plant Code,* 2018 edition.

NFPA 68, *Standard on Explosion Protection by Deflagration Venting,* 2018 edition.

NFPA 69, *Standard on Explosion Prevention Systems,* 2019 edition.

NFPA 70®, National Electrical Code®, 2017 edition.

NFPA 72®, National Fire Alarm and Signaling Code, 2019 edition.

NFPA *101®, Life Safety Code®,* 2018 edition.

NFPA 110, *Standard for Emergency and Standby Power Systems,* 2019 edition.

NFPA 274, *Standard Test Method to Evaluate Fire Performance Characteristics of Pipe Insulation,* 2018 edition.

NFPA 385, *Standard for Tank Vehicles for Flammable and Combustible Liquids,* 2017 edition.

NFPA 496, *Standard for Purged and Pressurized Enclosures for Electrical Equipment,* 2017 edition.

NFPA 600, *Standard on Fire Brigades,* 2015 edition.

NFPA 750, *Standard on Water Mist Fire Protection Systems,* 2019 edition.

NFPA 1221, *Standard for the Installation, Maintenance, and Use of Emergency Services Communications Systems,* 2019 edition.

NFPA 1901, *Standard for Automotive Fire Apparatus,* 2016 edition.

NFPA 1961, *Standard on Fire Hose,* 2013 edition.

NFPA 1962, *Standard for the Care, Use, Inspection, Service Testing, and Replacement of Fire Hose, Couplings, Nozzles, and Fire Hose Appliances,* 2018 edition.

NFPA 1963, *Standard for Fire Hose Connections,* 2019 edition.

NFPA 2001, *Standard on Clean Agent Fire Extinguishing Systems,* 2018 edition.

NFPA 5000®, Building Construction and Safety Code®, 2018 edition.

2.3 Other Publications.

2.3.1 ACI Publications. American Concrete Institute, 38800 Country Club Dr., Farmington Hills, MI 48331.

ACI 304R, *Guide for Measuring, Mixing, Transportation and Placing of Concrete,* 2000, reapproved 2009.

ACI 318, *Building Code Requirements for Structural Concrete and Commentary,* 2014.

ACI 350, *Code Requirements for Environmental Engineering Concrete Structures,* 2006.

ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases,* 2011.

2.3.2 ALPEMA Publications. Brazed Aluminum Plate-Fin Heat Exchanger Manufacturer's Association, IHS (secretariat), 321 Inverness Drive South, Englewood, CO 80112.

The Standards of the Brazed Aluminum Plate-Fin Heat Exchanger Manufacturer's Association, 3rd Edition, 2012.

2.3.3 API Publications. American Petroleum Institute, 1220 L Street, NW, Washington, DC 20005-4070.

API 510, *Pressure Vessel Inspection Code: In-service Inspection, Rating, Repair, and Alteration, 10th edition,* 2014, with addendum 1 2017.

API RP 576, *Inspection of Pressure-Relieving Devices,* 4th edition, 2017.

API Spec 6D, *Specification for Pipeline and Piping Valves,* 24th edition, with errata 1-8 and addendums 1–2, 2014.

API Std 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks,* 12th edition, with addendum 1, 2014.

API Std 625, *Tank Systems for Refrigerated Liquefied Gas Storage,* with addendums 1–2, 2010.

API Std 650, *Welded Tanks for Oil Storage,* 12th edition, 2013, errata 1 2013, errata 2 2014, and addendum 1 2014, and addendum 2 2016.

API Std 2510, *Design and Construction of Liquefied Petroleum Gas (LPG) Installations,* 8th edition, 2001, reaffirmed 2011.

2.3.4 ASCE Publications. American Society of Civil Engineers, 1801 Alexander Bell Drive, Reston, VA 20191-4400.

ASCE 7, *Minimum Design Loads and Associated Criteria for Buildings and Other Structures,* 2016.

2.3.5 ASME Publications. American Society of Mechanical Engineers, Two Park Avenue, New York, NY 10016-5990.

ASME B31.1, *Power Plant Piping,* 2016.

ASME B31.3, *Process Piping,* 2016.

ASME B31.4, *Pipeline Transportation Systems for Liquids and Slurries,* 2016.

ASME B31.5, *Refrigeration Piping and Heat Transfer Components,* 2016.

ASME B31.8, *Gas Transmission and Distribution Piping Systems,* 2016.

Boiler and Pressure Vessel Code, 2017.

2.3.6 ASTM Publications. ASTM International, 100 Barr Harbor Drive, P.O. Box C700, West Conshohocken, PA 19428-2959.

ASTM E84, *Standard Test Method for Surface Burning Characteristics of Building Materials,* 2016.

ASTM E136, *Standard Test Method for Behavior of Materials in a Vertical Tube Furnace at 750°C,* 2016a.

ASTM E2652, *Standard Test Method for Behavior of Materials in a Tube Furnace with a Cone-shaped Airflow Stabilizer, at 750°C,* 2016.

2.3.7 CGA Publications. Compressed Gas Association, 14501 George Carter Way, Suite 103, Chantilly, VA 20151-1788.

CGA 341, *Standard for Insulated Cargo Tank Specification for Cryogenic Liquids,* 2007, reaffirmed 2011.

CGA S-1.3, *Pressure Relief Device Standards — Part 3 — Stationary Storage Containers for Compressed Gases,* 2008.

2.3.8 CSA Publications. CSA Group, 178 Rexdale Blvd. Toronto, ON M9W 1R3, Canada.

CSA B51, *Boiler, Pressure Vessel and Pressure Piping Code,* 2014.

CSA C22.1, *Canadian Electrical Code,* 2015.

2.3.9 IEEE Publications. IEEE, 3 Park Avenue, 17th Floor, New York, NY 10016-5997.

IEEE/ASTM SI 10, *American National Standard for Use of the International System of Units (SI): The Modern Metric System,* 2010.

N **2.3.10 ISA Publications.** The International Society of Automation, 67 T.W. Alexander Drive, PO Box 12277, Research Triangle Park, NC 27709.

ISA 12.27.01, *Requirements for Process Sealing Between Electrical Systems and Flammable or Combustible Process Fluids,* 2011.

2.3.11 NACE Publications. NACE International, 15835 Park Ten Place, Houston, TX 77084-4906.

NACE SP0169, *Control of External Corrosion of Underground or Submerged Metallic Piping Systems,* 2013.

NACE SP0198, *Control of Corrosion Under Insulation and Fireproofing Materials — A Systems Approach,* 2016.

2.3.12 UL Publications. Underwriters Laboratories, Inc., 333 Pfingsten Road, Northbrook, IL 60062–2096.

ANSI/UL 723, *Standard for Test for Surface Burning Characteristics of Building Materials,* 2008, revised 2013.

2.3.13 Other Publications.

ANSI/NB-23, *National Board Inspection Code, Part 2, Inspection,* Section 2, The National Board of Boiler and Pressure Vessel Inspectors, Columbus, OH, 2017.

ASNT SNT-TC-1A, *Personnel Qualification and Certification in Nondestructive Testing,* 2016.

BS EN 14620, *Design and manufacture of site built, vertical, cylindrical, flat-bottomed, steel tanks for the storage of refrigerated, liquefied gases with operating temperatures between 0°C and –165°C,* Parts 1–5, 2006.

CEB Bulletin 187, *Concrete Structures Under Impact and Impulsive Loading — Synthesis Report,* International Federation for Structural Concrete, Switzerland, 1988.

Merriam-Webster's Collegiate Dictionary, 11th edition, Merriam-Webster, Inc., Springfield, MA, 2003.

2.4 References for Extracts in Mandatory Sections.

NFPA 52, *Vehicular Gaseous Fuel Systems Code,* 2019 edition.
NFPA 54, *National Fuel Gas Code,* 2018 edition.
NFPA *101*®, *Life Safety Code*®, 2018 edition.

Chapter 3 Definitions

3.1 General. The definitions contained in this chapter shall apply to the terms used in this standard. Where terms are not defined in this chapter or within another chapter, they shall be defined using their ordinarily accepted meanings within the context in which they are used. *Merriam-Webster's Collegiate Dictionary,* 11th edition, shall be the source for the ordinarily accepted meaning.

3.2 NFPA Official Definitions.

3.2.1* Approved. Acceptable to the authority having jurisdiction.

3.2.2* Authority Having Jurisdiction (AHJ). An organization, office, or individual responsible for enforcing the requirements of a code or standard, or for approving equipment, materials, an installation, or a procedure.

3.2.3 Shall. Indicates a mandatory requirement.

3.2.4 Should. Indicates a recommendation or that which is advised but not required.

3.2.5 Standard. An NFPA Standard, the main text of which contains only mandatory provisions using the word "shall" to indicate requirements and that is in a form generally suitable for mandatory reference by another standard or code or for adoption into law. Nonmandatory provisions are not to be considered a part of the requirements of a standard and shall be located in an appendix, annex, footnote, informational note, or other means as permitted in the NFPA Manuals of Style. When used in a generic sense, such as in the phrase "standards development process" or "standards development activities," the term "standards" includes all NFPA Standards, including Codes, Standards, Recommended Practices, and Guides.

3.3 General Definitions.

N **3.3.1 ASME Container.** See 3.3.5.2, Pressure Vessel.

3.3.2 Bunkering. The loading of a ship's bunker or tank with fuel for use in connection with propulsion or auxiliary equipment.

3.3.3 Cargo Tank Vehicle. A tank truck or trailer designed to transport liquid cargo.

3.3.4 Component. A part or a system of parts that functions as a unit in an LNG facility and could include, but is not limited to, piping, processing equipment, containers, control devices, impounding systems, electrical systems, security devices, fire control equipment, and communication equipment.

3.3.5* Container. A vessel, tank, portable tank, or cargo tank used for or capable of holding, storing, or transporting liquid or gas.

3.3.5.1 ***Frozen Ground Container.*** A container in which the maximum liquid level is below the normal surrounding grade, that is constructed essentially of natural materials, such as earth and rock, that is dependent on the freezing of water-saturated earth materials, and that has appropriate methods for maintaining its tightness or that is impervious by nature.

N **3.3.5.2** ***Pressure Vessel.*** A container designed and fabricated in accordance with the ASME *Boiler and Pressure Vessel Code*, Section VIII, Division 1 or Division 2, or with CSA B51, *Boiler, Pressure Vessel, and Pressure Piping Code*.

3.3.5.3 ***Prestressed Concrete Container.*** A concrete container where the concrete is placed into compression by internal or external tendons or by external wire wrapping.

Δ **3.3.5.4** ***Tank System.*** Low-pressure (less than 15 psi) equipment designed for storing liquefied natural gas or other hazardous liquids, consisting of one or more containers, together with various accessories, appurtenances, and insulation.

3.3.5.4.1* ***Double-Containment Tank System.*** A single-containment tank system surrounded by and within 20 ft (6 m) of a self-standing containment wall (i.e., secondary container) that is open to the atmosphere and designed to contain LNG in the event of a spill from the primary or inner container.

Δ **3.3.5.4.2*** ***Full-Containment Tank System.*** A tank system in which the self-standing inner (i.e., primary) container is surrounded by a separate self-standing secondary container designed to contain LNG in the event of a spill from the inner container, and the secondary container is enclosed by a steel or concrete roof designed such that excess vapor caused by a spill of LNG from the primary container will discharge through the relief valves.

Δ **3.3.5.4.3*** ***Membrane-Containment Tank System.*** A tank system consisting of a thin metal liquid barrier and load-bearing thermal insulation supported by a self-standing outer container jointly forming an integrated composite tank system designed to contain liquid and vapor during tank operation as well as LNG in the event of leakage from the liquid barrier, and where the vapor-containing roof of the outer container is either steel or concrete configured such that the excess vapor caused by a spill of LNG from the liquid barrier will discharge through the relief valves.

Δ **3.3.5.4.4*** ***Single-Containment Tank System.*** A tank system in which the self-standing inner (i.e., primary) container is designed to contain LNG and is surrounded by a separate container that is not designed to contain LNG.

3.3.6 Controllable Emergency. An emergency where operator action can minimize harm to people or property.

3.3.7 Design Pressure. The pressure used in the design of equipment, a container, or a pressure vessel for the purpose of determining the minimum allowable thickness or physical characteristics of its parts.

3.3.8 Dike. A structure used to establish an impounding area or containment. [**52,** 2019]

3.3.9* Engineering Design. Documentation governing the specification and design of components and systems within an LNG facility.

N **3.3.10 Event.** The combination of successive outcomes of LNG or hazardous material releases and their subsequent hazard to persons exposed.

3.3.11 Fail-safe. A design feature that provides for the maintenance of safe operating conditions in the event of a malfunction of control devices or an interruption of an energy source.

3.3.12* Fire Protection. Fire prevention, fire detection, and fire suppression.

3.3.13 Fired Equipment. Any equipment in which the combustion of fuels takes place.

3.3.14 Flame Spread Index. A number obtained according to ASTM E84, *Standard Test Method for Surface Burning Characteristics of Building Materials*, or ANSI/UL 723, *Standard for Test for Surface Burning Characteristics of Building Materials*.

3.3.15 Hazardous Fluid. A liquid or gas that is flammable, toxic, or corrosive.

3.3.16 Impounding Area. An area defined through the use of curbing, spill conveyances, dikes, the site topography, or other means for containing any accidental spill of LNG or other hazardous liquid.

N **3.3.17 Individual Risk.** The frequency, expressed in number of realizations per year, at which an individual, with continuous potential exposure, can be expected to sustain irreversible harm and fatal injury.

3.3.18 Liquefied Natural Gas (LNG). A fluid in the cryogenic liquid state that is composed predominantly of methane and that can contain minor quantities of ethane, propane, nitrogen, and other components normally found in natural gas.

3.3.19* LNG Facility. A collection of components used to produce, store, vaporize, transfer, or handle LNG.

3.3.20 LNG Plant. An LNG facility or collection of LNG facilities functioning as a unit.

N **3.3.21 Marine Vessel.** A water craft or other artificial contrivance used as a means of transportation in or on the water.

3.3.22 Maximum Allowable Working Pressure (MAWP). The maximum gauge pressure permissible at the top of completed equipment, a container, or a vessel in its operating position for a design temperature.

3.3.23 Model. A mathematical characterization intended to predict a physical phenomenon.

Δ **3.3.24 Noncombustible Material.** *See Section 4.10.* [***101,*** 2018].

3.3.25 Out-of-Service. The deactivation of a component for any purpose, including repairs or inspections.

3.3.26 Overfilling. Filling to a level above the maximum design liquid level.

3.3.27 Pipe Insulation Assembly. The set of materials used for insulation of pipes, including the insulation, outer jacket, vapor barrier and lap-seal adhesives.

3.3.28 Pressure Relief Device. A device designed to open to prevent a rise of internal pressure in excess of a specified value due to emergency or abnormal conditions.

N **3.3.29 Societal Risk.** The cumulative risk exposure by all persons sustaining irreversible harm and fatal injury from an event in the LNG plant.

3.3.30 Sources of Ignition. Appliances or equipment that, because of their intended modes of use or operation, are capable of providing sufficient thermal energy to ignite flammable gas–air mixtures. [**54,** 2018]

N **3.3.31 Stationary System.** All equipment associated with the system is fixed from movement and does not incorporate "make or break" connections between each associated piece of equipment, except for those connections used for transfer of fluids into or from the system that are manned by trained personnel during those transfers.

N **3.3.32 Storage Tank.** A low-pressure container designed for an internal gas pressure of 15 psi or less, in accordance with API Std 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks,* or API Std 650, *Welded Tanks for Oil Storage.*

N **3.3.33 Tank.** See 3.3.32, Storage Tank.

N **3.3.34 Tank Car.** A type of railroad car, tank wagon, or rolling stock designed to transport liquid and gaseous commodities.

3.3.35 Tank Vehicle. See 3.3.3, Cargo Tank Vehicle.

3.3.36* Transfer Area. The portion of an LNG plant where LNG or other hazardous fluids are introduced into or removed from the plant and where necessary connections are connected or disconnected routinely.

3.3.37 Transition Joint. A connector fabricated of two or more metals used to effectively join piping sections of two different materials that are not amenable to the usual welding or joining techniques.

3.3.38* Vacuum-Jacketed. A method of construction that incorporates an outer shell designed to maintain a vacuum in the annular space between the inner container or piping and outer shell.

3.3.39* Vaporizer. Equipment designed to introduce thermal energy in a controlled manner for changing a liquid to a vapor or gaseous state.

3.3.39.1 ***Ambient Vaporizer.*** A vaporizer that derives its heat from naturally occurring heat sources, such as the atmosphere, seawater, or geothermal waters.

3.3.39.2 ***Heated Vaporizer.*** A vaporizer that derives heat for vaporization from the combustion of fuel, electric power, or waste heat, such as from boilers or internal combustion engines. [**52,** 2019]

3.3.39.2.1 ***Integral Heated Vaporizer.*** A vaporizer, including submerged combustion vaporizers, in which the heat source is integral to the actual vaporizing exchanger. [**52,** 2019]

3.3.39.2.2 ***Remote Heated Vaporizer.*** A heated vaporizer in which the primary heat source is separated from the actual vaporizing exchanger, and an intermediate fluid (e.g., water, steam, isopentane, glycol) is used as the heat transport medium.

3.3.39.3 ***Process Vaporizer.*** A vaporizer that derives its heat from another thermodynamic or chemical process to utilize the refrigeration of the LNG.

N **3.3.40 Vessel.** See 3.3.5.2, Pressure Vessel.

3.3.41 Water Capacity. The amount of water at 60°F (16°C) required to fill a container. [**52,** 2019]

Chapter 4 General Requirements

4.1 Scope. This chapter covers the general requirements for facilities covered under this standard.

N **4.2* Designer and Fabricator Competence.**

N **4.2.1*** Soil and general investigations shall be made to determine the adequacy of the intended site for the facility.

N **4.2.2** Designers, fabricators, constructors, installers, inspectors, and those performing testing shall be competent and qualified by training or experience and accomplishments in performing their assigned functions in their respective fields.

N **4.2.2.1** Each operator shall periodically determine whether construction, installation, and testing inspectors are satisfactorily performing their assigned functions.

N **4.2.3** Supervision shall be provided for the fabrication, construction, and acceptance tests of facility components to verify that the facilities are structurally sound and otherwise in compliance with this standard.

N **4.3* Soil Protection for Cryogenic Equipment.** LNG containers *(see 8.3.4)*, cold boxes, piping and pipe supports, and other cryogenic apparatus shall be designed and constructed to prevent damage to these structures and equipment due to freezing or frost heaving in the soil, or means shall be provided to prevent damaging forces from developing.

N **4.4 Falling Ice and Snow.** Measures shall be taken to protect personnel and equipment from falling ice or snow that has accumulated on high structures.

N **4.5 Concrete Design and Materials.**

N **4.5.1** Concrete structures that are normally or periodically in contact with LNG, including the foundations of cryogenic containers, shall be designed to withstand the design load, applicable environmental loadings, and anticipated temperature effects.

N **4.5.1.1** The material and design of the structures other than LNG containers shall be in accordance with the provisions of ACI 318, *Building Code Requirements for Structural Concrete and Commentary.*

N **4.5.2** Structural concrete for pipe supports shall comply with Section 10.6.

N **4.5.3 Other Concrete Structures.**

N **4.5.3.1** All other concrete structures shall be investigated for the effects of potential contact with LNG.

N **4.5.3.2** If failure of these structures would create a hazardous condition or worsen an existing emergency condition by exposure to LNG, the structures shall be protected to minimize the effects of such exposure, or they shall comply with 8.4.13.2.

N **4.5.4*** Nonstructural concrete for incidental nonstructural uses, such as slope protection, impounding area paving, and other nonstructural slabs-on-grade, shall conform to ACI 304R, *Guide for Measuring, Mixing, Transportation and Placing of Concrete.*

N **4.5.5 Minimum Reinforcement.**

N **4.5.5.1** Reinforcement for concrete structures designed for LNG containment or cold vapor containment, other than those in 4.5.1; or for concrete structures covered in 4.5.2 and 4.5.3 shall be a minimum of 0.5 percent of the cross-sectional area of concrete for crack control in accordance with Appendix G of ACI 350, *Code Requirements for Environmental Engineering Concrete Structures.*

N **4.5.5.2** Minimum reinforcement for concrete for incidental nonstructural uses covered in 4.5.4 shall be in accordance with the shrinkage and temperature reinforcement provisions of ACI 318, *Building Code Requirements for Structural Concrete and Commentary.*

N **4.5.6** Concrete that is not constantly exposed to LNG and that has been subjected to sudden and unexpected exposure to LNG shall be inspected, and repaired if necessary, as soon as is practical after it has returned to ambient temperature.

4.6 Engineering Review of Changes.

Δ **4.6.1** Components shall not be constructed or significantly altered in accordance with 4.6.2 until a qualified person from each of the following disciplines, as applicable, reviews the design drawings and specifications and determines that the design will not impair the safety or reliability of the component or any associated components:

(1) Process engineering
(2) Mechanical engineering
(3) Geotechnical and civil engineering
(4) Electrical and instrumentation engineering
(5) Materials and corrosion engineering
(6) Fire protection and safety engineering

4.6.2 The repair, replacement, or significant alteration of components shall be reviewed only if the action to be taken involves or is due to one of the following:

(1) A change in the original components specified
(2) A failure caused by corrosion
(3) A failure resulting in a loss of containment
(4) An inspection that reveals a significant deterioration of the component

4.7 Control Center.

Δ **4.7.1** Each LNG plant, other than those complying with Chapter 17, shall have a control center from which operations and warning devices are monitored.

4.7.2 A control center shall have the following capabilities and characteristics:

(1) It shall be located apart from or be protected from other components so that it is operational during a controllable emergency.
(2) Each remotely actuated control system and each automatic shutdown control system required by this standard shall be operable from the control center responsible for monitoring as required by 18.6.1.
(3) It shall have personnel in attendance while process systems (e.g., vaporization, liquefaction, transfers of LNG) under its control are in operation, with exceptions described in Section 18.6 during any operations monitoring or when another manned control center has control or the facility has an automatic emergency shutdown system.
(4) Onsite control centers when unattended during operations monitoring as described in 18.6.1.1 shall have the capability of initiating an audible or visual signal, or both, to alert operating personnel performing operations monitoring.
(5) If more than one is located at an LNG plant, each control center shall have more than one means of communication with every other center.
(6) It shall have a means of communicating a warning of hazardous conditions to other locations within the plant frequented by personnel.

4.8 Sources of Power.

Δ **4.8.1** Electrical control systems, means of communication, emergency lighting, fire-fighting systems, and security-related systems (including lighting) shall have at least two sources of power that function so that failure of one source does not affect the capability of the other source.

4.8.2 Where auxiliary generators are used as a second source of electrical power, the following shall apply:

(1) They shall be located apart from or be protected from components so that they are not unusable during a controllable emergency.
(2) The fuel supply shall be protected from hazards.
(3) Where installed, emergency power systems and standby power systems shall be installed in accordance with NFPA 110, and the emergency power supply system level and class shall be determined by an engineering review.

4.9 Records.

4.9.1 Each plant shall have a record of materials of construction for components, buildings, foundations, and support systems used for containment of LNG or other hazardous liquids.

4.9.2 The records shall verify that the material properties meet the requirements of this standard.

4.9.3 The records shall be maintained for the life of the components, buildings, foundations, and support systems.

4.10* Noncombustible Material. A material that complies with any of the following shall be considered a noncombustible material:

(1)* In the form in which it is used and under the conditions anticipated, it will not ignite, burn, support combustion, or release flammable vapors when subjected to fire or heat.
(2) It passes the noncombustible criterion of ASTM E136, *Standard Test Method for Behavior of Materials in a Vertical Tube Furnace at 750°C.*
(3) It passes the noncombustible criterion of ASTM E136 when tested in accordance with the test method and procedure in ASTM E2652, *Standard Test Method for Behavior of Materials in a Tube Furnace with a Cone-shaped Airflow Stabilizer, at 750°C.*

4.11 Ignition Source Control.

4.11.1 Smoking shall be permitted only in designated and sign-posted areas.

4.11.2 Welding, cutting, and hot work shall be conducted in accordance with the provisions of NFPA 51B and shall include continuous flammable gas monitoring in areas not covered by other hazard detection systems.

4.11.3 Portable electric tools and extension lights capable of igniting LNG or other flammable fluids shall not be permitted within classified areas except where the area has been identified as free of flammable fluids.

4.11.4 Vehicles and other mobile equipment that constitute potential ignition sources shall be prohibited within hazardous (electrically classified) locations, except where designated by the operator and at loading or unloading at facilities specifically designed for the purpose.

Chapter 5 Plant Siting

Δ **5.1 Scope.** This chapter presents the criteria for plant siting.

5.2* Plant Site Provisions.

5.2.1 A written plant and site evaluation shall identify and analyze potential incidents that have a bearing on the safety of plant personnel and the surrounding public. The plant and site evaluation shall also identify safety and security measures incorporated in the design and operation of the plant considering the following, as applicable:

(1) Process hazard analysis
(2) Transportation activities that might impact the proposed plant
(3) Adjacent facility hazards
(4) Meteorological and geological conditions
(5) Security threat and vulnerability analysis

N **5.2.2** An analysis shall be performed and documented to demonstrate the consequences associated with potential incidents from identified hazards in accordance with Chapter 5 or Chapter 19.

Δ **5.2.3** All-weather accessibility to the plant for personnel safety and fire protection shall be provided.

5.3 Site Provisions for Spill and Leak Control.

5.3.1 General.

Δ **5.3.1.1** Provisions shall be made to minimize the potential of discharge of LNG or other hazardous liquids at containers, piping, and other equipment such that a discharge from any of these does not endanger adjoining property, occupied buildings, or important process equipment and structures or reach waterways.

N **5.3.1.2** LNG containers and hazardous liquid storage tanks shall be provided with one of the following methods to contain any release:

(1) An impounding area surrounding the container(s) that is formed by a natural barrier, dike, impounding wall, or combination thereof complying with Chapter 13 and Chapter 6
(2) An impounding area formed by a natural barrier, dike, excavation, impounding wall, or combination thereof complying with Chapter 13 and Chapter 6, plus a natural or man-made drainage system surrounding the container(s) that complies with Chapter 13 and Chapter 6
(3) Where the container is constructed below or partially below the surrounding grade, an impounding area formed by excavation complying with Chapter 13 and Chapter 6
(4) Secondary containment as required for double-, full-, or membrane-containment tank systems complying with Chapter 13 and Chapter 6.

5.3.1.3 Where there is a possibility for hazardous liquid releases to accumulate on the ground and endanger adjoining property, occupied buildings, important process equipment and structures, or reach waterways, the following areas shall be graded, drained, or provided with impoundment:

(1) Process areas
(2) Vaporization areas
(3) Liquefaction areas
(4) Transfer areas for LNG, flammable refrigerants, and flammable liquids
(5) Areas immediately surrounding flammable refrigerant and flammable liquid storage tanks

N **5.3.1.4** Secondary containment systems designed in accordance with 10.13.3.2 shall be permitted to serve as an impounding area.

5.3.1.5 If impounding areas also are required in order to comply with 5.3.1.7, such areas shall be in accordance with Chapter 13 and Chapter 6.

Δ **5.3.1.6** The provisions of 5.3.1.7, 5.3.1.1, 5.3.1.2 and 5.3.1.3 that apply to adjoining property or waterways shall be permitted to be waived or altered at the discretion of the authority having jurisdiction where the change does not constitute a distinct hazard to life or property or conflict with applicable federal, state, and local (national, provincial, and local) regulations.

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5.3.1.7 Site preparation shall include provisions for retention of spilled LNG and other hazardous liquids where liquids might accumulate on the ground within the limits of plant property and for surface water drainage.

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N 5.3.2 Hazard Analysis.

N 5.3.2.1 The following types of hazards and calculations of the extent of hazards shall be evaluated as follows, with the exception of feed gas and send out gas lines:

(1) Distance to limit concentration levels arising from flammable gas or vapor dispersion
(2) Distance to limit concentration levels arising from toxic gas or vapor dispersion
(3) Distance to limit overpressure levels arising from explosions
(4) Distance to limit heat flux or heat dosage levels arising from pool fires
(5) Distance to limit heat flux or heat dosage levels arising from jet fires
(6) Distance to limit heat flux or heat dosage levels arising from fireballs

N 5.3.2.2* The use of active mitigation techniques in the calculation of hazard distances and cascading potential shall be subject to the approval of the AHJ.

N 5.3.2.3* Each LNG plant shall define a set of design spills in accordance with Table 5.3.2.3 and the design spill duration period set in 5.3.2.4.

N 5.3.2.3.1 The bounding hazard distances associated with design spills as defined in Table 5.3.2.3 shall be documented.

N 5.3.2.3.2 Each portion of the plant that could produce a distinct hazard distance shall be represented.

N 5.3.2.4 Design Spill Duration. The design spill duration shall be the shortest among the following:

(1) The demonstrated and approved shutdown time based on automated surveillance and detection that does not require human intervention, which can be verified in detailed design and operation.
(2) Ten minutes for approved surveillance and detection that requires human intervention for shutdown
(3) The time needed to empty the available system inventory if no approved surveillance and detection is present

N 5.3.2.5 Source term models shall have a creditable scientific basis and shall not ignore phenomena that can influence vapor evolution rate as follows:

(1) During discharge from piping or equipment and associated flashing and jetting effects
(2) During conveyance of liquid to an impoundment and subsequent vaporization
(3) Due to liquid flow into and retention within an impoundment

Table 5.3.2.3 Design Spill

Design Spill Source	Design Spill Criteria	Design Spill Rate
Storage Containers		
Containers with penetrations below the liquid level without internal shutoff valves in accordance with 10.4.2.5	A liquid spill through an assumed opening at, and equal in area to, that penetration below the liquid level resulting in the largest flow from an initially full container If more than one container in the impounding area, use the container with the largest flow	Use the following formula: $q = \frac{4}{3} d^2 \sqrt{h}$ For SI units, use the following formula: $q = \frac{1.06}{10{,}000} d^2 \sqrt{h}$ until the differential head acting on the opening is 0.
Containers with penetrations below the liquid level with internal shutoff valves in accordance with 10.4.2.5	The liquid spill through an assumed opening at, and equal in area to, that penetration below the liquid level that could result in the largest flow from an initially full container	Use the following formula: $q = \frac{4}{3} d^2 \sqrt{h}$ For SI units, use the following formula: $q = \frac{1.06}{10{,}000} d^2 \sqrt{h}$
Piping and Other Equipment		
Process systems or transfer areas involving hazardous fluids	For piping, arms, and hoses that are: (1) Greater than or equal to 6 in. diameter, a hole size of 2 in. diameter is applied at any location along the piping segment (2) Less than 6 in. diameter, a full-bore rupture is applied at any location along the piping segment	The calculated flow* based on the following: (1) The physical and thermodynamic properties of the released fluid (2) The physical characteristics of the process or containment system
Pipe-in-pipe systems designed in accordance with Section 10.13 to serve as secondary containment	No design spill — setback in accordance with Table 6.3.1 based on isolatable volume within the pipe-in-pipe system	

Note: q = flow rate [ft^3/min (m^3/min)] of liquid; d = diameter [in. (mm)] of penetration below the liquid level; h = height [ft (m)] of liquid above penetration in the container when the container is full, plus the equivalent head for the vapor pressure above the liquid.
*See A.5.3.2.2.

N **5.3.2.6* Weather and Modeling Parameters.** Models employed in 5.3.2.9 through 5.3.2.12 shall be approved and shall have available documentation that demonstrates the following:

(1) The scientific assessment of the physical phenomena observed in experimental data applicable to the physical situation
(2) Verification processes for the details of the physics, analysis, and execution process
(3) Validation with experimental, including available field-scale, data applicable to the physical situation

N **5.3.2.7** Models employed in 5.3.2.8 and 5.3.2.9 shall incorporate the following:

(1) In calculating hazard distances, the combination of wind speed adjusted to or at a reference height of 33 ft (10 m), ambient temperature, atmospheric stability, and relative humidity that produces the maximum distances shall be used except for conditions that occur less than 10 percent of the time based on recorded data for the area.
(2) As an alternative, the maximum distances shall be permitted to be calculated using a wind speed of 4.5 mph (2 m/sec) at a 33 ft (10 m) measurement height, atmospheric stability class F, average ambient temperature for the region, and 50 percent relative humidity.
(3) All wind directions shall be considered.
(4) The surface roughness that is representative of the area upwind of the site shall be used.
(5) The effects of passive and approved active mitigation techniques shall be permitted to be incorporated into the modeling.

N **5.3.2.8** Jet fire and pool fire models employed in 5.3.2.12 shall incorporate the following:

(1) In calculating hazard distances, the combination of wind speed adjusted to or at a reference height of 33 ft (10 m), ambient temperature, and relative humidity that produces the maximum distances shall be used except for conditions that occur less than 10 percent of the time based on recorded data for the area.
(2) As an alternative, the maximum distances shall be permitted to be calculated using weather parameters of 20 mph (9 m/sec) winds measured at a reference height of 33 ft (10 m), average ambient temperature for the area, and 50 percent relative humidity shall be applied as default conditions.
(3) All wind directions shall be considered.
(4) The effects of passive and approved active mitigation techniques shall be incorporated into the modeling.

N **5.3.2.9* Flammable Gas or Vapor Dispersion.** The siting of the plant shall be such that, in the event of an LNG or other flammable or combustible fluid release as specified in 5.3.2.3, a predicted concentration to the lower flammability limit (LFL) does not extend beyond the property line that can be built upon.

N **5.3.2.10 Toxic Gas or Vapor Dispersion.** The siting of the plant shall be such that, in the event of a toxic fluid release as specified in 5.3.2.3, a predicted maximum concentration from a release does not exceed the limits listed in Table 5.3.2.10.

N **5.3.2.11 Vapor Cloud Explosions.** The siting of the plant shall be such that, in the event of the ignition of a flammable cloud in a confined or congested area based on a design spill as specified in 5.3.2.3, a maximum overpressure from an explosion does not exceed the limits listed in Table 5.3.2.11.

N **5.3.2.12 Fires.** The siting of the plant shall be such that, in the event of an LNG or other flammable or combustible fluid release as specified in 5.3.2.3, a maximum radiant heat flux from a fire shall not exceed the limits listed in Table 5.3.2.12.

N **5.3.2.12.1** For fireballs, the exposure extent shall be calculated using a dose equivalent to 1,600 Btu/hr/ft^2 and 40-second exposure time (7.5 × 105 (Btu/hr/ft^2)$^{4/3}$s).

N **5.3.2.13*** The hazard footprint calculated in 5.3.2.9 through 5.3.2.12 shall account for the uncertainty factors determined in 5.3.2.7 and 5.3.2.8.

N **5.3.2.14 Cascading Damage.** Equipment shall be located or protected so that impacts from 5.3.2.11 and 5.3.2.12 shall not cause major structural damage to any LNG storage container, LNG marine carrier, refrigerant storage vessel, buildings, or equipment required for the safe shutdown and control of the hazard.

Table 5.3.2.10 Toxic Concentration Limits to Property Lines and Occupancies

Toxic Concentration		
Acute Exposure Guideline Levels (AEGL)	**Description**	**Exposure**
AEGL-1	Toxic concentration at which notable discomfort, irritation, or certain asymptomatic non-sensory effects; however, the effects are not disabling and are transient and reversible upon cessation of exposure	The area that will be potentially notified for toxic clouds in the emergency response plan required in Section 18.4
AEGL-2	Toxic concentration at which irreversible or other serious, long-lasting adverse health effects or an impaired ability to escape	The nearest point on the building or structure outside the owner's property line that is in existence at the time of plant siting and used for assembly, educational, health care, detention and correction, or residential occupancies for a toxic cloud
AEGL-3	Toxic concentration at which life-threatening health effects or death can occur	A property line that can be built upon for dispersion of a design spill resulting in a toxic cloud

Table 5.3.2.11 Overpressure Limits to Property Lines and Occupancies

Overpressure		
Overpressure	**Description**	**Exposure**
1 psi	Overpressure at which persons can be indirectly affected	The nearest point on the building or structure outside the owner's property line that is in existence at the time of plant siting and used for assembly, educational, health care, detention and correction, or residential occupancies for a vapor cloud explosion
3 psi	Overpressure at which persons can be directly affected	A property line that can be built upon for ignition of a design spill resulting in a vapor cloud explosion

Table 5.3.2.12 Radiant Heat Flux Limits to Property Lines and Occupancies

Radiant Heat Flux		
Btu/hr/ft^2	**W/m^2**	**Exposure**
1,600	5,000	A property line at ground level that can be built upon for ignition of a design spill resulting in a fireball[a], jet fire, or pool fire
1,600	5,000	The nearest point located outside the owner's property line at ground level that, at the time of plant siting, is used for outdoor assembly by groups of 50 or more persons for a pool fire in an LNG storage tank impounding area[b]
3,000	9,000	The nearest point on the building or structure outside the owner's property line that is in existence at the time of plant siting and used for assembly, educational, health care, detention and correction, or residential occupancies for a pool fire in an LNG storage tank impounding area[b,c]
10,000	30,000	A property line at ground level that can be built upon for a pool fire over an LNG storage tank impounding area[b]

Notes:
[a]See 5.3.2.12.1.
[b]The requirements for LNG storage tank impounding areas are located in Chapter 13.
[c]See NFPA *101* or *NFPA 5000* for definitions of occupancies.

N Chapter 6 Plant Layout

N 6.1 Scope. This chapter presents the criteria for plant and equipment layout.

N 6.2 General Layout.

N 6.2.1* The layout between components and facilities shall allow for the necessary access to operate and maintain the plant.

N 6.2.2* The layout between components and facilities shall consider prevailing wind direction and ignition sources.

N 6.2.3 If cameras are required for security or operational purposes by 16.8.1.1 or Section 18.6, respectively, the camera layout shall allow for operators and security personnel to clearly monitor the facilities.

N 6.2.4 The layout between components and facilities shall allow for the access and egress by personnel and emergency responders.

N 6.3 Container Spacing.

N 6.3.1 The minimum separation distance associated with any type of LNG container or tanks containing flammable refrigerants shall be in accordance with Table 6.3.1 or with the approval of the authority having jurisdiction at a shorter distance from buildings or walls constructed of concrete or masonry but at least 10 ft (3.0 m) from any building openings.

N 6.3.2 Double-, full-, and membrane-containment tank systems shall be separated from a fire in an adjacent single- or double-containment impoundment area such that a fire within the adjacent impoundment or from a design spill will not cause loss of containment. This shall be accomplished by ensuring that the storage container roof, walls, insulation, or its impoundment structure do not reach temperatures at which mechanical properties of the container roof, wall, insulation, or its impoundment are reduced to levels where the LNG tank system, roof, insulation, or impoundment will collapse or burst or product liquid or uncontrolled vapor release will occur. The application of engineering analyses shall be used to determine this by including the following conditions in the analyses:

(1) The analyses shall be performed for a fire involving the complete loss of containment of the primary liquid container to an impoundment area that complies with the requirements of Section 13.1.
(2) The analyses shall account for the following:
    (a) The duration of the fire, the radiant heat emission characteristics of the fire, and the physical attributes of the fire under the anticipated atmospheric conditions
    (b) Atmospheric conditions that produce the maximum separation distances — except for conditions that occur less than 10 percent of the time based on recorded data for the area and using an LNG fire model in accordance with 5.3.2
    (c) Active or passive systems to reduce thermal heat flux incident on the surface or to limit the surface temperature
    (d) The materials, design, and methods of construction of the target LNG tank being analyzed

N 6.3.2.1 The outer concrete container shall be designed for the external fire in accordance with ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases*, unless fire protection measures are provided. The outer tank thermal analysis shall be performed to determine temperature distribution for the heat flux and duration of exposure as specified by the facility designer.

N 6.3.2.1.1 The applicable load components and the ultimate state load factors for the fire load combinations shall be in accordance with ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases*, Table 7.3. For membrane tank systems, an additional liquid pressure load in accordance with ACI 376, Table 7.2, shall be included. For all tanks, assessment during fire shall assume that design positive internal gas pressure applies.

N Table 6.3.1 Distances from Containers and Exposures

Container Water Capacity		Minimum Distance from Edge of Impoundment or Container Drainage System to Property Lines That Can Be Built Upon		Minimum Distance Between Storage Containers	
gal	m^3	ft	m	ft	m
<125*	<0.5	0	0	0	0
125–500	≥0.5–1.9	10	3	3	1
501–2,000	≥1.9–7.6	15	4.6	5	1.5
2,001–18,000	≥7.6–63	25	7.6	5	1.5
18,001–30,000	≥63–114	50	15	5	1.5
30,001–70,000	≥114–265	75	23		
>70,000	>265	0.7 times the container diameter but not less than 100 ft (30 m)		¼ of the sum of the diameters of adjacent containers [5 ft (1.5 m) minimum]	

*If the aggregate water capacity of a multiple container installation is 501 gal (1.9 m^3) or greater, the minimum distance must comply with the appropriate portion of this table, applying the aggregate capacity rather than the capacity per container. If more than one installation is made, each installation must be separated from any other installation by at least 25 ft (7.6 m). Do not apply minimum distances between adjacent containers to such installation.

N **6.3.2.1.2** The design of the outer concrete container shall take into account the following factors:

(1) Reduction in the wall post-tensioning due to the difference in the coefficient of thermal expansion of post-tensioning steel and wall concrete at the temperature to which the post-tensioning steel is exposed, taking into consideration the effects of the concrete aggregate type on the concrete coefficient of thermal expansion
(2) Reduction in strength and modulus of elasticity of the outer tank concrete, reinforcing and post-tensioning steel due to elevated temperature
(3) Reduction in the wall post-tensioning due to pre-stressing steel softening and relaxation at elevated temperature

N **6.3.3** A clear space of at least 3 ft (0.9 m) shall be provided for access to all isolation valves serving multiple containers.

N **6.3.4** LNG containers of greater than 125 gal (0.5 m^3) capacity shall not be located in buildings.

N **6.3.5** Flammable liquid and flammable refrigerant storage tanks shall not be located within an LNG container impounding area.

N **6.4 Vaporizer Spacing.**

N **6.4.1** Vaporizers using flammable heat transfer fluids and their primary heat sources shall be located at least 50 ft (15 m) from any other source of ignition.

N **6.4.1.1** Where more than one vaporizer is installed at one location, an adjacent vaporizer or primary heat source shall not be considered to be a source of ignition.

N **6.4.1.2** Process heaters or other units of fired equipment shall not be considered to be sources of ignition with respect to vaporizer siting if they are interlocked so that they cannot be operated while a vaporizer is operating or while the piping system serving the vaporizer either is cooled down or is being cooled down.

N **6.4.2*** The fired components of an integral heated vaporizer shall be located as follows

(1) At least 50 ft (15 m) from any impounded LNG, flammable refrigerant, or flammable liquid *(see Section 6.3)* or the paths of travel of such fluids between any other source of accidental discharge and the impounding area
(2) At least 50 ft (15 m) from LNG, flammable liquid, flammable refrigerant, or flammable gas storage containers or tanks; unfired process equipment containing such fluids; or loading and unloading connections used in the transfer of such fluids
(3) At least 50 ft (15 m) from control buildings, offices, shops, and other occupied or important plant structures
(4) At least 100 ft (30 m) from property line that can be built upon *(see 6.4.4)*

N **6.4.3** Heaters or heat sources of remote heated vaporizers shall comply with 6.4.2.

N **6.4.4** Remote heated, ambient, and process vaporizers shall be located at least 100 ft (30 m) from a property line that can be built upon.

N **6.4.5** Vaporizers used in conjunction with LNG containers having a capacity of 70,000 gal (265 m^3) or less shall be located with respect to the property line in accordance with Table 6.3.1, assuming the vaporizer to be a container with a capacity equal to the largest container to which it is connected.

N **6.4.6** A clearance of at least 5 ft (1.5 m) shall be maintained between vaporizers.

N **6.5 Process Equipment Spacing.**

N **6.5.1** Process equipment containing LNG, refrigerants, flammable liquids, or flammable gases shall be located at least 50 ft (15 m) from sources of ignition, a property line that can be built upon, control centers, offices, shops, and other occupied structures.

N **6.5.2** Where control centers are located in a building housing flammable gas compressors, the building construction shall comply with Section 12.5.

N **6.5.3** Fired equipment and other sources of ignition shall be located at least 50 ft (15 m) from any impounding area or container drainage system.

N **6.6 Loading and Unloading Facility Spacing.**

N **6.6.1** A pier or dock used for pipeline transfer of LNG shall be located so that any marine vessel being loaded or unloaded is at least 100 ft (30 m) from any bridge crossing a navigable waterway.

N **6.6.2** The loading or unloading manifold shall be at least 200 ft (61 m) from such a bridge.

N **6.6.3*** LNG and flammable refrigerant loading and unloading connections shall be at least 50 ft (15 m) from uncontrolled sources of ignition, process areas, storage containers, control buildings, offices, shops, and other occupied or important plant structures unless the equipment is directly associated with the transfer operation.

N **6.6.4*** Impounding areas shall be located so that the heat flux from a fire over the impounding area shall not cause major structural damage to any LNG marine carrier that could prevent its movement.

N **6.7 Buildings and Structures.**

N **6.7.1** Buildings or structural enclosures not covered by Sections 12.5 through 12.7 shall be located, or provisions otherwise shall be made, to minimize the possibility of entry of flammable gases or vapors.

N **6.7.2** Buildings not covered by Sections 12.5 through 12.7 shall be located no less than 50 ft (15 m) from tanks, vessels, and gasketed or sealed connections to equipment containing LNG and other hazardous fluids.

N **6.8 Impoundment Spacing.**

N **6.8.1** Impoundments shall be located such that design spill hazards do not extend offsite in accordance with Chapter 5.

N **6.8.2** Impoundments shall be located such that they meet the spacing requirements in Table 6.3.1.

N **6.8.3** Impoundments shall be at least 50 ft (15 m) from uncontrolled sources of ignition, control buildings, offices, shops, and other occupied or important plant structures.

 Shaded text = Revisions. Δ = Text deletions and figure/table revisions. • = Section deletions. *N* = New material.

Chapter 7 Process Equipment

7.1 Scope. This chapter applies to the requirements for the design and installation of process equipment.

N **7.1.1 General Requirement.** Equipment including associated foundations shall be designed in accordance with the seismic, wind, ice, flood, and snow criteria in Section 12.2.

7.2 Installation of Process Equipment.

7.2.1 Process system equipment containing LNG or other hazardous fluids shall be installed in accordance with one of the following:

(1) Outdoors, for ease of operation, to facilitate manual firefighting, and to facilitate dispersal of accidentally released liquids and gases
(2) Indoors, in enclosing structures that comply with Sections 12.5 through 12.7

Δ **7.2.2** Welding and brazing of process equipment shall conform to the following:

(1) Welding and brazing of process equipment shall conform to the requirements of the standard to which the equipment is designed and constructed *(see 7.5.2 through 7.5.6.2)*.
(2) All welding or brazing operations shall be performed with procedures qualified to Section IX of the ASME *Boiler and Pressure Vessel Code*.
(3) All welding or brazing shall be performed by personnel qualified to the requirements of Section IX of the ASME *Boiler and Pressure Vessel Code*.

7.3* Pumps and Compressors.

N **7.3.1*** Pumps and compressors shall be designed and fabricated in accordance with recognized standards.

N **7.3.2*** Seals shall be designed in accordance with recognized standards.

7.3.3 Pumps and compressors shall be constructed of materials selected for compatibility with the design temperature and pressure conditions.

7.3.4* Valving shall be installed so that each pump or compressor can be isolated for maintenance.

7.3.5 Where pumps or centrifugal compressors are installed for operation in parallel, each discharge line shall be equipped with a check valve.

7.3.6 Pumps and compressors shall be provided with a pressure-relieving device on the discharge to limit the pressure to the maximum design pressure of the casing and downstream piping and equipment, unless they are designed for the maximum discharge pressure of the pumps and compressors.

7.3.7 Each pump shall be provided with a vent, relief valve, or both that will prevent overpressuring of the pump case during the maximum possible rate of cooldown.

7.3.8 Compression equipment that handles flammable gases shall be provided with vents from all points where gases normally can escape. Vents shall be piped outside of buildings to a point of safe disposal.

N **7.3.9*** Blowers and fans shall be designed in accordance with recognized standards.

N **7.3.10*** Turbines shall be designed in accordance with recognized standards.

N **7.3.11*** Motors shall be designed in accordance with recognized standards.

7.4 Flammable Refrigerant and Flammable Liquid Storage.

N **7.4.1** Storage containers and equipment for hazardous fluids other than LNG shall comply with NFPA 30; NFPA 58; NFPA 59; API Std 2510, *Design and Construction of Liquefied Petroleum Gas (LPG) Installations*, as applicable; or Section 5.3 of this standard.

N **7.4.2*** Design and specification of storage tanks for hazardous liquids shall be in accordance with recognized standards.

N **7.4.3*** Venting of atmospheric and low-pressure hazardous liquid tanks shall be in accordance with recognized standards.

7.5 Process Equipment.

7.5.1 The maximum allowable working pressure shall be documented for process equipment.

7.5.2 Boilers shall be designed and fabricated in accordance with the ASME *Boiler and Pressure Vessel Code*, Section I, or with CSA B51, *Boiler, Pressure Vessel and Pressure Piping Code*.

N **7.5.3*** Fired heaters shall be designed in accordance with recognized standards.

N **7.5.4*** Burner management systems shall be designed in accordance with recognized standards.

Δ **7.5.5*** Pressure vessels shall be designed and fabricated in accordance with Section VIII, Division 1 or Division 2, of the ASME *Boiler and Pressure Vessel Code* or with CSA B51, *Boiler, Pressure Vessel and Pressure Piping Code*, and shall be code-stamped. Pressure vessels (austenitic stainless steel) designed and manufactured utilizing cold stretching techniques shall be approved for use by the AHJ.

7.5.6* Heat exchangers shall be designed and fabricated in accordance with recognized standards.

N **7.5.6.1** Shell and tube heat exchangers shall be designed and fabricated in accordance with Section VIII, Division 1 or Division 2, of the ASME *Boiler Pressure Vessel Code* or with CSA B51, *Boiler, Pressure Vessel and Pressure Piping Code*, where such components fall within the jurisdiction of the pressure vessel code.

Δ **7.5.6.2** Brazed aluminum plate fin heat exchangers shall be designed and fabricated in accordance with Section VIII, Division 1 or Division 2, of the ASME *Boiler and Pressure Vessel Code* and ALPEMA *Standards of the Brazed Aluminum Plate-Fin Heat Exchanger Manufacturer's Association*.

7.5.7* Installation of internal combustion engines or gas turbines not exceeding 7500 horsepower per unit shall conform to NFPA 37.

N **7.5.8*** Flares installed to serve as part of a system emergency depressurization or other process purposes shall be in accordance with recognized standards.

7.5.9 A boil-off and flash gas-handling system separate from container relief valves shall be installed for the safe disposal of vapors generated in the process equipment and LNG containers.

7.5.9.1 Boil-off and flash gases shall discharge into a closed system or into the atmosphere so that they do not create a hazard to people, equipment, or adjacent properties.

7.5.9.2 The boil-off venting system shall be designed so that it cannot inspirate air during normal operation.

7.5.10 If internal vacuum conditions can occur in any piping, process vessels, cold boxes, or other equipment, either the piping and equipment subject to vacuum shall be designed to withstand the vacuum conditions or provision shall be made to prevent vacuum. If gas is introduced for the purpose of preventing a vacuum condition, it shall not create a flammable mixture within the system.

Chapter 8 Stationary LNG Storage

Δ **8.1 Scope.** This chapter presents the requirements for the inspection, design, marking, testing, and operation of stationary LNG tank systems and ASME containers.

8.2 General.

8.2.1 Storage Tank Systems.

8.2.1.1 Storage tank systems, including membrane containment tank systems, shall comply with the requirements of API Std 625, *Tank Systems for Refrigerated Liquefied Gas Storage*, and the additional provisions of this chapter. The API Std 625 risk assessment shall be approved by the AHJ.

Δ **8.2.1.2** Metal containers that are part of an LNG storage tank system shall comply with API Std 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*, and the further requirements in Section 8.4.

8.2.1.3 Concrete and metal-lined composite concrete containers that are part of an LNG storage tank system shall comply with ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containments of Refrigerated Liquefied Gases*, and the requirements of Section 8.4.

8.2.1.4 The metallic membrane, load-bearing insulation, and the outer container moisture barrier specific to the membrane tank system shall comply with EN 14620, *Design and manufacture of site built, vertical, cylindrical, flat-bottomed, steel tanks for the storage of refrigerated, liquefied gases with operating temperatures between 0°C and −165°C*, Parts 1–5, for material selection, design, installation, examination, and testing and further requirements of Section 8.4. All other components of the membrane tank system shall comply with API Std 625, *Tank Systems for Refrigerated Liquefied Gas Storage*; API Std 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*; ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases*; and additional requirements in Section 8.4.

8.2.1.5 Should any conflict exist among the requirements in 8.2.1.1 through 8.4.7, the most stringent requirement shall apply.

8.2.2 ASME Containers. ASME containers shall comply with the requirements of Section 8.5 and Section VIII of the ASME *Boiler and Pressure Vessel Code* and shall be ASME-stamped and registered with the National Board of Boiler and Pressure Vessel Inspectors or other agencies that register pressure vessels.

8.3 Design Considerations.

8.3.1 General.

8.3.1.1 Those parts of LNG containers that normally are in contact with LNG and all materials used in contact with LNG or cold LNG vapor [vapor at a temperature below −20°F (−29°C)] shall be physically and chemically compatible with LNG and intended for service at −270°F (−168°C).

8.3.1.2 The density of the liquid shall be assumed to be the actual mass per unit volume at the minimum storage temperatures, except that the minimum density for design purposes shall be 29.3 lb/ft^3 (470 kg/m^3).

8.3.2 Wind, Flood, and Snow Loads.

Δ **8.3.2.1** The wind, flood, including hurricane storm surge, and snow loads for the design of LNG tank systems and LNG storage containers shall be determined using the procedures outlined in ASCE 7, *Minimum Design Loads and Associated Criteria for Buildings and Other Structures*, as modified in this standard.

8.3.2.1.1 For determining flood and hurricane storm surge design hazards, a 500-year mean occurrence interval including relative sea level rise and wind-driven wave effects shall be used.

N **8.3.2.1.2** For snow loads, where a probabilistic approach is used, a 100-year mean occurrence interval shall be used.

N **8.3.2.1.3** LNG tank systems and LNG containers shall be designed for or otherwise protected from wind, flood, storm surge, and snow loads.

8.3.2.2* Basic design wind speed shall be based on a 10,000-year mean occurrence interval for LNG storage containers and for structures, equipment, and piping supported by the LNG storage containers and ASCE 7, Risk Category IV for all other structures supporting equipment.

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8.3.3 Marking of LNG Tank Systems and ASME Containers.

8.3.3.1 Each LNG tank system shall be identified by the attachment in an accessible location of a corrosion-resistant nameplate as defined in API Std 625, *Tank Systems for Refrigerated Liquefied Gas Storage*.

Δ **8.3.3.2** ASME containers shall be identified by the attachment of a corrosion-resistant nameplate as required by Section VIII of the ASME *Boiler and Pressure Vessel Code*.

8.3.3.3 Storage tank systems shall have all penetrations marked with the function of the penetration.

8.3.3.4 Penetration markings shall be visible if frosting occurs.

8.3.4 Foundations.

8.3.4.1* LNG containers shall be installed on foundations designed by a qualified engineer and constructed in accordance with recognized structural engineering practices.

8.3.5 Inspection.

8.3.5.1 Prior to initial operation, tank systems shall be inspected to ensure compliance with the engineering design and material, fabrication, assembly, and test provisions of this standard.

8.3.5.2 The inspection shall be conducted by inspectors who are employees of the operator, an engineering or scientific organization, or a recognized insurance or inspection company.

8.3.5.3 Inspectors shall be qualified in accordance with the code or standard applicable to the container and as specified in this standard.

N **8.3.6 Welding on Containers after Acceptance Testing is Completed.**

Δ 8.3.6.1 After acceptance tests are completed, there shall be no field welding on the LNG containers, except as permitted in 8.3.6.1.1 and 8.3.6.1.2.

8.3.6.1.1 Field welding shall be limited to saddle plates or brackets provided for the purpose and to repairs and temporary opening restorations permitted under the code or standard of fabrication.

8.3.6.1.2 Retesting by a method appropriate to the repair or modification shall be required only where the repair or modification is of such a nature that a retest actually tests the element affected and is necessary to demonstrate the adequacy of the repair or modification.

N **8.3.7 Buried and Underground Containers.**

N **8.3.7.1** Buried and underground containers shall be provided with means to prevent the 32°F (0°C) isotherm from penetrating the soil.

N **8.3.7.2** Where heating systems are used, they shall be installed such that any heating element or temperature sensor used for control can be replaced.

N **8.3.7.3*** All buried or mounded components in contact with the soil shall be constructed from material resistant to soil corrosion or protected to minimize corrosion.

8.4 Tank Systems.

8.4.1 General.

8.4.1.1* Certification. Upon completion of all tests and inspections of each LNG tank system, the contractor shall certify to the purchaser that the LNG tank system has been constructed in accordance with the applicable requirements of this standard.

8.4.2 All piping that is a part of an LNG tank system shall comply with requirements in this chapter and requirements within API Std 625, *Tank Systems for Refrigerated Liquefied Gas Storage.*

8.4.2.1 Tank system piping shall include all piping internal to the container, within insulation spaces and within void spaces, external piping attached or connected to the container up to the first circumferential external joint of the piping, and external piping serving only tank system instrumentation (including tank system pressure relief valves). All liquid piping with a source of external line pressure shall be designed for the external line relief valve setting but not less than 50 psi (345 kPa). Double, full, and membrane containment tank systems shall have no pipe penetrations below the liquid level.

8.4.2.2 Inert gas purge systems wholly within the insulation spaces and relief valve discharge piping shall be exempt from compliance.

8.4.3* All LNG tank systems shall be designed for both top and bottom filling unless other process means are provided to mitigate stratification.

8.4.4 Any portion of the outer surface area of an LNG tank system or external members whose failure could result in loss of containment from accidental exposure to low temperatures resulting from the leakage of LNG or cold vapor from flanges, valves, seals, or other nonwelded connections shall be designed for such temperatures or otherwise protected from the effects of low-temperature exposure.

8.4.5 Where two or more tank systems are sited in a common dike, each tank system foundation shall be capable of withstanding contact with LNG or shall be protected against contact with an accumulation of LNG that might endanger structural integrity.

8.4.6* Provisions shall be made for removal of the tank system from service.

8.4.7 All the membrane tank system components, including insulation, primary membrane, and the secondary barrier of the thermal protection system where required, shall be designed in such a way that they can withstand all credible combinations of static and dynamic actions throughout the tank system lifetime.

8.4.8 Container Insulation.

8.4.8.1 Exposed insulation shall be noncombustible, shall contain or inherently shall be a vapor barrier, shall be water-free, and shall resist dislodgment by fire hose streams.

8.4.8.1.1 Where an outer shell is used to retain loose insulation, the shell shall be constructed of steel or concrete.

8.4.8.1.2 Exposed weatherproofing shall have a flame spread index not greater than 25. *(See 3.3.14.)*

8.4.8.2 The space between the inner container and the outer container shall contain insulation that is compatible with LNG and natural gas and that is noncombustible as installed for all conditions in service and meet the requirements in 8.4.8.2.1 through 8.4.8.2.6.

8.4.8.2.1 A fire external to the outer container shall not cause damage to the insulation system and a reduction to the internal containment system performance due to damage to any component of the insulation systems.

8.4.8.2.2 The load-bearing bottom insulation shall be designed and installed so that cracking from thermal and mechanical stresses does not jeopardize the integrity of the container.

8.4.8.2.3 It shall be shown by test that the combustion properties of the material do not increase significantly as a result of long-term exposure to LNG or natural gas at the anticipated service pressure and temperature.

N **8.4.8.2.4** The materials in the installed condition shall be demonstrated to be capable of being purged of natural gas to the point where the natural gas remaining after purging does not increase the combustibility of the material.

8.4.8.2.5 The materials in the installed condition shall not support continued progressive combustion in air.

N **8.4.8.2.6** The following mitigation measures are to be provided during construction and after decommissioning for repair work:

(1) No hot work, which can cause insulation combustion, shall be performed in the vicinity of insulation after it's installed or after decommissioning for repair work unless insulation is properly protected from ignition sources.
(2) Any tool or equipment used during insulation construction or repair that has potential to introduce hazardous levels of heat to combustible insulation components shall require fail-safe temperature controls to ensure that applied heat does not exceed required limits.
(3) The repair procedures in insulation vicinity shall be approved by the AHJ.

8.4.8.3 Tank systems insulation shall meet the requirements of Section 9 of API Std 625, *Tank Systems for Refrigerated Liquefied Gas Storage*.

8.4.9 Container Drying, Purging, and Cooldown. Before an LNG tank system is put into service, it shall be dried, purged, and cooled in accordance with 18.3.5 and 18.6.5, and tank systems shall include the provisions within API Std 625, *Tank Systems for Refrigerated Liquefied Gas Storage*, and/or ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases*, as applicable to the type of tank system construction.

8.4.10 Relief Devices.

8.4.10.1 All LNG containers shall be equipped with vacuum and pressure relief valves as required by the code or standard of manufacture.

8.4.10.2 In-service pressure and vacuum relief devices shall communicate directly with the atmosphere.

8.4.10.3 Vacuum-relieving devices shall be installed if the container can be exposed to a vacuum condition in excess of that for which the container is designed.

8.4.10.4 Each pressure and vacuum safety relief valve for LNG tank systems shall be able to be isolated from the tank systems for maintenance or other purposes by means of a manual full-opening stop valve.

8.4.10.4.1 The stop valve(s) shall be lockable or sealable in the fully open position.

8.4.10.4.2 Pressure and vacuum relief valves shall be installed on the LNG tank system to allow each relief valve to be isolated individually while maintaining the required relieving capacity.

8.4.10.4.3 Where only one relief device is required, either a full-port opening three-way valve connecting the relief valve and its spare to the container or two relief valves separately connected to the container, each with a valve, shall be installed.

8.4.10.4.4 No more than one stop valve shall be closed at one time.

8.4.10.4.5 Safety relief valve discharge stacks or vents shall be designed and installed to prevent an accumulation of water, ice, snow, or other foreign matter and shall discharge vertically upward.

8.4.10.5 Pressure Relief Device Sizing.

8.4.10.5.1 The capacity of pressure relief devices shall be based on the following:

(1) Fire exposure
(2) Operational upset, such as failure of a control device
(3) Other circumstances resulting from equipment failures and operating errors
(4) Vapor displacement during filling
(5) Flash vaporization during filling, as a result of filling or as a consequence of mixing of products of different compositions
(6) Loss of refrigeration
(7) Heat input from pump recirculation
(8) Drop in barometric pressure

8.4.10.5.2 Pressure relief devices shall be sized to relieve the flow capacity determined for the largest single relief flow or any reasonable and probable combination of relief flows.

8.4.10.5.3* The minimum pressure-relieving capacity in pounds per hour (kilograms per hour) shall not be less than 3 percent of the full tank system contents in 24 hours.

8.4.10.6 Vacuum Relief Sizing.

8.4.10.6.1 The capacity of vacuum relief devices shall be based on the following:

(1) Withdrawal of liquid or vapor at the maximum rate
(2) Rise in barometric pressure
(3) Reduction in vapor space pressure as a result of filling with subcooled liquid

8.4.10.6.2 The vacuum relief devices shall be sized to relieve the flow capacity determined for the largest single contingency or any reasonable and probable combination of contingencies, less the vaporization rate that is produced from the minimum normal heat gain to the container contents.

8.4.10.6.3 No vacuum relief capacity credit shall be allowed for gas-repressuring systems or vapor makeup systems.

8.4.10.7 Fire Exposure.

8.4.10.7.1 The pressure-relieving capacity required for fire exposure shall be computed by the following formulas:

For U.S. customary units:

[8.4.10.7.1a]

$$H = 34{,}500\ FA^{0.82} + H_n$$

For SI units:

[8.4.10.7.1b]

$$H = 71{,}000\ FA^{0.82} + H_n$$

where:
H = total heat influx [Btu/hr (watt)]
F = environmental factor from Table 8.4.10.7.1
A = exposed wetted surface area of the container [ft^2 (m^2)]
H_n = normal heat leak in refrigerated tanks [Btu/hr (watt)]

Δ Table 8.4.10.7.1 Environmental Factors

Basis	*F* Factor
Base container	1.0
Water application facilities	1.0
Depressuring and emptying facilities	1.0
Underground container	0
Insulation or thermal protection*	
U.S. customary units	$F = \frac{U(1660 - T_f)}{34{,}500}$
SI units	$F = \frac{U(904 - T_f)}{71{,}000}$

*U = overall heat transfer coefficient Btu/(hr · ft² ·°F) [W/(m² ·°C)] of the insulation system using the mean value for the temperature range from T_f to +1660°F (904°C); T_f = temperature of vessel content at relieving conditions, °F (°C).

8.4.10.7.2 The exposed wetted area shall be the area up to a height of 30 ft (9 m) above grade.

8.4.10.7.3* Where used, insulation shall resist dislodgment by fire-fighting equipment, shall be noncombustible, and shall not decompose at temperatures up to 1000°F (538°C) in order for the environmental factor for insulation to be used.

8.4.10.7.4 Pressure Relief Valve Capacity.

8.4.10.7.4.1 The relieving capacity shall be determined by the following formula:

[8.4.10.7.4.1]

$$W = \frac{H}{L}$$

where:
W = relieving capacity of product vapor at relieving conditions [lb/hr (g/s)]
H = total heat influx, Btu/hr (watt)
L = latent heat of vaporization of the stored liquid at the relieving pressure and temperature, Btu/lb (J/g)

8.4.10.7.4.2 The equivalent airflow shall be calculated from the following formulas:

For U.S. customary units:

[8.4.10.7.4.2a]

$$Q_a = 3.09W\frac{\sqrt{TZ}}{\sqrt{M}}$$

For SI units:

[8.4.10.7.4.2b]

$$Q_a = 0.93W\frac{\sqrt{TZ}}{\sqrt{M}}$$

where:
Q_a = equivalent flow capacity of air at 60°F (15°C) and absolute pressure of 14.7 psi (101 kPa) [ft³/hr (m³/hr)]
W = relieving capacity of product vapor at relieving conditions [lb/hr (g/s)]
T = absolute temperature of product vapor at relieving conditions [°R (K)]
Z = compressibility factor of product vapor at relieving condition
M = product vapor molecular mass [lbm/lb mol (g/g mol)]

8.4.11 Foundations.

N **8.4.11.1** Tank systems foundations shall be designed in accordance with ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases.*

8.4.11.2 Investigation and Evaluation.

N **8.4.11.2.1** Prior to the start of design and construction of the foundation, a subsurface investigation and evaluation shall be conducted by a geotechnical engineer to determine the stratigraphy and physical properties of the soils underlying the site.

N **8.4.11.2.2** A liquefaction evaluation in accordance with 11.8.3 of ASCE 7, *Minimum Design Loads and Associated Criteria for Buildings and Other Structures*, shall be included as part of the evaluation in 8.4.11.2.1.

8.4.11.3 The bottom of the outer container shall be above the groundwater table or protected from contact with groundwater at all times.

8.4.11.4 The outer container bottom material in contact with soil shall meet one of the following requirements:

(1) Selected to minimize corrosion
(2) Coated or protected to minimize corrosion
(3)* Protected by a cathodic protection system

8.4.11.5 Where no air gap exists under the tank system foundation, a heating system shall be provided to prevent the 32°F (0°C) isotherm from penetrating the soil.

8.4.11.5.1 The heating system shall be designed to allow functional and performance monitoring.

8.4.11.5.2 Where there is a discontinuity in the foundation, such as for bottom piping, attention and separate treatment shall be given to the heating system in this zone.

8.4.11.5.3 Heating systems shall be designed, selected, and installed so that any heating element and temperature sensor used for control can be replaced after installation.

8.4.11.5.4* Provisions shall be incorporated to prevent moisture accumulation in the conduit.

8.4.11.6 If the foundation is designed to provide air circulation in lieu of a heating system, the bottom of the outer container shall be of a material compatible with the temperatures to which it can be exposed.

8.4.11.7 A container bottom temperature monitoring system capable of measuring the temperature on a predetermined pattern over the entire surface area in order to monitor the performance of the bottom insulation and the container foundation heating system (if provided) shall be installed.

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N **8.4.11.8** Benchmarks for foundation elevation surveys shall be installed and used before, during, and after hydrostatic testing, and at three-month intervals until the settlement has become predictable.

8.4.12 Metal Containers.

8.4.12.1 Welded containers designed for not more than 15 psi (103 kPa) shall comply with API Std 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*.

8.4.12.2* Appendix Q of API Std 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks,* shall be applicable for LNG, except that the frequency of examination by radiography or ultrasonic methods in primary and secondary liquid containers shall be increased to 100 percent for all butt welds in the cylindrical shell (except for the shell-to-bottom welds associated with a flat bottom container) and all butt-welded annular plate radial joints.

8.4.12.3 Weld Procedure and Production Weld Testing for Membrane Containment Tank Systems. For membrane containment tank systems, weld procedure and production weld testing shall comply with EN 14620, *Design and manufacture of site built, vertical, cylindrical, flat-bottomed, steel tanks for the storage of refrigerated, liquefied gases with operating temperatures between 0°C and −165°C,* Part 2, and the requirements in 8.4.12.3.1 through 8.4.12.3.5.

8.4.12.3.1 Qualification of Welders. All personnel associated with the welding fabrication of the membrane system shall be qualified by the manufacturer per an agreed-upon schedule between the purchaser, the AHJ, and the fabricator, and all records shall be available for review.

8.4.12.3.2 Inspection. One hundred percent of all welds shall be visually examined for workmanship and conformance to the fabrication requirements by a qualified welding inspector.

8.4.12.3.2.1 Bead placement and consistency shall be, at a minimum, documented by digital means for review by supervisory personnel.

8.4.12.3.2.2 Upon cooldown of the welds to room temperature, provisions shall be made to perform a penetrant test (PT) of at least 5 percent of each weld type each day, subject to the following requirements:

(1) Selection factors shall include orientation, welding direction, and the complexity of the welding being performed.
(2) All profiles and configurations of welds shall be subjected to the 5 percent requirement, and the selection of this 5 percent sample shall be agreed upon by the fabricator, the customer's representative, and the AHJ.
(3) The acceptance standard for this inspection technique shall be agreed upon by all parties.
(4) Any indication of a leak shall require an additional 5 percent PT of the total distance welded by each welder.

Δ **8.4.12.3.2.3** Inspection after completion of the membrane shall include a leakage test in parallel with a mechanical stress test as follows:

(1) The leakage test procedure shall be agreed upon by the manufacturer and the customer and approved.
(2) Tracer gas for the leak test shall be in accordance with an approved procedure.
(3) Mechanical stress testing of the welding joints shall be performed by applying three cycles from atmospheric pressure to +20 mbarg inside the insulation space, with the pressure maintained, for a minimum time of 30 minutes, and the data shall be recorded.
(4) All areas where leakage occurs shall be repaired and inspected per 8.4.12.3.2 and the manufacturer's procedure.

8.4.12.3.3 Post-Repair Inspection.

Δ **8.4.12.3.3.1** Additional tracer gas testing shall be performed if more than four leaks per 1000 m^2 of membrane are identified.

8.4.12.3.3.2 All repaired areas shall be visually inspected (VT), vacuum box (VB) tested, and dye penetrant (PT) tested.

Δ **8.4.12.3.4 Final Global Test.** The final acceptance testing of the completed membrane structure following completion of its installation in the structural outer shell/container shall be in agreement with the approved test procedure and witnessed by all relevant parties and performed as follows:

(1) The overall tightness of the membrane shall be determined by establishing a pressure difference between the tank and the insulation space, which allows gas flow through the membrane representative of potential leaks on the membrane.
(2) The potential leak(s) shall be characterized by measuring the oxygen content increase in the primary insulated space as the tank is pressurized with dry air.
(3) The primary insulated space shall be regulated above the ambient pressure.
(4) All test data, records, documentation, and witness records shall be submitted to all parties for review and final acceptance.

8.4.12.3.5 Control During Removal of Construction Equipment.

N **8.4.12.3.5.1** A daily tightness check and monitoring shall be performed during removal of construction equipment by pulling vacuum inside insulated spaces.

N **8.4.12.3.5.2** Any pressure rise, which is indicative of a leak, shall be reported and corrective action shall be taken.

8.4.13 Concrete Containers.

8.4.13.1 The design, construction, inspection, and testing of concrete containers shall comply with ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases*.

8.4.13.2 A tank system with unlined concrete primary liquid containment shall include a means of detecting and eliminating liquid accumulation in the annular space.

8.4.13.3 Non-metallic coatings placed on a concrete container acting as a moisture and/or product vapor barrier shall meet

 Shaded text = Revisions. Δ = Text deletions and figure/table revisions. • = Section deletions. *N* = New material.

the criteria in ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases*.

8.4.13.4 Metallic barriers incorporated in, and functioning compositely with, concrete containers shall be of a metal defined in Appendix Q of API Std 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*.

8.4.14 Seismic Design of Land-Based Field-Fabricated Tank Systems.

8.4.14.1 A site-specific investigation shall be performed for all installations except those provided for in 8.5.2 to determine the characteristics of seismic ground motion and associated response spectra.

Δ **8.4.14.1.1** The site-specific investigation performed in accordance with ASCE 7, *Minimum Design Loads and Associated Criteria for Buildings and Other Structures,* shall account for the regional seismicity and geology, the expected recurrence rates and maximum magnitudes of events on known faults and source zones, the location of the site with respect to these seismic sources, near source effects, if any, and the characteristics of subsurface conditions.

Δ **8.4.14.1.2** On the basis of the site-specific investigation, the ground motion of a maximum considered earthquake (MCE_R) shall be the motion having a 2 percent probability of exceedance within a 50-year period (mean recurrence interval of 2475 years), adjusted by the requirements of ASCE 7, *Minimum Design Loads and Associated Criteria for Buildings and Other Structures*.

N **8.4.14.1.3 Maximum Considered Tsunamis.**

N **8.4.14.1.3.1** The maximum considered tsunamis (MCT_R) shall be based on a 2 percent probability of exceedance within a 50-year period (i.e., mean recurrence interval of 2,475 years), adjusted by the requirements of ASCE 7, *Minimum Design Loads for Buildings and Other Structures*.

N **8.4.14.1.3.2** The LNG outer container foundation shall be designed or otherwise protected from tsunami wave effects in accordance with the requirements of ASCE 7, *Minimum Design Loads and Associated Criteria for Buildings and Other Structures*.

8.4.14.1.4 For the MCE_R ground motion, vertical and horizontal acceleration response spectra shall be constructed covering the entire range of anticipated damping ratios and natural periods of vibration, including the fundamental period and damping ratio for the sloshing (convective) mode of vibration of the contained LNG.

Δ **8.4.14.1.5** The MCE_R response spectral acceleration for any period, *T*, shall correspond to a damping ratio that best represents the structure being investigated as specified in Appendix L of API Std 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks,* and ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases*.

8.4.14.1.6 Vertical Response Spectrum.

N **8.4.14.1.6.1** If information is not available to develop a vertical response spectrum, the ordinates of the vertical response spectrum shall not be less than two-thirds of those of the horizontal spectrum.

N **8.4.14.1.6.2** If information is available, the corresponding ratio shall not be less than one-half.

8.4.14.2 The LNG tank systems and their impounding systems shall be designed for the following three levels of seismic ground motion:

(1) Safe shutdown earthquake (SSE) as defined in 8.4.14.3
(2) Operating basis earthquake (OBE) as defined in 8.4.14.4
(3) Aftershock level earthquake (ALE) as defined in 8.4.14.5

8.4.14.3 The SSE shall be represented by a ground motion response spectrum in which the spectral acceleration at any period, *T,* shall be equal to the spectral acceleration of the MCE_R ground motion defined in 8.4.14.1.

Δ **8.4.14.4*** The OBE ground motion shall be the motion represented by an acceleration response spectrum having a 10 percent probability of exceedance within a 50-year period (mean return interval of 475 years) that represents the maximum response in the horizontal plane. If a site-specific analysis is carried out, the site-specific OBE spectra shall represent the maximum response. The site-specific OBE spectra shall not be less than 80 percent of the USGS spectra, or equivalent, adjusted for local site conditions and scaled to the maximum response in accordance with Chapter 21.2 of ASCE 7, *Minimum Design Loads and Associated Criteria for Buildings and Other Structures*.

8.4.14.5 The ALE ground motion is defined as one-half SSE.

Δ **8.4.14.6** The three levels of ground motion defined in 8.4.14.3 through 8.4.14.5 shall be used for the earthquake-resistant design of the following structures and systems:

(1) LNG tank systems and their impounding systems
(2) System components required to isolate the LNG tank system and maintain it in a safe shutdown condition
(3) Structures or systems, including fire protection systems, the failure of which could affect the integrity of 8.4.14.6(1) or 8.4.14.6(2)

8.4.14.6.1 The structures and systems shall be designed to remain operable during and after an OBE.

8.4.14.6.2 The OBE design shall be based on a response reduction factor equal to 1.0.

8.4.14.6.3 The SSE design shall provide for no loss of containment capability of the primary container of single, double, and full containment tank systems and of the metal liquid barrier of membrane tank systems, and it shall be possible to isolate and maintain the LNG tank systems during and after the SSE.

8.4.14.6.4 Response Reduction Factors.

N **8.4.14.6.4.1** Where used, response reduction factors applied in the SSE design shall be demonstrated not to reduce the performance criteria in 8.4.14.6.3.

N **8.4.14.6.4.2** The values in Appendix L of API Std 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks,* shall be considered compliant for steel containers of the tank systems, and Section 8 of ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases,* shall be considered compliant for concrete container(s) of the tank system.

8.4.14.7 The secondary liquid container or impounding system for single, double, or full containment tanks shall, as a minimum, be designed to withstand an SSE while empty and an ALE while holding a volume equivalent to the primary containment liquid at the maximum normal operating level as defined in API Std 625, *Tank Systems for Refrigerated Liquefied Gas Storage.*

8.4.14.8 Membrane Tank System.

N **8.4.14.8.1** For the membrane tank system, all components of the product-containing structure, including the liquid barrier, insulation system, thermal corner protection system *(see 8.4.16.1)* where required, and the outer concrete container, shall be designed to withstand without loss of function an SSE event with the tank filled to the maximum normal operating level.

N **8.4.14.8.2** The outer concrete container and the thermal corner protection shall be designed to withstand an ALE with a tank full to the maximum normal operating level assuming that the membrane has failed and that the outer concrete container wall and thermal corner protection system are exposed to LNG.

8.4.14.9 An LNG tank system shall be designed for the OBE, SSE, and ALE in accordance with API Std 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*, and ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases.*

8.4.14.10 After an event exceeding OBE, the tank system shall be evaluated for safe continued operation. After an SSE event, the container shall be emptied and inspected prior to resumption of container-filling operations.

8.4.14.11 The design of the LNG tank systems and structural components shall be in accordance with API Std 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*, or ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases.*

N **8.4.14.11.1** Soil-structure interaction (SSI) shall be included where the tank system is not founded on bedrock (Site Class A or B per ASCE 7, *Minimum Design Loads and Associated Criteria for Buildings and Other Structures*).

N **8.4.14.11.2** SSI shall be permitted to be performed in accordance with the requirements of ASCE 7, *Minimum Design Loads and Associated Criteria for Buildings and Other Structures.*

N **8.4.14.11.3** Reductions in seismic design loads due to SSI effects shall not exceed those permitted by ASCE 7, *Minimum Design Loads and Associated Criteria for Buildings and Other Structures.*

8.4.14.12 The outer concrete container analysis and design for the leak and leak plus ALE event shall take into account any damage that might have occurred to the outer concrete container due to prior events, including the SSE earthquake.

8.4.14.12.1 The outer concrete container shall be considered as undamaged during the prior SSE event if the following conditions are met:

(1) Tensile stresses in the reinforcing steel do not exceed 90 percent of the reinforcing steel yield.
(2) Maximum concrete compressive stresses do not exceed 85 percent of the concrete design compressive strength.

8.4.14.12.2 If the conditions in 8.4.14.12.1 are not met, the prior damage shall be taken into account in the spill analysis.

8.4.14.13 Instrumentation capable of measuring the ground motion to which tank systems are subjected shall be provided on the site.

8.4.15 Testing of LNG Containers.

Δ **8.4.15.1** The LNG primary container shall be hydrostatically tested and leak tested in accordance with the governing construction code or standard and all leaks shall be repaired.

8.4.15.2 The tank system designer shall provide a test procedure based on the applicable construction standard.

8.4.15.3* Membrane containment tank systems shall be tested in accordance with EN 14620, *Design and manufacture of site built, vertical, cylindrical, flat-bottomed, steel tanks for the storage of refrigerated, liquefied gases with operating temperatures between 0°C and −165°C*, Part 5, Table 1, as follows:

(1) The leakage test, as defined in the Note under EN 14620, Part 5, paragraph 4.1.1, shall be performed.
(2) Leakage through the membrane to the insulation space during service shall be controlled in order to maintain a gas concentration level below 30 percent of the lower explosive limit (LEL) by sweeping the insulated space with an inert gas.
(3) If the gas concentration cannot be maintained below 30 percent of the LEL, the tank shall be decommissioned and retested.
(4) For purposes of evaluating the 30 percent level, the flow of purge gas within the annular space shall not be increased above the normal operating rate.

8.4.15.4 Verification of all components of the membrane containment tank system design by experimental data from model tests shall be carried out.

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8.4.16 Additional Requirements for Membrane Containment Tank Systems.

Δ **8.4.16.1** A thermal corner protection system functionally equivalent to the thermal corner protection system for concrete containers, as defined in Section 6 of API Std 625, *Tank Systems for Refrigerated Liquefied Gas Storage*, and if required by ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases*, shall be provided for the outer concrete container of the membrane tank system where the concrete-to-base slab joint cannot maintain liquid tightness under the spill condition.

N **8.4.16.1.1 Thermal Corner Protection.**

N **8.4.16.1.1.1** The thermal corner protection shall protect the entire bottom of the outer container and at least the lower 16.5 ft (5 m) of the wall necessary thermally isolate from the cold liquid and provide liquid tightness at the monolithic or pinned wall-to-slab junction.

N **8.4.16.1.1.2** The thermal corner protection shall be liquid-tight where in contact with LNG.

Δ **8.4.16.1.2** The thermal corner protection system shall be permitted to be either metallic or made from nonmetallic materials compatible with LNG and shall maintain structural integrity and liquid tightness under all applicable mechanical and thermal loads.

8.4.16.1.3 Tests.

N **8.4.16.1.3.1** The membrane containment tank system supplier shall provide tests independently witnessed and verified by a third-party agency clearly demonstrating the liquid leak-tightness of all the thermal corner protection system under spill conditions.

N **8.4.16.1.3.2** Historical tests shall be acceptable provided that construction processes and materials of construction are the same as those proposed.

8.4.16.1.4 Nondestructive examination (NDE) performed on the secondary barrier and NDE acceptance criteria shall ensure that the provided liquid tightness is equivalent to the liquid tightness provided by the metallic thermal corner protection system of the full containment tank system.

• **8.4.16.2** The outer concrete container of the membrane containment tank system shall meet all requirements of ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases*, for the secondary concrete container, including materials, design, construction, inspection, and testing and the additional requirements specified in 8.4.16.2.1 through 8.4.16.2.5.

8.4.16.2.1 Liquid Product Pressure.

N **8.4.16.2.1.1** The pressure of the liquid product shall be a design load for the outer concrete container.

N **8.4.16.2.1.2** The liquid product pressure ultimate limit state (ULS) load factors for operating and abnormal loading conditions shall be in accordance with Table 7.2 of ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases.*

8.4.16.2.2 Concrete Container Wall.

N **8.4.16.2.2.1** The outer concrete container wall and slab-to-wall junction shall be checked for fatigue assuming a minimum of four full load-unload cycles a week for the expected life of the tank system.

N **8.4.16.2.2.2** Performance criteria of Appendix C of ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases*, shall apply.

8.4.16.2.3 The outer concrete container wall shall resist the specified impact load without perforation and scabbing.

Δ **8.4.16.2.3.1** The concrete wall thickness shall be at least 40 percent greater than the scabbing depth calculated per Section 4.1.2.2 of CEB 187, *Concrete Structures Under Impact and Impulsive Loading — Synthesis Report.*

Δ **8.4.16.2.3.2** The concrete wall thickness shall be at least 20 percent greater than the perforation thickness calculated per Section 4.1.1.1 of CEB 187, *Concrete Structures Under Impact and Impulsive Loading — Synthesis Report.*

Δ **8.4.16.2.3.3** The concrete wall shall be designed so that either one of the following conditions is satisfied:

(1) The distance between the outer face of the concrete container and the centroid of the pre-stressing tendons is greater than the penetration depth calculated per Section 4.1.2.1 of CEB 187, *Concrete Structures Under Impact and Impulsive Loading — Synthesis Report*, with the following allowances for uncertainty:
   (a) 20 percent thicker than the penetration depth where $z > 0.75$
   (b) 50 percent thicker than the penetration depth where $z \le 0.75$
(2) The concrete wall is designed to be able to resist normal operating loads with any one horizontal tendon completely ineffective.

8.4.16.2.3.4 For concrete walls post-tensioned with a wire wrapping system, the wall shall be designed to resist normal operating loads with the wires affected by a specified impact load considered completely ineffective. No unwrapping of the post-tensioning wires shall be allowed.

8.4.16.2.4 At a minimum, the outer concrete container for the membrane tank system shall meet the construction tolerances specified in ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases.* Where more stringent tolerances are required by the membrane and insulation systems, those more stringent tolerances shall be specified by the membrane tank engineer and met by the tank contractor.

8.4.16.2.5 The outer concrete container shall be hydrotested prior to membrane and insulation installation following the primary container hydrotest requirements of API Std 625, *Tank Systems for Refrigerated Liquefied Gas Storage*, Section 10.

8.5 ASME Containers.

8.5.1 General.

8.5.1.1 ASME containers used for the storage of LNG shall be either of the following:

(1) Double-walled, with the inner container holding the LNG surrounded by insulation contained in the outer container as specified in 8.5.1.3 and 8.5.1.4
(2) Single-walled, if designed and fabricated according to the criteria that is specified in 8.5.1.5

8.5.1.2 The insulation shall be evacuated or purged.

8.5.1.3 The inner container shall be of welded construction and in accordance with Section VIII of the ASME *Boiler and Pressure Vessel Code* and shall be ASME-stamped and registered with the National Board of Boiler and Pressure Vessel Inspectors or other agencies that register pressure vessels.

Δ **8.5.1.3.1** Where vacuum is utilized for insulation purposes, the design pressure of the inner container shall be the sum of the required working pressure (absolute) and the hydrostatic head of LNG.

8.5.1.3.2 Where vacuum is not utilized as part of the insulation, the design pressure shall be the sum of the required working gauge pressure and the hydrostatic head of LNG.

8.5.1.3.3 The inner container shall be designed for the most critical combination of loading resulting from internal pressure and liquid head, the static insulation pressure, the insulation pressure as the container expands after an in-service period, the purging and operating pressure of the space between the inner and outer containers, and seismic loads.

N **8.5.1.3.4** The inner vessel relief devices shall be sized in accordance with 8.4.10.5 or with CGA S-1.3, *Pressure Relief Device Standards — Part 3 — Stationary Storage Containers for Compressed Gases.*

8.5.1.4 The outer container shall be of welded construction.

Δ **8.5.1.4.1** The following materials shall be used:

(1) Any of the carbon steels in Section VIII, Part UCS of the ASME *Boiler and Pressure Vessel Code* at temperatures at or above the minimum allowable use temperature in Section II, Part D, Table 1A of the ASME *Boiler and Pressure Vessel Code*
(2) Materials with a melting point below 2000°F (1093°C) where the container is buried or mounded

Δ **8.5.1.4.2** Where vacuum is utilized for insulation purposes, the outer container shall be designed by either of the following:

(1) Section VIII, Parts UG-28, UG-29, UG-30, and UG-33 of the ASME *Boiler and Pressure Vessel Code*, using an external pressure of not less than 15 psi (103 kPa)
(2) Paragraph 3.6.2 of CGA 341, *Standard for Insulated Cargo Tank Specification for Cryogenic Liquids*

Δ **8.5.1.4.3** Heads and spherical outer containers that are formed in segments and assembled by welding shall be designed in accordance with Section VIII, Parts UG-28, UG-29, UG-30, and UG-33, of the ASME *Boiler and Pressure Vessel Code*, using an external pressure of 15 psi (103 kPa).

8.5.1.4.4 The maximum allowable working pressure shall be specified for all components.

8.5.1.4.5 The outer container shall be equipped with a relief device or other device to release internal pressure, as follows:

(1) The discharge area shall be at least 0.00024 in.^{2}/lb (0.34 mm^2/kg) of the water capacity of the inner container, but the area of any individual device shall not exceed 300 in.^{2} (0.2 m^2).
(2) The relief device shall function at a pressure not exceeding the internal design pressure of the outer container, the external design pressure of the inner container, or 25 psi (172 kPa), whichever is least.

8.5.1.4.6 Thermal barriers shall be provided to prevent the outer container from falling below its design temperature.

8.5.1.4.7 Saddles and legs shall be designed to withstand loads anticipated during shipping and installation, and seismic, wind, and thermal loads.

8.5.1.4.8 Foundations and supports shall be protected to have a fire resistance rating of at least 2 hours.

8.5.1.4.9 If insulation is used to achieve the fire resistance rating of at least 2 hours, it shall be resistant to dislodgment by fire hose streams.

N **8.5.1.5** The single-walled container shall be of welded construction and in accordance with Section VIII, Division 1 of the ASME *Boiler and Pressure Vessel Code* and shall be ASME-stamped and registered with the National Board of Boiler and Pressure Vessel Inspectors or other agencies that register pressure vessels

N **8.5.1.5.1 Single-Walled Container Construction and Material.**

N **8.5.1.5.1.1** Material shall conform to ASME *Boiler and Pressure Vessel Code,* Section II, SA553, Type I, subject to the additional supplementary requirement S56, but with a minimum impact test value of 66 ft·lbf (90 J).

N **8.5.1.5.1.2** Material shall be approved by a third party for the type (chemical composition, impact resistance, tensile strength, yield strength, ductility, drop weight test), grade, and dimension of steel supplied.

N **8.5.1.5.2** The minimum wall thickness along the maximum allowable liquid level of the container shall be the greater of the following:

(1) A wall thickness defined by a design pressure of not less than the maximum allowable relief valve setting (MARVS)
(2) A wall thickness defined by a design liquid pressure P_{eq} in a full container, resulting from the design vapor pressure P_0 and the liquid pressure as given by equation 8.5.1.5.2a

Δ **[8.5.1.5.2a]**

$$P_{eq} = P_o + P_{gd}$$

with

Δ **[8.5.1.5.2b]**

$$P_0 = 2 + A \cdot C \cdot \rho^{1.5}(\text{barg})$$

[8.5.1.5.2c]

$$A = 0.0185\left(\frac{\sigma_m}{\Delta\sigma_a}\right)^2$$

where:
σ_m = Design primary membrane stress, to be taken as the smallest of $^{\sigma}B/3.5$ or $^{\sigma}F/1.5$
σ_B = Specified minimum ultimate tensile strength at room temperature (N/mm^2)
σ_F = Specified minimum upper yield stress at room temperature (N/mm^2)
$\Delta\sigma_a$ = Allowable dynamic membrane stress (double amplitude at probability level 10^{-8})
= 55 N/mm^2 for ferritic-perlitic, martensitic, and austenitic steels
C = Characteristic tank dimension, taken as the greatest of the following: h, $0.75 \cdot b$, or $0.45 \cdot l$
h = Height of tank exclusive dome (m)
b = Width of tank (m)
l = Length of tank (m)
ρ = Maximum cargo specific gravity
and

[8.5.1.5.2d]

$$P_{gd} = (1 \cdot 10^{-2}) \cdot z \cdot g \cdot \rho(\text{barg})$$

where:
z = Vertical distance to maximum liquid level (m)
g = Gravity (m/s^2)
ρ = Maximum cargo specific gravity

(3) A minimum wall thickness of 0.65 in. (16.51 mm) at the maximum allowable liquid level

N **8.5.1.5.3** The container shall be equipped with a relief device or other device to release internal pressure, as follows:

(1) The discharge area shall be at least 0.00024 in.^{2}/lb (0.34 mm^2/kg) of the water capacity of the container, but the area of any individual device shall not exceed 300 in.^{2} (0.2 m^2).
(2) The relief device shall function at a pressure not exceeding the internal design pressure of the outer container, the external design pressure of the inner container, or 25 psi (172 kPa), whichever is least.

N **8.5.1.5.4** Saddles and legs shall be designed to withstand loads anticipated during shipping and installation, and seismic, wind, and thermal loads.

N **8.5.1.5.5** Foundations and supports shall be protected to have a fire resistance rating of at least 2 hours.

N **8.5.1.5.6** If insulation is used to achieve the fire resistance rating of at least 2 hours, it shall be resistant to dislodgment by fire hose streams.

N **8.5.1.5.7** All container penetrations shall be located above the maximum allowable liquid level.

N **8.5.1.5.8** The minimum amount of nondestructive testing and welding production testing to be carried out shall be specifically as follows:

(1) One-hundred percent radiography shall be required for all butt-welds, or automatic ultrasonic testing (AUT) shall be accepted as a replacement of radiographic testing, as defined in ASME *Boiler and Pressure Vessel Code,* Section VIII, Division 2, 7.5.5.
(2) The following additional welding production tests for each 164 ft (50 m) of butt-weld joints shall be performed:
    (a) Charpy Impact Test in accordance with UG-84 within ASME *Boiler and Pressure Vessel Code,* Section VIII, Division 1
    (b) Transverse weld tensile tests in accordance with QW-150 of ASME *Boiler and Pressure Vessel Code,* Section IX
    (c) Transverse Guided Bend Test in accordance with QW-160 within ASME *Boiler and Pressure Vessel Code,* Section IX
(3) Longitudinal bend tests shall be required in lieu of transverse bend tests in cases where the base material and weld material have different strength levels.

N **8.5.1.5.9 Impoundment.**

N **8.5.1.5.9.1** Chapter 13 shall not apply when determining impoundment requirements.

N **8.5.1.5.9.2** A risk assessment shall be performed as per Chapter 19, to define the site specific external risk and identify requirements for increased minimum wall thickness or impoundment for plant siting.

8.5.1.6 Stress concentrations from the support system shall be minimized by the use of such items as pads and load rings.

8.5.1.7 The expansion and contraction of the inner container shall be included in the stress calculations, and the support system shall be designed so that the resulting stresses imparted to the inner and outer containers are within allowable limits.

8.5.1.8 Internal piping between the inner container and the outer container and within the insulation space shall be designed for the maximum allowable working pressure of the inner container, with allowance for thermal stresses.

8.5.1.8.1 Bellows shall not be permitted within the insulation space.

8.5.1.8.2 Piping shall be of materials satisfactory for −278°F (−172°C) as determined by the ASME *Boiler and Pressure Vessel Code.*

8.5.1.8.3 No liquid line external to the outer container shall be of aluminum, copper, or copper alloy, unless it is protected against a 2-hour fire exposure.

8.5.1.8.4 Transition joints shall not be prohibited.

8.5.1.9 The inner container shall be supported concentrically within the outer container by either a metallic or a nonmetallic system that is capable of sustaining the maximum loading of either of the following:

(1) Shipping load supports shall be designed for the maximum acceleration to be encountered, multiplied by the empty mass of the inner container.
(2) Operating load supports shall be designed for the total mass of the inner container plus the maximum loading, which shall include the following:
    (a) Seismic factors shall be included.
    (b) The mass of contained liquid shall be based on the maximum density of the specified liquid within the range of operating temperatures, except that the minimum density shall be 29.3 lb/ft^3 (470 kg/m^3).

8.5.1.10 The allowable design stress in support members shall be the lesser of one-third of the specified minimum tensile strength or five-eighths of the specified minimum yield strength at room temperature. Where threaded members are used, the minimum area at the root of the threads shall be used.

8.5.1.11 Piping that is a part of an ASME LNG container, including piping between the inner and outer containers, shall be in accordance with either Section VIII of the ASME *Boiler and Pressure Vessel Code* or ASME B31.3, *Process Piping.*

Δ **8.5.1.12** Compliance of piping which is part of the ASME container shall be stated on or appended to Appendix W, Form U-1, "Manufacturer's Data Report for Pressure Vessels," of the ASME *Boiler and Pressure Vessel Code.*

8.5.2 Seismic Design of Land-Based Shop-Built ASME Containers.

8.5.2.1 Shop-built containers designed and constructed in accordance with the ASME *Boiler and Pressure Vessel Code* and their support system shall be designed for the dynamic forces associated with horizontal and vertical accelerations as follows:

For horizontal force, *V*:

[8.5.2.1a]

$$V = Z_c \times W$$

For design vertical force, P:

[8.5.2.1b]

$$P = \frac{2}{3} Z_c \times W$$

where:

Z_c = seismic coefficient equal to 0.60 S_{DS}, where S_{DS} is the maximum design spectral acceleration determined in accordance with the provisions of ASCE 7, *Minimum Design Loads and Associated Criteria for Buildings and Other Structures*, using an importance factor, I, of 1.0, for the site class most representative of the subsurface conditions where the LNG facility is located

W = total weight of the container and its contents

8.5.2.1.1 This method of design shall be used only when the natural period, T, of the shop-built container and its supporting system is less than 0.06 seconds.

8.5.2.1.2 For periods of vibration greater than 0.06 seconds, the method of design in 8.4.14 shall be followed.

8.5.2.2 The container and its supports shall be designed for the resultant seismic forces in combination with the operating loads, using the allowable stress increase shown in the code or standard used to design the container or its supports.

8.5.2.3 The requirements of 8.5.2 shall apply to ASME containers built prior to July 1, 1996, when reinstalled.

8.5.2.4 Instrumentation capable of measuring the ground motion to which containers are subjected shall be provided on the site.

8.5.3 Filling Volume. Containers designed to operate at a pressure in excess of 15 psi (103 kPa) shall be equipped with a device(s) that prevents the container from becoming liquid-full or from covering the inlet of the relief device(s) with liquid when the pressure in the container reaches the set pressure of the relieving device(s) under all conditions.

8.5.4 Testing of ASME LNG Containers.

8.5.4.1 ASME containers designed for gauge pressures in excess of 15 psi (103 kPa) shall be tested in accordance with the following:

(1) Shop-fabricated containers shall be pressure tested by the manufacturer prior to shipment to the installation site.
(2) The inner container shall be tested in accordance with the ASME *Boiler and Pressure Vessel Code* or with CSA B51, *Boiler, Pressure Vessel and Pressure Piping Code*.
(3) The outer container shall be leak tested.
(4) Piping shall be tested in accordance with Section 10.8.
(5) Containers and associated piping shall be leak tested prior to filling the container with LNG.

8.5.4.2 The inner container of field-fabricated containers designed for gauge pressures in excess of 15 psi (103 kPa) shall be tested in accordance with the ASME *Boiler and Pressure Vessel Code* or CSA B51, *Boiler, Pressure Vessel and Pressure Piping Code*.

8.5.4.3 The outer container of field-fabricated containers designed for gauge pressures in excess of 15 psi (103 kPa) shall be tested in accordance with the ASME *Boiler and Pressure Vessel Code* or CSA B51, *Boiler, Pressure Vessel and Pressure Piping Code*.

N **8.5.5 Shipment of LNG Containers.** Containers shall be shipped under a minimum internal pressure of 10 psi (69 kPa) inert gas.

Chapter 9 Vaporization Facilities

9.1* Scope. This chapter presents the design, construction, and installation requirements for LNG vaporizers.

9.2 Classification of Vaporizers.

9.2.1 If the temperature of the naturally occurring heat source of an ambient vaporizer exceeds 212°F (100°C), the vaporizer shall be considered to be a remote heated vaporizer.

9.2.2 If the naturally occurring heat source of an ambient vaporizer is separated from the actual vaporizing heat exchanger and a controllable heat transport medium is used between the heat source and the vaporizing exchanger, the vaporizer shall be considered to be a remote heated vaporizer and the provision for heated vaporizers shall apply.

9.3 Design and Materials of Construction.

Δ **9.3.1*** Vaporizers shall be designed, fabricated, and inspected in accordance with Section VIII of the ASME *Boiler and Pressure Vessel Code*.

9.3.2 Vaporizer heat exchangers shall be designed for a working pressure at least equal to the maximum discharge pressure of the LNG pump or the pressurized container system supplying them, whichever is greater.

9.3.3 The discharge valve of each vaporizer and the piping components between the vaporizer and the valve, including relief valves installed upstream of each vaporizer discharge valve, shall be designed for operation at LNG temperatures [−260°F (−162°C)].

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9.4 Vaporizer Shutoff Valves.

N **9.4.1** At least one manual or automatic shutoff valve shall be installed on the LNG inlet to a vaporizer or vaporizer system that shall be closed in any one of the following situations:

(1) Loss of line pressure (i.e., excess flow)
(2) Fire in the immediate vicinity of the vaporizer or shutoff valve
(3) Temperature above or below the design temperature of the vaporizer system, including the vaporizer discharge line

N **9.4.1.1** Where LNG plants are either unattended or vaporizers are installed within a 50 ft (15 m) radius of their heat source or any flammable liquids container, an automatic shutoff valve shall be installed within 10 ft (3 m) of the vaporizer or vaporizer system in accordance with 16.3.5.

N **9.4.1.2** Where an LNG plant is attended and vaporizers are installed at least a 50 ft (15 m) radius from their heat source and any flammable liquids container, either an automatic or manual shutoff valve shall be installed at least a 50 ft (15 m) radius form the vaporizer, vaporizer system, or vaporizer building.

N **9.4.2** The manual or automatic shutoff valve in the LNG inlet to the vaporizer or vaporizer system shall have the capability of being either locally or remotely actuated.

N **9.4.3** The manual or automatic shutoff valve shall be independent of all other flow control systems.

N **9.4.4** Where a flammable intermediate fluid is used with a vaporizer, shutoff valves shall be provided on both the hot and the cold lines of the intermediate fluid system with the controls at least a 50 ft (15 m) radius from the vaporizer.

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9.5 Relief Devices on Vaporizers.

9.5.1 The relief valve capacity of heated or process vaporizers shall be selected to provide discharge capacity of 110 percent of rated vaporizer natural gas flow capacity without allowing the pressure to rise more than 10 percent above the vaporizer maximum allowable working pressure.

9.5.2 The relief valve capacity for ambient vaporizers shall be selected to provide relief valve discharge capacity of at least 150 percent of rated vaporizer natural gas flow capacity based on standard operating conditions, without allowing the pressure to rise more than 10 percent above the vaporizer maximum allowable working pressure.

9.5.3 Relief valves on heated vaporizers shall be located so that they are not subjected to temperatures exceeding 140°F (60°C) during normal operation unless the valves are designed to withstand higher temperatures.

9.6 Combustion Air Supply. Combustion air required for the operation of integral heated vaporizers or the primary heat source for remote heated vaporizers shall be taken from outside a completely enclosed structure or building.

9.7 Products of Combustion. Where integral heated vaporizers or the primary heat source for remote heated vaporizers are installed in buildings, provisions shall be made to prevent the accumulation of hazardous products of combustion within the building.

Chapter 10 Piping Systems and Components

10.1* Scope. This chapter presents the design, construction, installation, examination, and inspection requirements for process piping systems and components.

10.2 General.

10.2.1* Process piping that is a part of an ASME LNG container, including piping between the inner and outer containers, shall be in accordance with either Section VIII of the ASME *Boiler and Pressure Vessel Code*, or ASME B31.3, *Process Piping*. All other process piping shall meet ASME B31.3.

10.2.1.1 The additional provisions of this chapter supplement those in ASME B31.3, *Process Piping*, and shall apply to piping systems and components for hazardous fluid service.

10.2.1.2 Fuel gas systems shall be in accordance with ANSI Z223.1/NFPA 54 or ASME B31.3, *Process Piping*.

Δ **10.2.1.3** Fire protection system piping shall meet the applicable NFPA standards in Section 2.2.

N **10.2.1.4** Power plant piping shall be in accordance with ASME B31.1, *Power Plant Piping*.

10.2.2 Seismic Design Requirements.

10.2.2.1 Piping design shall be in accordance with the following requirements in addition to those in Section 12.1:

(1) Classification A piping per Section 12.1 — For the OBE design, response modifications shall not be used.
(2) Classification B piping per Section 12.1 — At maximum, a response modification factor R_p of 3 shall be used. The importance value I_p shall be taken as 1.5.
(3) Classification C piping per Section 12.1 — Piping shall be designed for the design earthquake per ASCE 7, *Minimum Design Loads and Associated Criteria for Buildings and Other Structures*.

10.2.2.2 Piping shall be analyzed using an equivalent static analysis or a dynamic analysis meeting the requirements of ASCE 7, *Minimum Design Loads and Associated Criteria for Buildings and Other Structures*. The OBE, SSE, and design earthquake loads shall be combined with other loads using the load combination of ASCE 7. The stiffness of pipe supports in the direction of applied restraint shall be included in the pipe stress analysis model unless the supports can be qualified as rigid according to the following criteria:

(1) Supports with 12 in. (0.3 m) and larger pipe: minimum support stiffness of 100 kips/in. (1797 kg/mm) in the direction of restraint
(2) Supports with 12 in. (0.3 m) and smaller pipe: minimum support stiffness of 10 kips/in. (179.7 kg/mm) in the direction of restraint

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10.2.3* Piping systems and components shall be designed to accommodate the effects of fatigue resulting from the thermal cycling to which the systems are subjected.

10.2.4 Provision for expansion and contraction of piping and piping joints due to temperature changes shall be in accordance with Section 319 of ASME B31.3, *Process Piping*.

10.3 Materials of Construction.

10.3.1 General.

10.3.1.1 All piping materials, including gaskets and thread compounds, shall be selected for compatibility with the liquids and gases handled throughout the range of temperatures to which they are subjected.

10.3.1.2 Piping, including gasketed joints, that can be exposed to the low temperature of an LNG or refrigerant release or the heat of an ignited release during an emergency where such exposure could result in a failure of the piping that would increase the emergency shall be one of the following:

(1) Made of material(s) that can withstand both the normal operating temperature and the extreme temperature to which the piping might be subjected during the emergency
(2) Protected by insulation or other means to delay failure due to such extreme temperatures until corrective action can be taken by the operator
(3) Capable of being isolated and having the flow stopped where piping is exposed only to the heat of an ignited release during the emergency

10.3.1.3 Piping insulation used in areas where the mitigation of fire exposure is necessary shall have a maximum flame spread index of 25 when tested in accordance with ASTM E84, *Standard Test Method for Surface Burning Characteristics of Building*

Materials, or ANSI/UL 723, *Standard for Test for Surface Burning Characteristics of Building Materials,* and shall maintain those properties that are necessary to maintain physical and thermal integrity during an emergency when exposed to fire, heat, cold, or water.

10.3.1.4* In addition to 10.3.1.3, pipe insulation assemblies used in areas where the mitigation of fire exposure is necessary shall be one of the following:

(1) Comprised of noncombustible materials per ASTM E136, *Standard Test Method for Behavior of Materials in a Vertical Tube Furnace at 750°C(see Section 4.10)*
(2) Covered by an outer protective stainless steel jacket at least 0.02 in. (0.51 mm) thick
(3) Covered by an outer aluminum jacket at least 0.032 in. (0.81 mm) thick
(4) Determined to meet the conditions of acceptance in B.3 of NFPA 274

10.3.2 Piping.

10.3.2.1 Type F piping, spiral welded piping, furnace lap-welded pipe and furnace butt-welded pipe shall not be used.

Δ **10.3.2.2** All piping material shall either meet the requirements in Chapter III of ASME B31.3, *Process Piping,* or conform with paragraphs 323.1.2 and 323.2.3 of ASME B31.3, and be documented in the engineering design.

Δ **10.3.2.3** All piping components shall either meet the requirements in Chapter III of ASME B31.3, *Process Piping,* or conform with paragraphs 326.1.2 and 326.2.2 of ASME B31.3, and be documented in the engineering design.

10.3.2.4 Threaded pipe shall be at least Schedule 80.

Δ **10.3.2.5** A liquid line on a container, cold box, or other insulated equipment external to the outer shell or jacket, whose failure can release a significant quantity of flammable fluid, shall not be made of aluminum, copper or copper alloy, or material with a melting point of less than 2000°F (1093°C).

10.3.2.5.1 Bottom penetration liquid lines on single containment tanks with aluminum inner tanks and cold boxes utilizing aluminum heat exchangers shall be permitted to use aluminum piping to the point where the thermal distance piece transitions to stainless steel or other materials meeting the requirements of 10.3.2.5.

10.3.2.6 Transition Joints.

10.3.2.6.1 Transition joints shall be protected against fire exposure. Thermal distance pieces from containers, coldboxes, and similar equipment shall not be insulated if insulation will diminish the effectiveness of the thermal distance piece.

10.3.2.6.2 Protection against fire exposure shall not be required for liquid lines protected against fire exposure and loading arms and hoses.

10.3.2.7 Cast iron, malleable iron, and ductile iron pipe shall not be used for hazardous fluids.

10.3.3 Fittings.

10.3.3.1 Threaded nipples shall be at least Schedule 80.

10.3.3.2 Cast iron, malleable iron, and ductile iron fittings shall not be used for hazardous fluids.

10.3.3.3* **Bends.**

10.3.3.3.1 Bends shall be permitted only in accordance with Section 332 of ASME B31.3, *Process Piping*. Corrugated and creased bends shall be prohibited.

Δ **10.3.3.3.2** Field bending shall not be permitted on any 300 series stainless steel or other cryogenic containment materials or components, except instrument tubing with a minimum design temperature less than −20°F (−29°C) unless:

(1) Performed in accordance with the engineering design
(2) Performed using mechanical or hydraulic equipment and tools specifically designed for bending pipe
(3) The examination requirements of paragraphs 332.1 and 332.2.1 in ASME B31.3, *Process Piping,* are used to verify each bend
(4) All bending and forming of piping material shall meet the requirements of Section 332 in ASME B31.3, except that corrugated and creased bends shall be prohibited

10.3.3.4 Solid plugs or bull plugs made of at least Schedule 80 seamless pipe shall be used for threaded plugs.

10.3.3.5 Compression-type couplings shall not be used where they can be subjected to temperatures below −20°F (−29°C), unless they meet the requirements of Section 315 of ASME B31.3, *Process Piping*.

10.3.4 Valves.

10.3.4.1 Valves shall comply with one of the following:

(1) Paragraph 307.1.1 of ASME B31.3, *Process Piping*
(2) ASME B31.5, *Refrigeration Piping and Heat Transfer Components*; ASME B31.8, *Gas Transmission and Distribution Piping Systems*; or API Spec 6D, *Specification for Pipeline and Piping Valves,* where suitable for the design conditions
(3) Paragraph 307.1.2 of ASME B31.3, where documented in the engineering design

10.3.4.2 Cast iron, malleable iron, and ductile iron valves shall not be used.

10.4 Installation.

10.4.1 Piping Joints.

10.4.1.1 Pipe joints of 2 in. (50 mm) nominal diameter or less shall be threaded, welded, or flanged.

10.4.1.2 Pipe joints larger than 2 in. (50 mm) nominal diameter shall be welded or flanged.

10.4.1.3 Tubing joints shall be in accordance with paragraph 315 in ASME B31.3, *Process Piping*.

10.4.1.4 The following pipe joints are prohibited:

(1) Expanded joints per paragraph 313 of ASME B31.3, *Process Piping*
(2) Caulked joints per paragraph 316 of ASME B31.3
(3) Special joints per paragraph 318 of ASME B31.3

Δ **10.4.1.5** Special components that are unlisted per paragraph 304.7.2 of ASME B31.3, *Process Piping,* shall be based on design calculations consistent with the design criteria of ASME B31.3. Calculations shall be substantiated by at least one of the two means stated in paragraph 304.7.2 (a) or 304.7.2(b) of ASME B31.3.

10.4.1.6 Where necessary for connections to equipment or components, where the connection is not subject to fatigue-producing stresses, joints of 4 in. (100 mm) nominal diameter or less shall be threaded, welded, or flanged.

10.4.1.7 The number of threaded or flanged joints shall be minimized and used only where necessary, such as at material transitions or instrument connections, or where required for maintenance.

N **10.4.1.8 Flanged Connections.**

N **10.4.1.8.1** Where utilized, flanged connections shall be in accordance with Section 335 of ASME B31.3 *Process Piping*.

N **10.4.1.8.2** Where spring washers or similar methods are used to achieve and maintain clamping forces during temperature transitions, the bolt, nut, and washer assembly shall be installed appropriately for the size of the bolt, within the acceptable stress levels of the specific bolt and any specific installation instructions from the spring washer manufacturer or similar device manufacturer.

10.4.1.9 Where threaded joints are used, they shall be seal welded or sealed by other means proven by test except for the following:

(1) Instrument connections where the heat from welding would cause damage to the instrument
(2) Where seal welding would prevent access for maintenance
(3) Material transitions where seal welding is not practical
(4) A piping system with a minimum design temperature greater than or equal to −20°F (−29°C)

10.4.1.10 Dissimilar metals shall be joined by flanges or transition joint techniques that have been proven by test at the intended service conditions.

10.4.1.11 Where gaskets are subject to fire exposure, they shall be resistant to fire exposure.

10.4.2* Valves.

10.4.2.1 Extended bonnet valves shall be installed with packing seals in a position that prevents leakage or malfunction due to freezing.

10.4.2.2 Where the extended bonnet in a cryogenic liquid line is installed at an angle greater than 45 degrees from the upright vertical position, it shall be demonstrated to be free of leakage and frost under operating conditions.

Δ **10.4.2.3** Shutoff valves shall be installed on container, tank, and vessel connections, except for the following:

(1) Connections for relief valves that are not managed in accordance with Section VIII, UG-125(d) and Appendix M-5 of the ASME *Boiler and Pressure Vessel Code*
(2) Connections to liquid lines of ½ in. (12.5 mm) or less pipe size and vapor lines of 2 in. (50 mm) or less pipe size
(3) Connections that are blind flanged or plugged

10.4.2.4 Shutoff valves shall be located inside the impoundment area as close as practical to such containers, tanks, and vessels where provided.

10.4.2.5 The design and installation of an internal valve shall be such that any failure of the penetrating nozzle resulting from external pipe strain is beyond the shutoff seats of the internal valve itself.

Δ **10.4.2.6** In addition to the container shutoff valve required in 10.4.2.3, container connections larger than ½ in. (12.5 mm) nominal diameter and through which liquid can escape shall be equipped with at least one of the following:

(1)* A valve that closes automatically if exposed to fire
(2) A remotely controlled, quick-closing valve that remains closed except during the operating period
(3) A check valve on filling connections

N **10.4.2.7** Temperature-sensitive elements of emergency shutoff valves shall not be painted, nor shall they have any ornamental finishes applied after manufacture.

10.4.2.8 Valves and valve controls shall be designed to allow operation under icing conditions where such conditions can exist.

10.4.2.9 Powered and manual operators shall be provided for emergency shutoff valves 8 in. (200 mm) or larger.

10.4.2.10* Where power-operated valves are installed, the closure time shall not produce a hydraulic shock capable of causing stresses that can result in piping or equipment failure.

10.4.2.11 A piping system used for periodic transfer of cold fluid shall be provided with a means for precooling before transfer.

10.4.2.12 Check valves shall be installed in designated one-directional transfer systems to prevent backflow and shall be located as close as practical to the point of connection to any system from which backflow might occur.

10.4.3 Welding and Brazing. All pressure containment, ASME B31.3, *Process Piping*, piping, and component welding and brazing in or for any LNG facility shall be in accordance to Section IX of the ASME *Boiler and Pressure Vessel Code*.

10.4.3.1 Qualification and performance of welders shall be in accordance with subsection 328.2 of ASME B31.3, *Process Piping*, and 10.4.3.2 of this standard.

10.4.3.2 For the welding of impact-tested materials, qualified welding procedures shall be selected to minimize degradation of the low-temperature properties of the pipe material.

10.4.3.3 For the welding of attachments to unusually thin pipe, procedures and techniques shall be selected to minimize the danger of burn-through.

10.4.3.4 Oxygen–fuel gas welding shall not be permitted.

10.4.3.5 Brazing and brazed connections shall be in accordance with subsections 317.2 and 333 of ASME B31.3, *Process Piping*.

Δ **10.4.3.6** Brazed connections which are part of an ASME B31.3, *Process Piping*, piping system shall be limited to a minimum service temperature of −20°F (−29°C) and warmer. The system shall be in accordance with Appendix G of ASME B31.3. Brazed connections used for service temperatures colder than −20°F (−29°C) shall be specified in the engineering design and approved by the operator.

10.4.4* Pipe Marking. Markings on pipe shall comply with the following:

(1) Markings shall be made with a material compatible with the pipe material.

(2) Materials less than ¼ in. (6.4 mm) in thickness shall not be die stamped.
(3) Marking materials that are corrosive to the pipe material shall not be used.
(4) Markings shall be in accordance with the specification to which the specific pipe is manufactured.

N **10.5 Isolation of Hazardous Fluid Equipment and Systems.**

N **10.5.1** The design for isolating equipment, systems, or piping in hazardous fluid service for maintenance, routine idle operation, or seasonal shutdowns shall consider the properties and operating pressure of the hazardous fluid.

N **10.5.2** Where any leakage of hazardous fluid through a primary isolation device, such as a valve, can generate a safety or operational hazard, a second isolation device shall be used.

N **10.5.2.1*** A means to safely and continuously vent or drain the space between the first and second isolation devices shall be provided.

N **10.5.2.2** A check valve shall not be used as an isolation device.

10.6 Pipe Supports.

10.6.1* Pipe supports, including any insulation systems used to support pipe whose stability is essential to plant safety, shall be resistant to or protected against fire exposure, escaping cold liquid, or both, if they are subject to such exposure. Fire protection for such piping supports shall be designed in accordance with recognized standards.

10.6.2 Pipe supports for cold lines shall be designed to minimize heat transfer, which can result in piping failure by ice formations or embrittlement of supporting steel.

10.6.3 The design of supporting elements shall conform to Section 321 of ASME B31.3, *Process Piping*.

10.7* Piping Identification.

N **10.7.1** Piping shall be identified by color coding, painting, or labeling.

N **10.7.2** Labeling of pipe shall indicate service and normal flow direction(s).

10.8 Inspection, Examination, and Testing of Piping. Inspection, examination, and testing shall be performed in accordance with Chapter VI of ASME B31.3, *Process Piping*, to demonstrate sound construction, installation and leak tightness. Unless specified otherwise in the engineering design, piping systems for flammable liquids and flammable gases shall be examined and tested per the requirements of ASME B31.3.

10.8.1 Leak Testing.

10.8.1.1 Leak testing shall be conducted in accordance with Section 345 of ASME B31.3, *Process Piping*.

10.8.1.2 To avoid possible brittle failure, carbon and low-alloy steel piping shall be leak tested at metal temperatures suitably above their nil ductility transition temperature.

10.8.2 Record Keeping.

10.8.2.1 A record of each leak test shall be made per paragraph 345.2.7 of ASME B31.3, *Process Piping*.

10.8.3 Welded Pipe Examinations.

10.8.3.1 The longitudinal or spiral weld of longitudinal welded pipe that is subjected to minimum design temperatures below −20°F (−29°C) shall be subjected to 100 percent radiographic examination in accordance with paragraph 302.3.4 and Table A-1B of ASME B31.3, *Process Piping*, to provide a basic longitudinal weld joint Quality Factor E_j of 1.0 or as allowed in Table 302.3.4 for E_j equal to 1.0.

Δ **10.8.3.2** All circumferential butt groove welds, miter bend groove welds, and branch connection welds comparable to Figure 328.5.4E in ASME B31.3, *Process Piping*, subjected to minimum design temperatures below −20°F (−29°C) shall be examined fully by radiographic or ultrasonic examination in accordance with Chapter VI, Sections 341 and 344, of ASME B31.3, except as modified by 10.8.3.2.1 and 10.8.3.2.2.

10.8.3.2.1 Liquid drain and vapor vent piping with an operating pressure that produces a hoop stress of less than 20 percent specified minimum yield stress shall not be required to be nondestructively tested if it has been inspected visually in accordance with subsection 344.2 of ASME B31.3, *Process Piping*.

10.8.3.2.2 Piping with minimum design temperature at or above −20°F (−29°C) shall have random 20 percent radiographic or ultrasonic examination of circumferential butt groove welds, miter bend groove welds, and branch connection welds comparable to Figure 328.5.4E in ASME B31.3, *Process Piping*, in accordance with Chapter VI, Sections 341 and 344, of ASME B31.3.

10.8.3.3 All socket welds and fillet welds, for piping with a design minimum temperature below −20°F (−29°C), including internal and external attachment welds, shall be 100 percent examined visually and by liquid penetrant or magnetic particle examination in accordance with Chapter VI, Sections 341 and 344, of ASME B31.3, *Process Piping*.

Δ **10.8.3.4*** All branch connection welds not radiographed or ultrasonically examined, shall be 100 percent examined per Chapter VI, Sections 341 and 344, of ASME B31.3, *Process Piping*. as follows:

(1) For piping with design temperatures below −20°F (−29°C), all branch connections shall be 100 percent visually examined and by liquid penetrant or magnetic particle examination.
(2) For piping with design temperatures at or above −20°F (−29°C), all branch connections shall be 100 percent visually examined.

10.8.4 Examination Criteria.

Δ **10.8.4.1** Nondestructive examination methods, limitations on defects, and the qualifications of the personnel performing and interpreting the examinations shall meet the requirements of Chapter VI, Sections 341 through 344, of ASME B31.3, *Process Piping*, and the following:

(1) The requirements of Normal Fluid Service shall apply as a minimum for examination acceptance criteria, unless specified otherwise in the engineering design.
(2) Personnel performing nondestructive examinations (NDE) shall, as a minimum, be qualified Level I per ASNT SNT-TC-1A, *Personnel Qualification and Certification in Nondestructive Testing*, or an equivalent qualification standard.

(3) Personnel interpreting nondestructive examinations shall, as a minimum, be qualified Level II per ASNT SNT-TC-1A or an equivalent qualification standard.
(4) NDEs shall be performed in accordance with written procedures meeting all the requirements of Section V of the ASME *Boiler and Pressure Vessel Code*, as applicable to the specific NDE method.

10.8.4.2 Substitution of in-process examination for radiographic or ultrasonic examination as permitted in Paragraph 341.4.1 of ASME B31.3, *Process Piping*, shall be permitted on a weld-for-weld basis only if specified in the engineering design, specifically approved by the operator, and supplemented by the following additional nondestructive examinations:

(1) 100 percent liquid penetrant or magnetic particle examination shall be performed at the lesser of one-half the weld thickness or each ½ in. (12.5 mm) of weld thickness.
(2) 100 percent liquid penetrant or magnetic particle examination shall be performed on all accessible final weld surfaces.

10.8.5 Record Retention.

Δ **10.8.5.1** Test and examination records and written procedures required within this standard and within Paragraph 345.2.7 and Section 346, respectively, of ASME B31.3, *Process Piping*, shall be maintained for the life of the piping system by the facility operator or until such time as a re-examination is conducted.

10.8.5.2 Records and certification pertaining to materials, components, and heat treatment as required by Paragraphs 341.4.1(c) and 341.4.3(d), and Section 346 of ASME B31.3, *Process Piping*, shall be maintained by the facility operator for the life of the system.

10.9 Purging of Piping Systems.

10.9.1 Blow-down and purge connections shall be provided to facilitate purging of all process piping and all flammable gas piping.

N **10.9.2** Purge connections shall also be provided on either side of piping line block valves if the valves are anticipated to be closed during purge to avoid unpurged dead leg piping.

10.10 Safety and Relief Valves.

10.10.1 Pressure-relieving safety devices shall be arranged so that the possibility of damage to piping or appurtenances is reduced to a minimum.

Δ **10.10.1.1*** Safety relief systems (i.e., piping and valves) shall be designed, installed, and tested in accordance with subsection 322.6 of ASME B31.3, *Process Piping*, recognized standards, and Section 10.10 of this standard.

10.10.2 The means for adjusting relief valve set pressure shall be sealed.

10.10.3 A thermal expansion relief valve shall be installed to prevent overpressure in any section of a liquid or cold vapor pipeline that can be isolated by valves.

10.10.3.1 A thermal expansion relief valve shall be set to discharge at or below the design pressure of the line it protects.

10.10.3.2 Discharge from thermal expansion relief valves shall be directed to minimize hazard to personnel and other equipment.

N **10.11* Flares and Vent Stacks.** Flares and vent stacks shall be designed in accordance with recognized standards and shall limit flammable vapors at or above the LFL from reaching grade and radiant heat of no more than 5 kW/m² from reaching unrestricted areas or any adjacent equipment or occupied buildings.

10.12 Corrosion Control.

10.12.1* Underground and submerged piping shall be protected and maintained in accordance with the principles of NACE SP 0169, *Control of External Corrosion of Underground or Submerged Metallic Piping Systems.*

10.12.2 Austenitic stainless steels and aluminum alloys shall be protected to minimize corrosion and pitting from corrosive atmospheric and industrial substances during storage, construction, fabrication, testing, and service.

10.12.2.1 Tapes or other packaging materials that are corrosive to the pipe or piping components shall not be used.

10.12.2.2 Where insulation materials can cause corrosion of aluminum or stainless steels, inhibitors or waterproof barriers shall be utilized.

10.13 Cryogenic Pipe-in-Pipe Systems.

10.13.1 General. The design of cryogenic pipe shall address the following issues:

(1) Seismic loading, geotechnical concerns, installation, and the concern that the pipe be designed to perform its function without failure in accordance with 10.2.2
(2) Dynamic loading and static loading conditions of both the inner and outer pipes
(3) Maximum relative motion between the inner and outer pipes

10.13.2 Inner Pipe.

N **10.13.2.1** The inner pipe assembly shall be designed, fabricated, examined, and tested in accordance with ASME B31.3, *Process Piping*, and inspection levels shall be specified.

N **10.13.2.2** As a minimum, Normal Fluid Service requirements shall be met, unless specified otherwise in the engineering design.

N **10.13.2.3** Toxic fluids shall be Category M.

10.13.3 Outer Pipe. The outer pipe assembly shall be designed, fabricated, examined, and tested in accordance with the requirements of ASME B31.3, *Process Piping*. Alternative methods for leak testing the outer pipe and visually inspecting the inner pipe during leak tests shall be approved.

10.13.3.1 As a minimum, Normal Fluid Service requirements shall be met, unless specified otherwise in the engineering design.

10.13.3.2 If the outer pipe also functions as the secondary containment system, the following shall apply:

(1) The outer pipe shall be designed to contain the inner pipe product upon any release from the inner pipe.
(2) The outer pipe shall be designed, fabricated, examined, and tested in accordance with the requirements of ASME B31.3, *Process Piping*.

(3) The outer pipe shall include a stress analysis of the mechanical forces and thermal shock upon a release from the inner pipe.

N **10.13.3.3** Design of the inner pipe support spacer shall demonstrate that deformation of the outer pipe will not cause the spacer to puncture the inner pipe.

10.13.4 Vacuum-Jacketed Function. Vacuum-jacketed systems shall demonstrate that failure of the vacuum-jacketed system would not affect the integrity of the inner pipe.

10.13.4.1 If the outer jacket functions as the secondary containment system, the outer pipe jacket shall be designed to withstand any release from the inner pipe and shall be designed, fabricated, examined, and tested in accordance with the requirements of ASME B31.3, *Process Piping*.

10.13.5 Annular Space. The annular space and inner pipe support system shall be designed to minimize thermal conductance and heat loss.

10.13.5.1 All components in the annular space shall be selected to minimize long-term degradation of the insulation system.

10.13.5.2 The vacuum level, if any, shall be specified.

10.13.6 Operational Requirements.

10.13.6.1 If the pipe-in-pipe is vacuum-jacketed, provisions shall be made to allow verification of vacuum levels and methods of reapplication of vacuum. If the pipe-in-pipe is not vacuum-jacketed, provision shall be made to allow circulation of inert gas in the annulus.

10.13.6.2 Provisions shall be made for temperature monitoring.

(A) Where the pipe-in-pipe is a vacuum-jacketed pipe, the temperature of the outer skin of the vacuum jacket shall be monitored.

(B) Where the pipe-in-pipe is not vacuum jacketed, the temperature in the annulus shall be monitored.

(C) Visual inspection shall be acceptable for aboveground installations.

10.13.7 Connections. Mechanical connectors shall be designed to maintain the thermal, structural, and installation conditions present on the pipe segments it is connecting.

10.13.8* Corrosion Protection.

10.13.8.1 The inner pipe and the annular space shall be considered to be noncorroding in its operating environment.

10.13.8.2 The outer pipe shall be designed or protected in accordance with NACE standards to mitigate potential corrosion.

10.14 Below-Ground or Subsea Installation.

10.14.1* Pipe, when buried on land, shall be installed with a minimum of 3 ft. (0.9 m) of cover and meet recognized standards.

10.14.2* Pipe, when buried in navigable waterways, shall be installed with a minimum depth of 4 ft. (1.2 m) of cover and meet recognized standards.

N **10.14.3** Depth of cover shall be measured to the top of the outer pipe or casing.

10.14.4 The engineering design of buried pipe in navigable waters shall evaluate, and, where necessary, implement additional cover to minimize the possibility of damage due to anchor drop or drag and ship grounding events.

N **10.14.5** Where pipe is installed inside a casing, the casing pipe shall meet the following requirements:

(1) The casing shall be designed to withstand the superimposed loads.
(2) If there is a possibility of water entering the casing, the ends shall be sealed.
(3) If vents are installed on a casing, the vents shall be protected from the weather to prevent water from entering the casing.
(4) If the ends of an unvented casing are sealed, then the sealing shall be strong enough to retain the maximum allowable working pressure of the pipe.
(5) Each pipeline shall be electrically isolated from metallic casings that are a part of the underground system. If isolation is not achieved because it is impractical, other measures shall be taken to minimize corrosion of the pipeline inside the casing.

Chapter 11 Instrumentation and Electrical Services

11.1 Scope. This chapter covers the requirements for instrumentation, controls, and electrical systems for the LNG facility.

N **11.2* General.** Instrumentation shall be included to control the process within the safe operating range and alarm or shutdown facilities in the event of excursions beyond the safe operating range. Instrumentation shall be specified and provided in accordance with recognized standards.

11.3 Liquid Level Gauging.

11.3.1 LNG Containers.

Δ **11.3.1.1** LNG containers shall be equipped with liquid level gauging devices as follows:

(1) Containers smaller than 1000 gal (3.8 m^3) shall be equipped with either a fixed length dip tube or other level devices.
(2) Containers of 1000 gal (3.8 m^3) through 30,000 gal (113.5 m^3) shall have a minimum of one liquid level device that provides a continuous level indication ranging from full to empty.
(3) Containers larger than 30,000 gal (113.5 m^3) shall have two independent devices that compensate for variations in liquid density.

11.3.1.2 Gauging devices on containers of 1000 gal (3.8 m^3) or larger shall be designed and installed so that they can be replaced without taking the container out of operation.

11.3.1.3 Each container greater than 30,000 gal (113.5 m^3) shall be provided with two independent high-liquid-level alarms for containers, which shall be permitted to be part of the liquid level gauging devices.

11.3.1.3.1* The alarm shall be set so that the operator can stop the flow without exceeding the maximum permitted filling height and shall be located so that they are audible and visible to personnel controlling the filling.

11.3.1.3.2 The high-liquid-level flow cutoff device required in 11.3.1.4 shall not be considered as a substitute for the alarm.

11.3.1.4 The LNG container shall be equipped with a high-liquid-level flow cutoff device, which shall be separate from all gauges.

11.3.2* Tanks for Refrigerants or Flammable Process Fluids.

11.3.2.1 Each storage tank shall be equipped with two independent liquid level gauging devices.

11.3.2.2 If it is possible to overfill the tank, a high-liquid-level alarm shall be provided in accordance with 11.3.1.3.

11.3.2.3 The requirements of 11.3.1.4 shall apply to installations of refrigerants or flammable process fluids.

11.4 Pressure Gauging.

N **11.4.1** Each LNG container shall be equipped with a minimum of two independent pressure gauging devices connected to the container at a point above the maximum intended liquid level for continuous monitoring and high- and low-pressure alarms.

N **11.4.2** Each non-LNG hazardous fluid container shall be equipped with a pressure gauge connected to the container at a point above the maximum intended liquid level for continuous monitoring and high- and low-pressure alarms.

11.5 Vacuum Gauging. Vacuum-jacketed components shall be equipped with instruments or connections for checking the absolute pressure in the annular space.

11.6 Temperature Indicators. Temperature-monitoring devices shall be provided in field-erected containers to assist in controlling temperatures when the container is placed into service or as a method of checking and calibrating liquid level gauges.

11.6.1 Where the potential risk of damage to piping and components downstream of heat exchangers exists due to temperature limitations, indication shall be provided to monitor outlet temperatures.

11.6.2 Temperature-monitoring and alarm systems shall be provided where foundations supporting cryogenic containers and equipment could be affected adversely by freezing or frost heaving of the ground.

N **11.6.3** Temperature-monitoring and alarm systems shall be provided where underground cryogenic piping could cause and be adversely affected by freezing or frost heaving of the ground.

N **11.7 Control Systems.**

N **11.7.1*** Control centers required by 18.6.1, process control systems, and safety instrumented systems, shall be designed, engineered, installed, and documented in accordance with recognized standards.

N **11.7.2*** A cybersecurity vulnerability assessment of the process control systems and safety instrumented systems shall be conducted and reviewed every 2 years not to exceed 27 months or at intervals determined by the AHJ, and revised as necessary.

11.8 Fail-Safe Design. Instrumentation and control devices shall be designed so that, in the event that power or instrument air failure occurs, the system will proceed to a fail-safe condition that is maintained until the operators can take action either to reactivate or to secure the system.

11.9 Electrical Equipment.

11.9.1* Electrical equipment and wiring shall be in accordance with *NFPA 70* or CSA C22.1, *Canadian Electrical Code*.

Δ **11.9.2*** Fixed electrical equipment and wiring installed within the classified areas specified in Table 11.9.2 shall comply with Table 11.9.2 and Figure 11.9.2(a) through Figure 11.9.2(e) and shall be installed in accordance with *NFPA 70*.

11.9.3* Electrically classified areas shall be as specified in Table 11.9.2 and as specified by recognized methods that account for the properties of the fluids potentially released such as highly volatile liquids (HVLs) and the conditions of the fluids such as operating pressure, density, temperature, and volume.

N **11.9.3.1** High pressures, potentially large releases, and the presence of HVLs shall be evaluated to determine if greater dimensions for classified locations than those shown in Table 11.9.2 are required.

11.9.3.2 The extent of the electrically classified area shall not extend beyond an unpierced wall, roof, or solid vaportight partition.

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11.9.4 When electrical equipment is installed with enclosures residing in electrically classified areas per 11.9.2, the enclosures either shall be rated for that area classification or shall be in accordance with NFPA 496.

11.9.5 The interior of an LNG container shall not be a classified area where the following conditions are met:

(1) Electrical equipment is de-energized and locked out until the container is purged of air.
(2) Electrical equipment is de-energized and locked out prior to allowing air into the container.
(3) The electrical system is designed and operated to de-energize the equipment automatically when the pressure in the container is reduced to atmospheric pressure.

11.9.6* Each interface between a flammable fluid system and an electrical conduit or wiring system, including process instrumentation connections, integral valve operators, foundation heating coils, canned pumps, and blowers, shall be sealed or isolated to prevent the passage of flammable fluids to another portion of the electrical installation in accordance with the requirements in this standard, Article 501.17 of *NFPA 70*, and ISA 12.27.01, *Requirements for Process Sealing Between Electrical Systems and Flammable or Combustible Process Fluids*.

11.9.6.1 Each seal, barrier, or other means used to comply with 11.9.6 shall be designed to prevent the passage of flammable fluids through the conduit, stranded conductors, and cables.

11.9.6.2 A primary seal shall be provided between the flammable fluid system and the electrical conduit wiring system.

Δ Table 11.9.2 Electrical Area Classification

Part	Location	Group D, Division[a]	Extent of Classified Area
A	**LNG storage containers with vacuum breakers**		
	Inside containers	2	Entire container interior, except where 11.9.5 applies
B	**LNG storage container area**		
	Indoors	1	Entire room
	Outdoor aboveground containers (other than small containers)[b]	1	Open area between a high-type dike and the container wall where dike wall height exceeds distance between dike and container walls *[see Figure 11.9.2(b)]*
		2	Within 15 ft (4.5 m) in all directions from container walls and roof plus area inside a low-type diked or impounding area up to the height of the dike impoundment wall *[see Figure 11.9.2(a)]*
	Outdoor belowground containers	1	Within any open space between container walls and surrounding grade or dike *[see Figure 11.9.2(c).]*
		2	Within 15 ft (4.5 m) in all directions from roof and sides *[see Figure 11.9.2(c).]*
C	**Tank car, tank vehicle, and container loading and unloading**		
	Indoors with adequate ventilation[c]	1	Within 5 ft (1.5 m) in all directions from connections regularly made or disconnected for product transfer
		2	Beyond 5 ft (1.5 m) and entire room and 15 ft (4.5 m) beyond any wall or roof ventilation discharge vent or louver
	Outdoors in open air at or above grade	1	Within 5 ft (1.5 m) in all directions from connections regularly made or disconnected for product transfer
		2	Beyond 5 ft (1.5 m) but within 15 ft (4.5 m) in all directions from a point where connections are regularly made or disconnected and within the cylindrical volume between the horizontal equator of the sphere and grade
D	**Electrical seals and vents specified in 10.7.5 through 10.7.7**	2	Within 15 ft (4.5 m) in all directions from the equipment and within the cylindrical volume between the horizontal equator of the sphere and grade
E	**Marine terminal loading and unloading areas** *[see Figure 11.9.2(e).]*	2	Within 15 ft (4.5 m) in all directions, above the deck, from the open sump

[a]See Article 500 in *NFPA 70* for definitions of classes, groups, and divisions. Article 505 can be used as an alternate to Article 500 for classification of hazardous areas using an equivalent zone classification to the division classifications specified in Table 11.9.2. Most of the flammable vapors and gases found within the facilities covered by NFPA 59A are classified as Group D. Ethylene is classified as Group C. Much of the available electrical equipment for hazardous locations is suitable for both groups.
[b]Small containers are portable and of less than 200 gal (760 L) capacity.
[c]Ventilation is considered adequate where provided in accordance with the provisions of this standard.

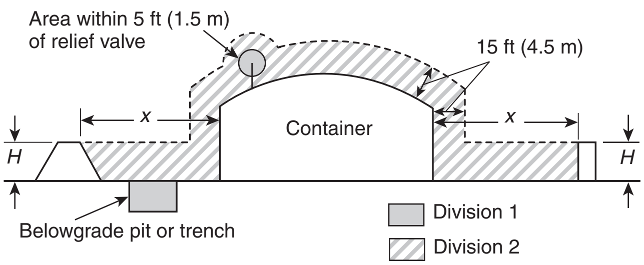


FIGURE 11.9.2(a) Dike Height Less Than Distance from Container to Dike (*H* < *x*).

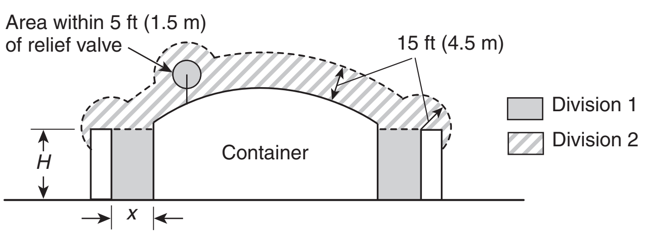


FIGURE 11.9.2(b) Dike Height Greater Than Distance from Container to Dike (*H* > *x*).

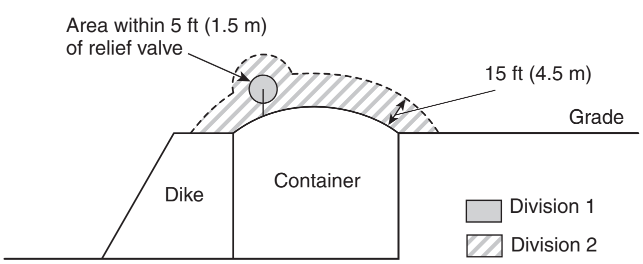
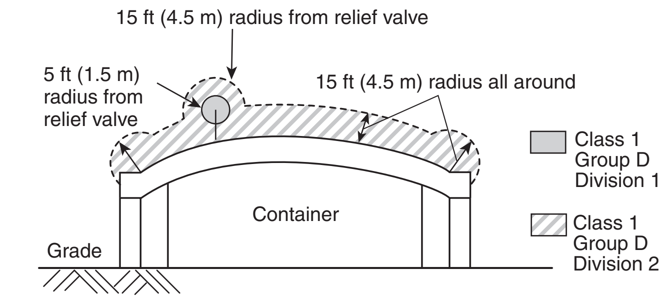


FIGURE 11.9.2(c) Container with Liquid Level Below Grade or Below Top of Dike.

11.9.6.2.1 If the failure of the primary seal allows the passage of flammable fluids to another portion of the conduit or wiring system, an additional approved seal, barrier, or other means shall be provided to prevent the passage of the flammable fluid beyond the additional device or means if the primary seal fails.

11.9.6.2.2 Each primary seal shall be designed to withstand the service conditions to which it can be exposed.

11.9.6.2.3 Each additional seal or barrier and interconnecting enclosure shall be designed to meet the pressure and temperature requirements of the condition to which it could be exposed in the event of failure of the primary seal unless other approved means are provided to accomplish the purpose.



Δ FIGURE 11.9.2(d) Full and Membrane Containment Tank Systems.

11.9.6.3 Secondary Seal.

11.9.6.3.1 Where secondary seals are used, the space between the primary and secondary seals shall be continuously vented to the atmosphere.

11.9.6.3.2 Similar provisions to 11.9.6.3.1 shall be made on double-integrity primary sealant systems of the type used for submerged motor pumps.

11.9.6.3.3 The requirements of 11.9.6.3.1 shall apply to double-integrity primary sealant systems.

N **11.9.6.3.4** Where a padded system is used between the primary and secondary seal and does not have a means of venting, a physical interruption of the conduit run and of the stranded conductors shall be installed and vented downstream of the seals.

11.9.6.4 The seals specified in 11.9.6 and 11.9.7 shall not be used to meet the conduit sealing requirements of*NFPA 70* or CSA C22.1, *Canadian Electrical Code*.

11.9.7 Where primary seals are installed, drains, vents, or other devices shall be provided to detect flammable fluids and leakage.

11.9.8 The venting of a conduit system shall minimize the possibility of damage to personnel and equipment if a flammable gas–air mixture is ignited.

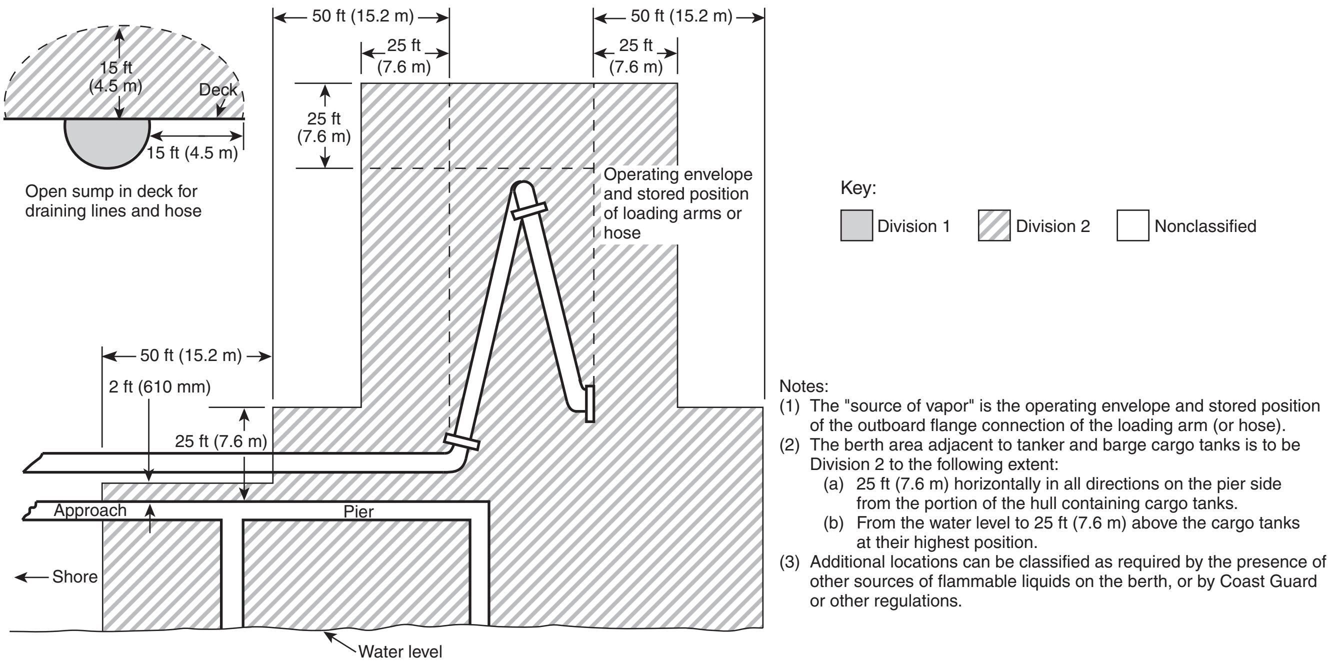
11.10 Electrical Grounding and Bonding.

11.10.1* General. Electrical grounding and bonding shall be provided.

11.10.2 Bonding shall not be required at transfer areas where both halves of metallic hose couplings or pipe are in contact.

11.10.3* If stray currents can be present or if impressed currents are used on loading and unloading systems (such as for cathodic protection), protective measures to prevent ignition shall be taken.

11.10.4* A lightning protection system shall be provided for storage containers supported on nonconductive foundations.



Δ **FIGURE 11.9.2(e) Classification of a Marine Terminal Handling LNG.**

N Chapter 12 Plant Facilities Design

N **12.1 Design Classification.** Buildings, structures, and systems, including equipment and piping, shall be classified in accordance with the following:

(1)* *Classification A*: LNG tank systems, buildings, structures, and systems, including equipment and piping, as defined in 8.4.14.6(3)

(2) *Classification B*: Buildings, enclosures, and structures, including the main control room, supporting containers other than LNG tank systems, equipment, and piping, that contain hazardous fluids, as well as containers other than LNG tank systems, equipment, and piping that contain hazardous fluids that are not in a building

(3) *Classification C*: All other buildings, equipment, piping, and structures

N **12.2 Plant Facilities Design.** Buildings, equipment, piping, and structures shall be designed for seismic activity including tsunami, wind, ice, flood including hurricane storm surge, and snow in accordance with 12.2.1 through 12.2.3.

N **12.2.1* Classification A.**

N **12.2.1.1** Seismic design shall use the operating basis earthquake (OBE), safe shutdown earthquake (SSE), and aftershock level earthquake (ALE) ground motions as defined in 8.4.14.3 through 8.4.14.5. Structures, equipment, and piping shall be designed for the OBE without response reductions for inelastic behavior. Structures, equipment and piping shall also be designed for the SSE and ALE and are permitted to be designed for the SSE and ALE with response reductions for inelastic behavior provided such reductions are justified and such inelastic behavior does not impair the safety function of the item.

N **12.2.1.2** Tsunami, wind, ice, flood including hurricane storm surge and snow hazard levels, design loads, and associated criteria shall be determined per ASCE 7, *Minimum Design Loads and Associated Criteria for Buildings and Other Structures* based on a risk category of IV per ASCE 7 and the additional requirements of this standard.

N **12.2.2 Classification B.** Seismic, tsunami, wind, ice, flood including hurricane storm surge, and snow hazard levels, design loads, and associated criteria shall be determined per ASCE 7, *Minimum Design Loads and Associated Criteria for Buildings and Other Structures*, based on a risk category of III per ASCE 7 and the additional requirements of this standard.

N **12.2.3 Classification C.** Seismic, tsunami, wind, ice, flood including hurricane storm surge, and snow hazard levels, design loads, and associated criteria per ASCE 7, *Minimum Design Loads and Associated Criteria for Buildings and Other Structures*, based on a risk category of II per ASCE 7.

N **12.3 Seismic Design.** Additional seismic design requirements for piping shall be in accordance with 10.2.2.

N **12.4 LNG Containers.** Design requirements for LNG containers shall be in accordance with Chapter 8.

N **12.5 Buildings or Structural Enclosures.** Buildings or structural enclosures in which LNG, flammable refrigerants, and flammable gases are handled shall be of lightweight, noncombustible construction with non-load-bearing walls.

N **12.6 Fire and Explosion Control.** Rooms containing LNG and flammable fluids, if located within or attached to buildings in which such fluids are not handled (e.g., control centers, shops), shall be designed for fire and explosion control in accordance with the following:

(1) Deflagration venting shall be provided in accordance with NFPA 68.

(2) Common walls shall have no doors or other communicating openings.

(3) Common walls shall have a fire-resistance rating of at least 1 hour.

N **12.7 Ventilation.** Buildings or structural enclosures in which LNG, flammable refrigerants, and flammable gases are handled shall be ventilated to minimize the possibility of hazardous accumulations of flammable gases or vapors, in accordance with 12.7.1 through 12.7.4.

N **12.7.1** Ventilation shall be permitted to be by means of one of the following:

(1) A continuously operating mechanical ventilation system
(2) A combination gravity ventilation system and normally nonoperating mechanical ventilation system that is energized by combustible gas detectors in the event combustible gas is detected
(3) A dual-rate mechanical ventilation system with the high rate energized by gas detectors in the event flammable gas is detected
(4) A gravity ventilation system composed of a combination of wall openings and roof ventilators
(5) Other approved ventilation systems

N **12.7.2** If there are basements or depressed floor levels, a supplemental mechanical ventilation system shall be provided.

N **12.7.3** The ventilation rate shall be at least 1 cfm of air per ft^2 (5 L/sec of air per m^2) of floor area.

N **12.7.4** If vapors heavier than air can be present, a portion of the ventilation shall be from the lowest level exposed to such vapors.

N **12.8 Flammable Gas or Vapor Control.** Buildings or structural enclosures not covered by Sections 12.5 through 12.7 shall be located, or provisions otherwise shall be made, to minimize the possibility of entry of flammable gases or vapors.

N **12.9* Occupant Protection.** Buildings or structural enclosures not covered by Sections 12.5 through 12.7 shall be designed, constructed, and installed to protect occupants against explosion, fire, and toxic material releases.

N Chapter 13 Impounding Area and Drainage System Design and Capacity

N **13.1 Single Container Impounding Areas.** Impounding areas serving one LNG container shall have a minimum volumetric holding capacity, *V*, that is one of the following:

(1) *V* = 110 percent of the maximum liquid capacity of the container
(2) *V* = 100 percent where the impoundment is designed to withstand the dynamic surge in the event of catastrophic failure of the container
(3) *V* = 100 percent where the height of the impoundment is equal to or greater than the container maximum liquid level

N **13.2 Multiple Container Impounding Areas.** Impounding areas serving multiple LNG containers shall have a minimum volumetric holding capacity, *V*, in accordance with one of the following:

(1) *V* = 100 percent of the maximum liquid capacity of all containers in the impoundment area
(2) *V* = 110 percent of the maximum liquid capacity of the largest container in the impoundment area, where provisions are made to prevent leakage from any container due to exposure to a fire, low temperature, or both due to a leak from or fire on any other container in the shared impoundment

N **13.2.1*** The volumetric capacity calculations for impounding areas shall account for equipment within the impounding area that could impact capacity.

N **13.3 Other Impounding Areas.** Impounding areas other than those serving LNG storage shall have a minimum volumetric holding capacity equal to the volume of liquid that can accumulate on the ground from a release from the greater of the following:

(1) The largest container or pressure vessel served by the impounding area
(2) The largest flow in any piping served by that impounding area for a 10-minute spill duration, or a shorter time based on demonstrable surveillance and shutdown provisions acceptable to the authority having jurisdiction or if the inventory will be depleted in less than 10 minutes

N **13.4 Enclosed Drainage Channels.** Enclosed drainage channels for LNG or other flammable and combustible liquids shall be prohibited except where they meet one of the following requirements:

(1) Where enclosed drainage channels are approved to be used to rapidly conduct spilled LNG or other flammable and combustible liquids away from critical areas and they are sized for the anticipated liquid flow and vapor formation rates
(2) Where the enclosed drainage channels are inerted or purged with an inert gas and continuously monitored for a flammable liquid leak or flammable gas, and instrumentation and controls are provided to maintain pressures at a safe level within the drainage channel
(3) Where the enclosed drainage channels are provided with deflagration venting in accordance with NFPA 68
(4) Where pipe-in-pipe is installed in accordance with 10.13.3.2, and instrumentation and controls are provided to maintain pressures at a safe level within the drainage channel

N **13.5 Enclosed Impounding Systems.** Enclosed impounding systems for piping shall be prohibited except for where they meet one of the following conditions:

(1) The system is sealed from the atmosphere, filled with an inert gas, and instrumentation and controls are provided to maintain pressures at a safe level and to monitor gas concentrations.
(2) Pipe-in-pipe is installed in accordance with 10.13.3.2.

N **13.5.1** Flammable nonmetallic membranous covering shall be prohibited in an enclosed system.

N **13.5.2** Enclosed impounding systems shall have adequate structural strength to withstand the external loads that could cause a failure of the impounding system.

N **13.6* Dikes and Impounding Walls.** Dikes and impounding walls shall meet the following requirements:

(1) Dikes, impounding walls, drainage systems, and any penetrations thereof shall be designed to withstand the full hydrostatic head of impounded LNG and other hazardous liquids, the effect of rapid cooling to the temperature of the liquid to be confined, any anticipated fire expo-

sure, and natural forces, such as earthquakes, wind, and rain.

(2) Where the outer container of a tank system complies with the requirements of 5.3.1.1 and 5.3.1.2, the dike shall be either the outer container or as specified in 5.3.1.1 and 5.3.1.2.

N **13.7 Secondary Containment.** Double containment tank systems shall be designed and constructed such that in the case of a spill and secondary container fire, the secondary container wall will contain the LNG for the duration of the fire.

N **13.8 Pipe Penetrations.** Double, full, and membrane containment tank systems shall have no pipe penetrations below the liquid level.

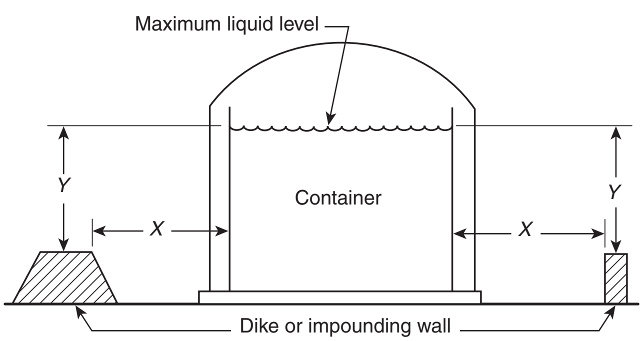
N **13.9 Dikes, Impounding Walls, and Drainage Channels.**

N **13.9.1** Dikes, impounding walls, and drainage channels for flammable or combustible liquid containment shall conform to NFPA 30.

N **13.9.2** Dikes, impounding walls, and drainage channels for liquefied gas containment shall conform to NFPA 58, NFPA 59, and API Std 2510, *Design and Construction of Liquefied Petroleum Gas (LPG) Installations*, as applicable.

N **13.10 Insulation Systems.** Insulation systems used for impounding surfaces shall be, in the installed condition, noncombustible and suitable for the intended service, considering the anticipated thermal and mechanical stresses and loads. If flotation of the insulation can compromise its intended purpose, mitigating measures shall be provided.

N **13.11 Impounding Area Wall Height and Distance to Containers.** The dike or impounding wall height and the distance from containers designed for less than 15 psi (103 kPa) shall be determined in accordance with Figure 13.11.



Notes:
- *X* is the distance from the inner wall of the container to the closest face of the dike or impounding wall.
- *Y* is the distance from the maximum liquid level in the container to the top of the dike or impounding wall.
- *X* equals or exceeds the sum of *Y* plus the equivalent head in LNG of the pressure in the vapor space above the liquid.

Exception: When the height of the dike or impounding wall is equal to or greater than the maximum liquid level, X has any value.

N **FIGURE 13.11 Dike or Impoundment Wall Proximity to Containers.**

N **13.12 Water Removal.**

N **13.12.1** Impounding areas shall be provided with water removal systems capable of removing water at a minimum of 25 percent of the rate from a storm of a 10-year frequency and 1-hour duration, except if the design of the impounding area does not allow the entrance of rainfall.

N **13.12.2** Water removal systems shall be as follows:

(1) Operated as necessary to keep the impounding area as dry as practical
(2) If designed for automatic operation, have redundant automatic shutdown controls to prevent operation when LNG or other hazardous fluids are present
(3) If water removal systems are designed for manual operation, have a means or procedure to prevent hazardous fluids from escaping through piping or valves

N Chapter 14 Mobile and Temporary LNG Facility

N **14.1 Temporary Service Use.** Where mobile and temporary LNG equipment is used for temporary use, for service maintenance during gas systems repair or alteration, or for other short-term applications, the following requirements shall be met:

(1) Mobile and temporary LNG equipment shall not remain in service more than 180 days at the mobile and temporary equipment installation. Mobile and temporary installations in service more than 180 days shall meet one of the following:
   (a) Approval by the AHJ to remain for a period exceeding 180 days
   (b) Compliance with all the applicable requirements of Chapter 17 for stationary applications using ASME containers and with the security requirements in Section 16.8
(2) LNG transport vehicles complying with U.S. Department of Transportation (DOT) requirements shall be used as the supply container.
(3) All mobile and temporary LNG equipment shall be operated by at least one person qualified by experience and training in the safe operation of these systems in accordance with the requirements in 18.11.3 and 18.11.4, based on the written training plan requirements in 18.11.1 and 18.11.2.
(4) All other operating personnel, at a minimum, shall be qualified by training in accordance with the requirements in 18.11.3 and 18.11.4, based on the written training plan requirements in 18.11.1 and 18.11.2.
(5) All personnel requiring training in 14.1(2) and 14.1(3) shall receive refresher training in accordance with requirements in 18.11.6.1.
(6) All personnel training shall be documented in accordance with records requirements in 18.12.4.
(7) Each operator shall provide and implement a written plan of initial training in accordance with the requirements in 18.11.1 and 18.11.2 to instruct all designated operating and supervisory personnel.
(8) Provisions shall be made to minimize the possibility of accidental discharge of LNG at containers endangering adjoining property or important process equipment and structures or reaching surface water drainage.
(9) Mobile and temporary containment means shall be permitted to be used.

(10) Vaporizers and controls shall comply with Section 9.3, 9.4.1(1), 9.4.1(2), and Section 9.5.
(11) Each heated vaporizer shall be provided with a means to shut off the fuel source remotely and at the installed location.
(12) Equipment and process design, including piping, piping components, instrumentation and electrical systems, and transfer systems, shall comply with Sections 4.2 and 4.9; 7.3.3, 7.3.5, 7.3.6, 7.3.7, 7.5.1, 7.5.2, 7.5.6.1, 7.5.6.2, 10.2.1, 10.2.1.1, 10.2.1.2, 10.3.1.1, 10.3.1.2(3), 10.3.2.1 through 10.3.2.4, 10.3.3, and 10.3.4; Sections 10.4 through 10.10; and if utilized, cryogenic pipe-in-pipe systems shall comply with Section 10.13, 11.9.1, 11.9.2, 11.9.6, 11.10.1, 15.4.1, 15.6.1, 15.6.2, 15.8.1, 15.8.2, 15.8.3, 15.8.6, 15.9.1, 15.9.2, and 16.2.1.
(13) The LNG facility spacing specified in Table 6.3.1 shall be maintained except where necessary to provide temporary service on a public right-of-way or on property where clearances specified in Table 6.3.1 are not feasible and where the following additional requirements are met:
    (a) Traffic barriers shall be erected on all sides of the facility subject to passing vehicular traffic.
    (b) The operation shall be continuously attended to monitor the operation whenever LNG is present at the facility.
    (c) If the facility or the operation causes any restriction to the normal flow of vehicular traffic, in addition to the monitoring personnel required in 14.1(10), flag persons shall be continuously on duty to direct such traffic.
(14) Provisions shall be made to minimize the possibility of accidental ignition in the event of a leak.
(15) Fire protection systems shall comply with 16.2.1, Section 16.3, 16.4.1, 16.4.2.2, 16.6.1, 16.7.1, 16.8.1, and 16.8.2.
(16) Portable or wheeled fire extinguishers recommended by their manufacturer for gas fires shall be available at strategic locations and shall be provided and maintained in accordance with NFPA 10.
(17) Operating and maintenance activities shall comply with Sections 16.4.2 and 18.1 through 18.4; 18.8.1, 18.8.2, 18.8.4, 18.8.5, 18.8.6.5 through 18.8.6.8, 18.8.6.8.3, 18.8.6.8.4, 18.8.6.8.5; Section 18.9; and 18.10.1, 18.10.2, 18.10.6, 18.10.8, 18.10.9, 18.10.10.1, 18.10.10.2, 18.10.10.3, 18.10.10.7, 18.10.13.1, 18.10.13.6, and 18.10.13.7.
(18) The site shall be continuously attended, and provisions shall be made to restrict public access to the site whenever LNG is present.

N **14.2 Odorization Equipment.** If odorization is required of the temporary facility, the restrictions of 6.3.1 shall not apply to the location of odorizing equipment containing 20 gal (76 L) or less of flammable odorant within the retention system.

Chapter 15 Transfer Systems for LNG and Other Hazardous Fluids

15.1 Scope. This chapter applies to the design, construction, and installation of systems involved in the transfer of LNG and other hazardous fluids between storage containers or tanks and points of receipt or shipment by pipeline, ISO container, tank car, tank vehicle, or marine vessel.

15.2 General Requirements.

15.2.1 Loading and unloading areas shall be posted with signs that read "No Smoking."

15.2.2 Where multiple products are loaded or unloaded at the same location, loading arms, hoses, or manifolds shall be identified or marked to indicate the product or products to be handled by each system.

15.2.3 Purging of systems described in Section 15.1, when necessary for operations or maintenance, shall meet the requirements in 18.6.5.

15.3 Piping System.

15.3.1 Isolation valves shall be installed at the extremity of each transfer system.

N **15.3.2** Where power-operated isolation valves are installed, an analysis shall be made to determine that the closure time will not produce a hydraulic shock capable of causing line or equipment failure.

N **15.3.3** If excessive stresses are indicated by the analysis in 15.3.2, an increase of the valve closure time or other methods shall be used to reduce the stresses to a safe level.

15.4 Pump and Compressor Control.

15.4.1 In addition to a locally mounted device for shutdown of the pump or compressor drive, a readily accessible, remotely located device shall be provided a minimum of 25 ft (7.6 m) away from the equipment to shut down the pump or compressor in an emergency.

15.4.2 Remotely located pumps and compressors used for loading or unloading tank cars, tank vehicles, ISO containers, or marine vessels shall be provided with controls to stop their operation that are located at the loading or unloading area and at the pump or compressor site.

15.4.3 Controls located aboard a marine vessel shall be considered to be in compliance with 15.4.2.

15.4.4 Signal lights shall be provided at the loading or unloading area to indicate whether a remotely located pump or compressor used for loading or unloading is idle or in operation.

15.5 Marine Shipping and Receiving.

15.5.1 Berth Design Requirements.

15.5.1.1 The design of piers, docks, wharves, and jetties shall incorporate the following:

(1) Wave characteristics
(2) Wind characteristics
(3) Prevailing currents
(4) Tidal ranges
(5) Water depth at the berth and in the approach channel
(6) Maximum allowable absorbed energy during berthing and maximum face pressure on the fenders
(7) Arrangement of breasting dolphins
(8) Vessel approach velocity
(9) Vessel approach angle
(10) Minimum tug requirements, including horsepower
(11) Safe working envelope of the loading/unloading arms
(12) Arrangement of mooring dolphins

(13) Resistance to seismic forces, including earthquakes and tsunamis
(14) Resistance to hurricane winds, storm surge, and waves

15.5.2 Piping (or Pipelines).

15.5.2.1 Arms, hoses, and piping shall be located on the dock or pier so that they are not exposed to damage from vehicular traffic or other possible causes of physical damage.

15.5.2.2* Underwater pipelines shall be located or protected so that they are not exposed to damage from marine traffic, and their location shall be posted or identified and shall comply with recognized standards.

15.5.2.3 Isolation valving and bleed connections shall be provided at the loading or unloading manifold for both liquid and vapor return lines so that hoses and arms can be blocked off, drained or pumped out, and depressurized before disconnecting.

15.5.2.3.1 Liquid isolation valves, regardless of size, and vapor valves 8 in. (200 mm) and larger shall be equipped with powered operators in addition to a means for manual operation.

15.5.2.3.2 Power-operated valves shall be capable of being closed both locally and from a remote control station located at least 50 ft (15 m) from the manifold area.

15.5.2.3.3 Unless the valve automatically fails closed on loss of power, the valve actuator and its power supply within 50 ft (15 m) of the valve shall be protected against operational failure due to a fire exposure of at least a 10-minute duration.

15.5.2.3.4 Valves shall be located at the point of hose or arm connection to the manifold.

15.5.2.3.5 Bleeds or vents shall discharge to a safe location outdoors that is away from people, congested areas, and ignition sources.

15.5.2.4 In addition to the isolation valves at the manifold, each vapor return and liquid transfer line shall have a readily accessible isolation valve located on shore near the approach to the waterway, dock, or pier.

15.5.2.4.1 Where more than one line is involved, the valves shall be grouped in one location.

15.5.2.4.2 Valves shall be identified for their service.

15.5.2.4.3 Valves 8 in. (200 mm) and larger shall be equipped with powered operators.

15.5.2.4.4 Means for manual operation shall be provided.

15.5.2.5 Pipelines used only for liquid unloading shall be provided with a check valve located at the manifold adjacent to the manifold isolation valve.

15.5.2.6 Marine terminals used for loading ships or barges shall be equipped with a vapor return line designed to connect to the vessel's vapor return connections.

15.5.3* Emergency Shutdown System. Each marine LNG transfer system shall have an emergency shutdown (ESD) system that does the following:

(1) Can be activated manually
(2) Provides a system for a coordinated safe shutdown of all relevant LNG transfer components on the vessel, at the berth, and within the LNG plant
(3) Is activated automatically when fixed gas sensors measure gas concentrations exceeding 50 percent of the lower flammability limit

15.6 Tank Vehicle, Tank Car, and ISO Container Loading and Unloading Facilities.

15.6.1 Transfer shall be made only into tank cars approved for the service.

15.6.2 Tank vehicles not under the jurisdiction of the DOT shall comply with the following standards:

(1) LNG tank vehicles shall comply with CGA 341, *Standard for Insulated Cargo Tank Specification for Cryogenic Liquids.*
(2) LP-Gas tank vehicles shall comply with NFPA 58.
(3) Flammable liquid tank vehicles shall comply with NFPA 385.

15.6.3 A rack structure, if provided, shall be constructed of a noncombustible material.

15.6.4 A tank vehicle loading and unloading area shall be of sufficient size to accommodate the vehicles without excessive movement or turning of the vehicles.

15.6.5 Transfer piping, pumps, and compressors shall be located or protected by barriers so that they are protected from damage by rail or vehicle movements.

15.6.6 Isolation valves and bleed connections shall be provided at the loading or unloading manifold for both liquid and vapor return lines so that hoses and arms can be blocked off, drained of liquid, and depressurized before disconnecting.

15.6.7 Bleeds or vents shall discharge to a safe location that is outdoors, away from people, congested areas, and ignition sources.

15.6.8 In addition to the isolation valving at the manifold, an emergency shutdown valve shall be provided in each liquid and vapor line at least 25 ft (7.6 m) but not more than 100 ft (30 m) from each loading or unloading area.

15.6.8.1 Emergency valves or emergency remote actuation devices shall be visible and readily accessible for emergency use, and their location shall be posted or identified.

15.6.8.2 Where a common line serves multiple loading or unloading areas, only one emergency valve on the common line shall be required.

15.6.8.3 Where the loading or unloading area is closer than 25 ft (7.6 m) to the sending or receiving container, a valve that can be operated remotely from a point 25 ft to 100 ft (7.6 m to 30 m) from the area shall be installed.

15.6.9 Pipelines used only for liquid unloading shall have a check valve at the manifold adjacent to the manifold isolation valve.

15.7 Pipeline Shipping and Receiving.

15.7.1 Isolation valves shall be installed at all points where transfer systems connect into pipeline systems.

15.7.2 The pipeline system shall be designed with temperature and overpressure protection so that it cannot exceed its temperature or pressure limits.

15.7.3 Where multiple products are loaded or unloaded at the same location, loading arms, hoses, and manifolds shall be identified or marked to indicate the product or products to be handled by each system.

15.7.4 Bleed or vent connections shall be provided so that loading arms and hoses can be drained and depressurized prior to disconnecting.

15.7.5 If vented to a safe location, gas or liquid shall be permitted to be vented to the atmosphere to assist in transferring the contents of one container to another.

15.8 Hoses and Arms.

15.8.1 Hoses or arms used for transfer shall be designed for the temperature and pressure conditions of the loading or unloading system.

15.8.2 Hoses shall be approved for the service and shall be designed for a bursting pressure of at least five times the working pressure.

15.8.3 Flexible metallic hose or pipe and swivel joints shall be used where operating temperatures can be below −60°F (−51°C).

15.8.4 Loading arms used for marine loading or unloading shall have alarms to indicate that the arms are approaching the limits of their extension envelopes.

15.8.5 Counterweights shall be selected to operate with ice formation on uninsulated hoses or arms.

15.8.6 Hoses shall be tested at least annually to the maximum pump pressure or relief valve setting and shall be inspected visually before each use for damage or defects.

15.8.7 Marine loading or unloading operations shall be periodically tested as required by the authority having jurisdiction.

15.9 Communications and Lighting.

15.9.1 Communications shall be provided at loading and unloading locations to allow the operator to be in contact with other personnel associated with the loading or unloading operation.

15.9.2 Facilities shall have lighting at the transfer area that provides for illumination of no less than 54 lux at the transfer connection and 11 lux at all other work areas.

Δ **15.9.3** The LNG marine transfer area shall have a ship-to-shore communication system and a separate emergency ship-to-shore communication system that allows voice communication between the person in charge of transfer operations on the vessel, the person in charge of shoreside transfer operation, and personnel in the control room.

15.9.4 The communication system required in 15.9.3 shall be continuously monitored both aboard ship and at the terminal.

Chapter 16 Fire Protection, Safety, and Security

16.1 Scope.

16.1.1 This chapter covers equipment and procedures designed to minimize the consequences from released LNG and other hazardous fluids in facilities constructed and arranged in accordance with this standard.

16.1.2 The provisions in Chapter 16 augment the leak and spill control provisions in other chapters.

16.1.3 This chapter includes basic plant security provisions.

16.2* General. Fire protection shall be provided for all LNG facilities.

16.2.1* The extent of such protection shall be determined by an evaluation based on fire protection engineering principles, analysis of local conditions, hazards within the facility, and exposure to or from other property.

N **16.2.1.1** Each LNG plant shall conduct the fire protection evaluation.

N **16.2.1.2*** The fire protection evaluation shall be conducted and fire protection equipment installed before the introduction of hazardous fluids at new plants or significantly altered facilities.

N **16.2.1.3** The fire protection evaluation for existing plants shall be reviewed and updated at intervals not exceeding two calendar years, but at least once every 27 months.

N **16.2.1.4*** Where results of the re-evaluation required by 16.2.1.3 for existing LNG plants identifies fire protection system modifications to existing systems, or installation of new fire protection systems, they must be implemented after completion of the evaluation as follows:

(1) Modification, expansion, or replacement of fire protection systems or components shall be installed within one calendar year not to exceed 15 months.
(2) New fire protection systems shall be installed within two calendar years not to exceed 27 months or as approved by the AHJ.

Δ **16.2.1.5*** Protection installed as a result of the evaluation in 16.2.2 shall be designed, engineered, installed and tested based upon fire protection equipment standards incorporated by reference adhering to the following standards:

(1) NFPA 10
(2) NFPA 11
(3) NFPA 12
(4) NFPA 12A
(5) NFPA 13
(6) NFPA 14
(7) NFPA 15
(8) NFPA 16
(9) NFPA 17
(10) NFPA 20
(11) NFPA 22
(12) NFPA 24
(13) NFPA 25
(14) NFPA 68
(15) NFPA 69
(16) *NFPA 72*
(17) NFPA *101*
(18) NFPA 750
(19) NFPA 1221
(20) NFPA 1901
(21) NFPA 1961
(22) NFPA 1962
(23) NFPA 1963
(24) NFPA 2001

16.2.2* The evaluation shall determine the following:

(1) The type, quantity, and location of equipment necessary for the detection and control of fires, leaks, and spills of LNG and other hazardous fluids
(2) The type, quantity, and location of equipment necessary for the detection and control of potential nonprocess and electrical fires
(3) The methods necessary for protection of the equipment and structures from the effects of fire exposure
(4) Requirements for fire protection water systems
(5)* Requirements for fire-extinguishing and other fire control equipment
(6) The equipment and processes to be incorporated within the emergency shutdown (ESD) system, including analysis of subsystems, if any, and the need for depressurizing specific vessels or equipment during a fire emergency or hazardous release
(7) The type and location of sensors necessary to initiate automatic operation of the ESD system or its subsystems
(8) The availability and duties of individual plant personnel and the availability of external response personnel during an emergency
(9)* The personal protective equipment, special training, and qualification needed by individual plant personnel for their respective emergency duties as specified by NFPA 600
(10) Requirements for other hazard protection equipment and systems

16.3 Emergency Shutdown (ESD) Systems.

16.3.1* Each LNG facility shall have an ESD system(s) to isolate or shut off a source of LNG and other hazardous fluids, and to shut down equipment whose continued operation could add to or sustain an emergency.

16.3.2 Valves, control systems, and equipment required by the ESD system shall not be required to duplicate valves, control systems, and equipment installed to meet other requirements of the standard where multiple functions are incorporated in the valves, control systems, and equipment. The valves, control systems, and equipment shall meet the requirements for ESD systems.

16.3.3 If equipment shutdown will introduce a hazard or result in mechanical damage to equipment, the shutdown of any equipment or its auxiliaries shall be omitted from the ESD system if the effects of the continued release of flammable or combustible fluids are controlled.

Δ **16.3.4** The ESD system(s) shall be of a fail-safe design and shall be installed, located, or protected to minimize the possibility that it will become inoperative in the event of an emergency or a failure at the normal control system.

Δ **16.3.5*** Where motor-operated valves that are part of ESD systems are not fail-safe, they shall have all components that are located within 50 ft (15 m) of the equipment protected in either of the following ways:

(1) Installed or located where they cannot be exposed to a fire
(2) Protected against failure due to a fire exposure of at least 10 minutes

16.3.6 Operating instructions identifying the location and operation of emergency controls shall be posted in the facility area.

16.3.7 Manual actuators shall be located in an area accessible in an emergency, shall be at least 50 ft (15 m) from the equipment they serve, and shall be marked with their designated function.

N **16.3.8*** When determined to be appropriate as part of the evaluation of fire and safety protection systems by 16.2.2(6), emergency depressurizing means shall be provided where necessary for safety. The depressurization system shall be either manual or automated and shall be designed and sized based on requirements of recognized standards.

N **16.3.9*** ESD systems shall be tested based on recognized standards.

16.4 Hazard Detection.

16.4.1 Areas, including enclosed buildings and enclosed drainage channels, that can have the presence of LNG or other hazardous fluids shall be monitored as required by the evaluation in 16.2.1.

16.4.2* Gas Detection.

16.4.2.1 Continuously monitored flammable gas, toxic gas, and oxygen depletion detection systems shall sound an alarm at the plant site and at a constantly attended location if the plant site is not attended continuously.

16.4.2.2 Flammable gas detection systems shall activate an audible and a visual alarm at not more than 25 percent of the LFL of the gas or vapor being monitored or point gas detectors and 1 LFL-m for open-path gas detectors.

N **16.4.2.3** Flammable gas detection systems shall activate a second audible and visual alarm at not more than 50 percent of the LFL of the gas or vapor being monitored for point gas detectors and not more than 3 LFL-m for open-path gas detectors.

N **16.4.2.3.1** If so determined by an evaluation in accordance with 16.2.1, gas detectors shall be permitted to activate portions of the ESD system.

N **16.4.2.4** Flammable gas detection systems setpoints shall account for the potential of different flammable gases and vapors being released in the calibration or setpoint of the detectors.

N **16.4.2.5** Toxic gas detectors shall be present in areas where toxic fluids can be released and shall activate an audible and a visual alarm at no more than 25 percent of the AEGL-3 or ERPG-3 level or other approved toxic concentration.

N **16.4.2.6** Oxygen depletion gas detectors shall be present in areas where asphyxiates can be released and migrate into occupied buildings and shall activate an audible and a visual alarm at no less than 19.5 percent oxygen levels or other approved oxygen concentration.

16.4.3 Fire Detectors.

16.4.3.1 Fire detectors shall activate an audible and a visual alarm at the plant site and at a constantly attended location if the plant site is not attended continuously.

16.4.3.2 If so determined by an evaluation in accordance with 16.2.1, fire detectors shall be permitted to activate portions of the ESD system.

 Shaded text = Revisions. Δ = Text deletions and figure/table revisions. • = Section deletions. *N* = New material.

16.4.4 Leak detection shall activate an audible and visual alarm at the plant site and at a constantly attended location if the plant is not continuously attended.

16.4.5* The detection systems shall be designed, installed, and maintained in accordance with *NFPA 72*.

N **16.4.6** Where fire protection systems are installed in accordance with *NFPA 72* and are planned to be integrated with other systems, the integrated systems shall be tested in accordance with NFPA 4.

16.5 Fire Protection Water Systems.

16.5.1 A water supply and a system for distributing and applying water shall be provided for protection of exposures; for cooling containers, equipment, and piping; and for controlling unignited leaks and spills, unless an evaluation in accordance with 16.2.1 determines that the use of water is unnecessary or impractical.

16.5.2 The fire water supply and distribution systems, if provided, shall simultaneously supply water to fixed fire protection systems, including monitor nozzles, at their design flow and pressure, involved in the maximum single incident expected in the plant plus an allowance of 1000 gpm (63 L/sec) or as determined from the fire evaluation required in 16.2.1 for hand hose streams for at least 2 hours.

16.5.3 Where provided, fire protection water systems shall be designed in accordance with NFPA 13, NFPA 14, NFPA 15, NFPA 20, NFPA 22, NFPA 24, NFPA 750, or NFPA 1961 as applicable.

16.6 Fire Extinguishing and Other Fire Control Equipment.

16.6.1* Portable or wheeled fire extinguishers shall be recommended for gas fires by their manufacturer.

16.6.1.1 Portable or wheeled fire extinguishers shall be available at strategic locations, as determined in accordance with 16.2.1, within an LNG facility and on tank vehicles.

16.6.1.2 Portable and wheeled fire extinguishers shall conform to the requirements of NFPA 10.

16.6.1.3 Handheld portable dry chemical extinguishers shall contain minimum nominal agent capacities of 20 lb (9 kg) or greater and shall have a minimum 1 lb/sec (0.45 kg/sec) agent discharge rate.

16.6.1.4 For LNG plant hazard areas where minimal Class A fire hazards are present, the selection of potassium bicarbonate–based dry chemical extinguishers is recommended.

16.6.1.5 Wheeled portable dry chemical extinguishers shall contain minimum nominal agent capacities of 125 lb (56.7 kg) or greater and shall have a minimum 2 lb/sec (0.90 kg/sec) agent discharge rate.

16.6.2 If provided, automotive and trailer-mounted fire apparatus shall not be used for any other purpose.

16.6.3 Fire trucks shall conform to NFPA 1901.

16.6.4 Automotive vehicles assigned to the plant shall be provided with a minimum of one portable dry chemical extinguisher having a capacity of not less than 18 lb (8.2 kg).

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16.7 Personnel Safety.

16.7.1* Protective clothing that will provide protection against the effects of exposure to LNG shall be available and readily accessible at the LNG plant.

16.7.2* Employees who are involved in emergency response activities beyond the incipient stage shall be equipped with protective clothing and equipment and trained in accordance with NFPA 600.

16.7.3* Written practices and procedures shall be developed to protect employees from the hazards of entry into confined or hazardous spaces.

16.7.4* At least three portable flammable gas indicators shall be readily available.

16.8 Security.

16.8.1 Security Assessment.

16.8.1.1* A security assessment covering hazards, threats, vulnerabilities, and consequences shall be prepared for the LNG plant.

16.8.1.2 The security assessment shall be available to the authority having jurisdiction on a nonpublic basis.

16.8.2 The LNG plant operator shall provide a security system with controlled access that is designed to prevent entry by unauthorized persons.

16.8.3 At LNG plants, there shall be a protective enclosure, including a peripheral fence, wall, building wall, or approved natural barrier enclosing major facility components, including, but not limited to, the following, except where the entire onshore facility is enclosed:

(1) LNG storage containers
(2) Impoundment systems
(3) Flammable refrigerant storage tanks
(4) Hazardous materials storage tanks, including those storing toxic materials
(5) Flammable liquid storage tanks
(6) Other hazardous materials storage areas
(7) Outdoor process equipment areas
(8) Buildings housing process or control equipment
(9) Onshore loading and unloading facilities
(10) Control rooms and stations
(11) Control systems
(12) Fire control equipment
(13) Security communications systems
(14) Alternative power sources

16.8.3.1 The LNG plant shall be secured either by a single continuous enclosure or by multiple independent enclosures or approved barrier(s) that meet the following requirements:

(1) Each protective enclosure shall have sufficient strength and configuration to obstruct unauthorized access to the facilities enclosed.
(2) Openings in or under protective enclosures shall be secured by grates, doors, or covers of construction and fastening of sufficient strength such that the integrity of the protective enclosure is not reduced by any opening.
(3) Ground elevations outside a protective enclosure shall be graded in a manner that does not impair the effectiveness of the enclosure.

(4) Protective enclosures shall not be located near features outside of the facility, such as trees, poles, or buildings, which could be used to breach the enclosure.
(5) At least two accesses shall be provided in each protective enclosure and be located to minimize the escape distance in the event of an emergency.
(6) Each access shall be locked unless it is continuously guarded, and with the following provisions:
    (a) During normal operations, an access shall be permitted to be unlocked only by persons designated in writing by the operator.
    (b) During an emergency, a means shall be readily available to all facility personnel within the protective enclosure to open each access.

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N **16.8.4 Security Communications.** A means shall be provided for the following:

(1) Prompt communication between personnel having supervisory security duties and law enforcement officials
(2) Direct communication between all on-duty personnel having security duties and all control rooms and control stations

N **16.8.5 Security Monitoring.** Each protective enclosure and the area around each facility shall be monitored for the presence of unauthorized persons.

N **16.8.5.1** Monitoring shall be by visual observation in accordance with the schedule in the security procedures or by security warning systems that continuously transmit data to an attended location.

N **16.8.5.2** At an LNG plant with less than 250,000 bbl(40,000 m^3) of storage capacity, only the protective enclosure shall be required to be monitored.

N **16.8.6 Warning Signs.**

N **16.8.6.1** Warning signs shall be conspicuously placed along each protective enclosure at intervals so that at least one sign is recognizable at night from a distance of 100 ft (30 m) from any direction that could reasonably be used to approach the enclosure.

N **16.8.6.2** Signs shall be marked with the words "NO TRESPASSING," or words of comparable meaning, on a background of sharply contrasting colors.

16.8.7 LNG plants shall be illuminated to a minimum of 2.2 lux in the vicinity of protective enclosures and in other areas as necessary to promote security of the LNG plant.

Chapter 17 Requirements for Stationary Applications for Small Scale LNG Facilities

17.1 Scope.

N **17.1.1** Chapter 1, Administration shall apply to this chapter.

Δ **17.1.2** This chapter provides an alternative set of requirements for LNG plants that meet all of the following limitations:

(1) LNG storage capacity complies with one of the following:
    (a) Individual LNG container water capacity not exceeding 264,000 gal (1000 m^3) water capacity with an aggregate 1,056,000 gal (3997 m^3) water capacity of LNG storage constructed in accordance with the ASME *Boiler and Pressure Vessel Code*
    (b) LNG tank systems with an aggregate capacity not exceeding 1,056,000 gal (3997 m^3) water capacity of LNG storage
(2) Aggregate mass of flammable hazardous fluid, excluding methane and LNG, not exceeding 25,000 lb (11,340 kg) and individual tanks with a storage capacity not exceeding 10,000 lb (4536 kg)
(3) Toxic fluids with a 60-minute AEGL-2 of 10,000 ppm or less and an aggregate mass of toxic fluids is not exceeding 25,000 lb (11,340 kg) and individual tanks with a storage capacity not exceeding 10,000 lb (4536 kg)
(4) LNG container liquid line penetrations not exceeding 6 in. (15.24 cm) nominal pipe size
(5) LNG container MAWP not exceeding 300 psig (2068 kPa)

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17.2 Control Rooms. Small scale LNG plants with less than 264,000 gal (1000 m^3) water capacity using container constructed in accordance with the ASME *Boiler and Pressure Vessel Code* and with no liquefaction capability shall not be required to comply with requirements for a control center in Section 4.7.

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17.3 Plant Siting.

N **17.3.1* Plant Site Provisions.**

N **17.3.1.1** A written plant and site evaluation shall identify and analyze potential incidents that have a bearing on the safety of plant personnel and the surrounding public.

N **17.3.1.2** The plant and site evaluation shall also identify safety and security measures incorporated in the design and operation of the plant considering the following, as applicable:

(1) Process hazard analysis
(2) Transportation activities that might impact the proposed plant
(3) Adjacent facility hazards
(4) Meteorological and geological conditions
(5) Security threat and vulnerability analysis

N **17.3.1.3** A written plant and site evaluation shall evaluate the consequences associated with potential incidents from identified hazards.

N **17.3.1.4** All-weather accessibility to the plant for personnel safety and fire protection shall be provided.

N **17.3.1.5** Soil and general investigations of the site shall be made to determine the design basis for the facility.

N **17.3.2 Site Provisions for Spill and Leak Control.**

N **17.3.2.1 General.**

N **17.3.2.1.1** Provisions shall be made to minimize the potential of discharge of LNG or other hazardous liquids at containers, piping, and other equipment such that a discharge from any of these does not endanger adjoining property, occupied buildings, or important process equipment and structures or reach waterways.

N **17.3.2.1.2** An analysis shall be performed that determines the practical limits of unimpounded liquid spills.

N **17.3.2.1.2.1** If the analysis determines that the liquid does not remain on the property or could enter underground conduits, LNG and hazardous liquid containers shall be provided with one of the following methods to contain any release:

(1) An impounding area surrounding the container(s) that is formed by a natural barrier, dike, impounding wall, or combination thereof complying with Chapter 13 and Chapter 6
(2) An impounding area formed by a natural barrier, dike, excavation, impounding wall, or combination thereof complying with Chapter 13 and Chapter 6, plus a natural or man-made drainage system surrounding the container(s) that complies with Chapter 13 and Chapter 6
(3) Where the container is constructed below or partially below the surrounding grade, an impounding area formed by excavation complying with Chapter 13 and Chapter 6
(4) Secondary containment as required for double-, full-, or membrane-containment tank systems complying with Chapter 13 and Chapter 6

N **17.3.2.1.3** Where there is a possibility for hazardous liquid releases to accumulate and endanger adjoining property, occupied buildings, or important process equipment and structures, or reach waterways, the following areas shall be graded, drained, or provided with impoundment:

(1) Process areas
(2) Vaporization areas
(3) Liquefaction areas
(4) Transfer areas for LNG, flammable refrigerants, and flammable liquids
(5) Areas immediately surrounding flammable refrigerant and flammable liquid storage tanks

N **17.3.2.1.4** Secondary containment systems designed in accordance with 10.13.3.2 shall be permitted to serve as an impounding area.

N **17.3.2.1.5** If impounding areas are required to comply with 17.3.2.1.7, the areas shall be in accordance with Chapter 13 and Chapter 6.

N **17.3.2.1.6** The provisions of 17.3.2.1.1, 17.3.2.1.2, 17.3.2.1.3 and 17.3.2.1.7 that apply to adjoining property or waterways shall be permitted to be waived or altered at the discretion of the authority having jurisdiction where the change does not constitute a distinct hazard to life or property or conflict with applicable federal, state, and local (national, provincial, and local) regulations.

N **17.3.2.1.7** Site preparation shall include provisions for retention of spilled LNG and other hazardous liquids where liquids might accumulate on the ground within the limits of plant property and for surface water drainage.

N **17.3.2.2 Setback Analysis.** Setback for equipment assumes the use of product retention valves are in accordance with 17.3.2.2.1 through 17.3.2.2.4.

N **17.3.2.2.1 Automatic Product Retention Valves.**

N **17.3.2.2.1.1** All liquid and vapor connections, with the exceptions of relief valve connections, liquid lines ½ in. or less pipe size, and vapor lines 2 in. or less pipe size, shall be equipped with automatic fail-safe product retention valves.

N **17.3.2.2.1.2** A remote manual product retention valve with at least one person in attendance when equipment is in operation shall be permitted to be used in lieu of an automated product retention valve

N **17.3.2.2.1.3*** Automatic fail-safe product retention valves shall be designed to close on the occurrence of any of the following conditions:

(1) Fire detection or exposure,
(2) Uncontrolled flow of LNG from the container
(3) Manual operation from a local and remote location

N **17.3.2.2.1.4** Connections used only for flow into the container shall be equipped with either two backflow valves, in series, or an automatic fail-safe product retention valve.

N **17.3.2.2.2** Setback distance to the property line shall be the greater of Table 17.3.2.2.3, (or Table 17.3.2.2.4 for each underground container), or Equation 17.3.2.2.2.

[17.3.2.2.2]

$$Setback = Coef * d^{0.86} * (P + 15)^{0.215}$$

where:

Setback (ft) = minimum distance from the product retention valve of each container's largest liquid line to offsite buildings and property lines that can be built upon
d (in.) = inside diameter of container's largest liquid line
P (psig) = maximum allowable working pressure (MAWP) for the container plus liquid head, where 1 ft of head equals 0.182 psi
Coef = see Table 17.3.2.2.2

N **17.3.2.2.2.1** Setback modifications for alternate retention devices:

(1) Remote manual retention devices shall be permitted to be used in lieu of fully automatic retention devices if the calculated setback from 17.3.2.2.1.2 is multiplied by 4.
(2) The setback calculated in 17.3.2.2.1.2 shall be multiplied by 0.9 if the automatic retention devices on the largest liquid lines can demonstrate a time to closure of 30 seconds or less.

N **17.3.2.2.3** The minimum distance from the edge of an impoundment or container drainage system serving aboveground and mounded containers larger than 1000 gal (3.8 m^3) shall be in accordance with Table 17.3.2.2.3 for each of the following:

(1) Nearest offsite building
(2) The property line that can be built upon
(3) Spacing between containers

N **17.3.2.2.4** Underground LNG containers shall be installed in accordance with Table 17.3.2.2.4.

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Table 17.3.2.2.2 Coefficient for Setback Formula

Area A (in.^{2}) = Cumulative inside area of all LNG container liquid penetrations on site (including liquid over the top penetrations)	*Coefficient*
$A < 45$ in.^{2}	14
45 in.2 $\le A \le 120$ in.^{2}	$21.6 - \left(\frac{120 - A}{75}\right) * 7.6$
$A > 120$ in.^{2}	21.6

Table 17.3.2.2.3 Distances from Containers and Exposures

Container Water Capacity		Minimum Distance from Edge of Impoundment or Container Drainage System to Offsite Buildings and Property Lines That Can Be Built Upon		Minimum Distance Between Storage Containers	
gal	m³	ft	m	ft	m
1000–2000	3.8–7.6	15	4.6	5	1.5
2001–18,000	≥7.6–68.1	25	7.6	5	1.5
18,001–30,000	≥68.1–114	50	15	5	1.5
30,001–70,000	≥114–265	75	23	QSD*	
70,001–100,000	≥265–379	100	30.5	QSD*	
100,001–120,000	≥379–454	125	38	QSD*	
120,001–200,000	≥454–757	200	61	QSD*	
200,001–1,056,000	≥757–4000	300	91.4	QSD*	

*QSD = ¼ of the sum of the diameters of adjacent containers [5 ft (1.5 m) minimum]

Table 17.3.2.2.4 Distances from Underground Containers and Exposures

Container Water Capacity		Minimum Distance from Buildings and the Adjoining Property Line That Can Be Built Upon		Distance Between Containers	
gal	m³	ft	m	ft	m
<18,000	<68.1	15	4.6	15	4.6
18,000–30,000	68.1–114	25	7.6	15	4.6
30,001–100,000	≥114–379	40	12.2	15	4.6
100,001–120,000	≥379–454	65	20	15	4.6
120,001–200,000	≥454–757	100	30.5	15	4.6
20,0001–1,056,000	≥757–4000	150	45.7	15	4.6

17.4 Plant Layout.

17.4.1 Chapter 6 shall apply to this chapter except 6.3.1, 6.4.5, 6.8.1, and 6.8.2.

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17.4.2 Underground LNG tanks shall be installed in accordance with Table 17.3.2.2.4 with respect to distance between containers.

17.5 Process Equipment. Process equipment shall comply with Chapter 7, Process Equipment.

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17.6 Stationary LNG Storage. LNG storage shall comply with Chapter 8, Stationary LNG Storage, except as modified in this chapter.

N **17.6.1** Ground motion instrumentation (8.5.2.4) shall not be required for vacuum insulated ASME containers.

N **17.6.2** Tank systems shall have no pipe penetrations below the liquid level except for storage tank systems classified as containment-with-penetrations per API Std 625, *Tank Systems for Refrigerated Liquefied Gas Storage.*

17.6.3 All liquid and vapor connections, except relief valve connections, liquid lines ½ in. (2.7 mm) or less pipe size, or vapor lines 2 in. (50.8 mm) or less pipe size, shall be equipped with automatic fail-safe product retention valves.

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17.6.4 Pressure Gauging and Control. Each container shall be equipped with a pressure gauge connected to the container at a point above the maximum liquid level that has a permanent mark indicating the maximum allowable working pressure (MAWP) of the container.

17.7 Vaporization Facilities. Vaporization facilities shall comply with Chapter 9, Vaporization Facilities.

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17.8 Piping Systems and Components.

17.8.1 All piping that is part of an LNG container shall be in accordance with stationary LNG storage requirement in Chapter 8 for the applicable storage container type.

17.8.2 All other process piping in hazardous fluid service shall be in accordance with Chapter 10 and ASME B31.3, *Process Piping.*

17.9 Instrumentation and Electrical Services. Instrumentation and electrical services shall comply with Chapter 11, Instrumentation and Electrical Services.

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17.10 Plant Facilities Design. Plant facilities design shall comply with Chapter 12, Plant Facilities Design.

17.11 Impounding Area and Drainage System Design Capacity. Impounding area and drainage system design capacity shall comply with Chapter 13, Impounding Area and Drainage System Design Capacity, when required by 17.3.2.1.2 and 17.3.2.1.2.1.

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17.12 Transfer Systems for LNG and Other Hazardous Fluids. Transfer systems for LNG and other hazardous fluids shall comply with Chapter 15, Transfer Systems for LNG and Other Hazardous Fluids.

• **17.13 Fire Protection, Safety, and Security.** Fire protection, safety, and security shall comply with Chapter 16, Fire Protection, Safety, and Security.

• **17.14 Operating, Maintenance, and Personnel Training.** Operating, maintenance, and personnel training shall comply with Chapter 18, Operating, Maintenance, and Personnel Training, with the follow differences:

(1) Positive identification of all persons entering the plant and in the plant shall be required in lieu of requirements in 18.5.1(6).
(2) Vehicle traffic shall be prohibited on the pier or dock within 100 ft (30 m) of the loading and unloading or shorter distances as approved while transfer operations are in progress in lieu of requirements in 18.8.7.4.1.
(3) General cargo, other than ships' stores for the LNG tank vessel, shall not be handled over a pier or dock within 100 ft (30 m) or shorter distances as approved, of the point where connections are made for LNG, and flammable fluids transfer while LNG or flammable fluids are being transferred through piping systems in lieu of requirements in 18.8.7.4.6.

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Chapter 18 Operating, Maintenance, and Personnel Training

18.1* Scope. This chapter contains basic requirements and minimum standards for the safety aspects of the operation and maintenance of LNG plants.

18.2 General Requirements.

18.2.1* Each operating company shall develop documented operating, maintenance, and training procedures, based on experience and conditions under which the LNG facility is operated.

18.2.2 The operating company shall meet all of the following procedures:

(1) Document procedures and plans covering operation, maintenance, training, and security
(2) Maintain up-to-date drawings, charts, and records of LNG facility equipment
(3) Revise plans and procedures when operating conditions or LNG facility equipment are revised or as a result of lessons learned from an incident investigation
(4) Ensure cooldown of components in accordance with 18.3.5
(5) Establish a documented emergency plan
(6) Establish liaisons with local authorities such as police, fire department, or municipal works to coordinate the emergency plans and their roles in emergency situations
(7)* Analyze and document all safety-related incidents to determine their cause and prevent the possibility of recurrence

18.3 Manual of Operating Procedures.

18.3.1 All LNG facility components shall be operated in accordance with the operating procedures manual.

18.3.2 The operating procedures manual shall be accessible to all LNG facility personnel and shall be kept readily available in the operating control center.

18.3.3 The operating manual shall be updated when there are changes in equipment or procedures.

18.3.4 The operating manual shall include procedures for the startup and shutdown of all components of the LNG facility, including those for initial startup of the LNG facility, to ensure that all components operate satisfactorily.

18.3.5 The operating manual shall include procedures for purging components, making components inert, and cooldown of components in accordance with 18.6.5 for purging and 18.6.3 for cooldown.

18.3.5.1 Procedures shall ensure that the cooldown of each system of components that is under the operating company's control, and that is subjected to cryogenic temperatures, is limited to a rate and distribution pattern that maintains the thermal stresses within the design limits of the system during the cooldown period regarding the performance of expansion and contraction devices.

18.3.6 The operating manual shall include procedures to ensure that each control system is adjusted to operate the process within its design limits.

Δ **18.3.7** The operating manual of LNG plants shall include procedures to maintain the temperatures, levels, pressures, pressure differentials, and flow rates within their design limits for installed equipment, including:

(1) Fired heaters and boilers
(2) Turbines and other prime movers
(3) Pumps, compressors, and expanders
(4) Purification, treatment, and regeneration equipment
(5) Vaporizers, heat exchangers, and cold boxes
(6) Process and storage vessels, tanks, and containers
(7) Transfer equipment
(8) Safety-related equipment

18.3.8 The operating manual shall include procedures for the following:

(1) Maintaining the vaporization rate, temperature, and pressure so that the resultant gas is within the design tolerance of the vaporizer and the downstream piping
(2) Determining the existence of any abnormal conditions and the response to those conditions in the LNG facility
(3) The safe transfer of LNG and hazardous fluids, including prevention of overfilling of containers
(4) Security

18.3.9 The operations manual shall include procedures for monitoring operations.

• **18.3.10** Written procedures shall be kept up to date and available to all personnel engaged in transfer operations.

N **18.3.11*** Changes to written procedures shall be documented and reviewed after consideration of operability, safety, and security.

18.4 Emergency Procedures.

18.4.1 Each operations manual shall contain emergency procedures.

18.4.2 The emergency procedures shall include, at a minimum, emergencies that are anticipated from an operating malfunction, structural collapse of part of the LNG facility, personnel error, forces of nature, and activities carried on adjacent to the plant.

18.4.3 The emergency procedures shall include but not be limited to procedures for responding to controllable emergencies, including the following:

(1) Notification of personnel
(2) Use of equipment appropriate for handling the emergency
(3) The shutdown or isolation of various portions of the equipment
(4) Other steps to ensure that the escape of gas or liquid is promptly cut off or reduced as much as possible

18.4.4 The emergency procedures shall include procedures for recognizing an uncontrollable emergency and for taking action to achieve the following:

(1) Minimizing harm to the personnel at the LNG plant and to the public
(2) Prompt notification of the emergency to the appropriate local officials, including the possible need to evacuate persons from the vicinity of the LNG plant

18.4.5 The emergency procedures shall include procedures for coordinating with local officials in the preparation of an emergency evacuation plan that sets forth the steps necessary to protect the public in the event of an emergency, including the following:

(1) Quantity and location of fire equipment throughout the LNG plant
(2) Potential hazards at the LNG plant
(3) Communication and emergency control capabilities at the LNG plant
(4) Status of each emergency

18.4.6 Emergency procedures shall include procedures for dealing with unignited gas releases.

18.4.7 Each facility that handles LNG shall develop a contingency plan to address potential incidents that can occur in or near the transfer area, including the following:

(1) A description of the fire equipment and systems and their operating procedures, including a plan showing the locations of all emergency equipment
(2) LNG release response procedures, including contact information for local response organizations
(3) Emergency procedures for unmooring a vessel, including the use of emergency towing wires (e.g., "fire warps")
(4) Tug requirements for emergency situations and for specific foreseeable incidents that are berth-specific
(5) Telephone numbers of authorities having jurisdiction, hospitals, fire departments, and other emergency response agencies

N **18.4.8** Emergency procedures and contingency plans shall be reviewed annually, and revised as necessary.

N **18.5 Security Procedures.** Based upon the security assessment performed under 16.8.1.1 and additional security requirements within this standard, each operator shall prepare and follow one or more manuals of written procedures to provide security for each LNG plant.

N **18.5.1** The procedures shall be available at the plant and any remote monitoring location and include at least the following:

(1) A description and schedule of security inspections and patrols performed
(2) A list of security personnel positions or responsibilities utilized at the LNG plant
(3) A brief description of the duties associated with each security personnel position or responsibility
(4) Instructions for actions to be taken, including notification of other appropriate plant personnel and law enforcement officials, when there is any indication of an actual or attempted breach of security
(5) Methods for determining which persons are allowed access to the LNG plant
(6) Positive identification of all persons entering the plant and on the plant, including methods at least as effective as picture badges
(7) Liaison with local law enforcement officials to keep them informed about current security procedures

N **18.5.2** The procedures shall be reviewed every two years not to exceed 27 months or at intervals determined by the AHJ, and revised as necessary. In the event security conditions change, the procedures shall be updated more frequently.

18.6 Monitoring Operations.

Δ **18.6.1* Control Center.** Operations monitoring shall be conducted continuously.

N **18.6.1.1** At plants with onsite control centers, operating personnel shall be permitted to leave the control room to perform scheduled field inspections or to address activities in the field related to the plant's operation.

N **18.6.1.2** Safety-related alarms required by 4.7.2 shall provide notice to onsite personnel performing operations monitoring unless the control center has an alternate method to communicate during operations monitoring.

N **18.6.1.3** Inspections shall be conducted at least at the intervals set out in the written operating procedures referred to in Section 18.3.

18.6.2 LNG Tank System Foundation.

18.6.2.1 Foundation heating systems shall be monitored at least daily to ensure that the 32°F (0°C) isotherm is not penetrating the soil.

N **18.6.2.2** LNG tank system foundation elevation surveys shall occur every 3 years, as well as after an operating basis earthquake and after indication of an abnormally cool area.

Δ **18.6.2.3*** Any settlement in excess of that anticipated in the design shall be investigated and corrective action taken as required.

18.6.3 Cooldown.

N **18.6.3.1** Cooldown procedures shall limit the rate and distribution pattern of the cooling medium such that it keeps thermal stresses within design limits during the cooldown period.

N **18.6.3.2** Each cryogenic piping system that is under the operating company's control shall be checked during and after cooldown stabilization for movement beyond the design limits and leaks in areas where there are flanges, valves, and seals.

18.6.4 Depressurizing.

N **18.6.4.1** Depressurizing procedures for maintenance shall be developed.

N **18.6.4.2** The discharge from depressurizing shall be directed to a safe location outdoors that is away from personnel, congested areas, and ignition sources.

18.6.5 Purging.

N **18.6.5.1** A detailed and specific written purging procedure shall be developed prior to purging piping and equipment into initial service and into and out of service once in operation.

N **18.6.5.1.1** The purge procedures shall include, at a minimum, the following:

(1) Isolation points
(2) Inert media inlet and vent points that are in accordance with Section 10.9 piping requirements
(3) Purge media
(4) Purge endpoints
(5) Sequence of out-of-service and into-service purge
(6) Instrumentation used to evaluate the purging progress

18.6.5.2* Piping and equipment systems shall be cleaned, dried, purged, and tightness tested in a safe manner. *(See Section 10.9.)*

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N **18.6.5.3** Cleaning, drying, purging, and tightness testing shall be conducted using an inert or nonflammable nontoxic medium or mechanical means unless the procedures also meet the requirements of NFPA 56or are approved.

18.6.5.4 The temperature of the clean out, dry out, purge, and tightness test mediums shall be within the design temperature limits of the container or other equipment.

18.6.5.5 The pressure of the container or other equipment during clean out, dry out, purge, and tightness testing shall be within the design pressure limits of the container.

18.6.5.5.1 Taking an LNG container out of service shall not be regarded as a normal operation.

18.6.5.5.2 The activities of 18.6.5 shall require the preparation of detailed procedures.

18.6.5.5.3 Only experienced, trained personnel shall dry, purge, or cool down LNG containers.

18.6.5.5.4 Before an LNG container is put into service, the air shall be displaced by an inert gas, per a written purging procedure.

18.6.5.5.5* Before a container is taken out of service, the natural gas in the container shall be purged from the container with an inert gas, per a written purging procedure.

N **18.6.5.6 Purge Endpoints.**

N **18.6.5.6.1** The purge endpoints defined in the purge procedure shall be verified by calibrated combustible gas analyzation instruments at all identified purge vent locations.

N **18.6.5.6.2*** The purge endpoints shall be determined by taking into account remaining concentrations of inert gases and oxygen, the system pressure and temperature, and the potential for autoignition.

18.6.5.7 During purging operations, the oxygen content of the container or other equipment shall be monitored by the use of an oxygen analyzer.

N **18.7 Commissioning.**

N **18.7.1** Prior to startup of facilities, a commissioning plan shall be developed to test and verify that all components are functional within their design ranges.

N **18.7.2** Piping shall be commissioned in accordance with ASME B31.1, *Power Plant Piping*; B31.3, *Process Piping*; B31.4, *Pipeline Transportation Systems for Liquids and Slurries*; B31.5, *Refrigeration Piping and Heat Transfer Components*; or B31.8, *Gas Transmission and Distribution Piping Systems*; as applicable.

N **18.7.3** Boilers and pressure vessels shall be commissioned in accordance with the ASME *Boiler and Pressure Vessel Code*.

N **18.7.4*** Control systems and related instrumentation shall be commissioned in accordance with recognized standards.

18.8 Transfer of LNG and Flammables.

18.8.1 Where bulk transfers are made into stationary storage containers, the LNG being transferred shall be compatible in composition or in temperature and density with the LNG already in the container.

18.8.2 Where the composition or the temperature and density are not compatible, means shall be taken to prevent stratification and vapor evolution that could cause rollover.

18.8.3 Where a mixing nozzle or agitation system is provided, it shall be designed to prevent rollover.

18.8.4 At least one qualified person shall be in constant attendance while a transfer is in progress.

18.8.5 Sources of ignition shall not be permitted in loading or unloading areas while transfer is in progress.

18.8.6 Loading and Unloading Tank Vehicle, Tank Car, and ISO Container.

18.8.6.1 Sources of ignition shall not be allowed in loading or unloading areas while transfer is in progress.

18.8.6.2 Loading and unloading areas shall be posted with signs that read "No Smoking."

18.8.6.3 Where multiple products are loaded or unloaded at the same location, loading arms, hoses, or manifolds shall be identified or marked to indicate the product or products to be handled by each system.

18.8.6.4 Prior to transfer, gauge readings shall be obtained or inventory established to ensure that the receiving container cannot be overfilled, and levels shall be checked during transfer operations.

18.8.6.5 The transfer system shall be checked prior to use to ensure that valves are in the correct position.

18.8.6.6 Transfer operations shall be commenced slowly and if any unusual variance in pressure or temperature occurs, transfer shall be stopped until the cause has been determined and corrected.

18.8.6.7 Pressure and temperature conditions shall be monitored during the transfer operation.

18.8.6.8 While tank car, tank vehicle, or ISO container loading or unloading operations are in progress, rail and vehicle traffic shall be prohibited within 25 ft (7.6 m) of LNG facilities or within 50 ft (15 m) of refrigerants whose vapors are heavier than air.

18.8.6.8.1 Before a tank car is connected, the car shall be checked and the brakes set, the derailer or switch properly positioned, and warning signs or lights placed as required.

18.8.6.8.2 The warning signs or lights shall not be removed or reset until the transfer is completed and the car disconnected.

18.8.6.8.3 Truck vehicle engines shall be shut off if they are not required for transfer operations.

18.8.6.8.4 Brakes shall be set and wheels chocked prior to connection for unloading or loading.

18.8.6.8.5 The engine shall not be started until the truck vehicle has been disconnected and any released vapors have dissipated.

18.8.6.9 Oxygen Content.

18.8.6.9.1 Before LNG or flammable or combustible fluids are loaded into a tank car, tank vehicle, or ISO container that is not in exclusive service for that fluid, a test shall be made to determine the oxygen content in the container.

18.8.6.9.2 If the oxygen content exceeds 2 percent by volume, the container shall not be loaded until it has been purged to below 2 percent oxygen by volume.

18.8.6.9.3 If a tank car, tank vehicle, or ISO container in exclusive liquefied gas service does not contain a positive pressure, it shall be tested for oxygen content.

18.8.6.10 Before loading or unloading, a tank vehicle shall be positioned so it can exit the area without backing up, when the transfer operation is complete.

18.8.6.11 Tank cars and tank vehicles that are top-loaded through an open dome shall be bonded electrically to the fill piping or grounded before the dome is opened.

18.8.6.12 Communications shall be provided at loading and unloading locations so that the operator can be in contact with other remotely located personnel who are associated with the loading or unloading operation.

18.8.7 Marine Shipping and Receiving.

18.8.7.1 Vessel Arrival.

18.8.7.1.1 The requirements of 18.4.7 shall be communicated to the vessel operator to facilitate safe vessel berthing and unberthing.

18.8.7.1.2 Warning signs or barricades shall be used to indicate that transfer operations are in progress.

18.8.7.1.3 A vessel-specific mooring plan utilizing the criteria developed in 15.5.1 shall be developed for each ship calling at the waterfront facility.

18.8.7.1.4 The vessel shall be moored in a safe and effective manner.

18.8.7.1.5 The terminal operator shall certify in writing that the provisions of 18.11.5.1 and 18.11.5.3 are met.

18.8.7.1.6 This certification shall be available for inspection at the waterfront facility that handles LNG.

18.8.7.2 Prior to Transfer.

18.8.7.2.1 Before transferring LNG, the facility shall do the following:

(1) Inspect the transfer piping and equipment to be used during the transfer and replace any worn or inoperable parts
(2) Note the pressure, temperature, and volume to ensure they are safe for transfer for each of the vessel's cargo tanks from which cargo will be transferred
(3) Review and agree with the vessel operator on the sequence of transfer operations
(4) Review and agree with the vessel operator on the transfer rate
(5) Review and agree with the vessel operator on the duties, location, and watches of each person assigned for transfer operations
(6) Review emergency procedures from the emergency manual
(7) Review and agree with the vessel operator on means (dedicated channels, etc.) of maintaining a direct communication link between the watches on the ship and shoreside throughout the cargo transfer
(8) Ensure that transfer connections allow the vessel to move to the limits of its moorings without exceeding the normal operating envelope of the loading arms
(9) Ensure that each part of the transfer system is aligned to allow the flow of LNG to the desired location
(10) Verify that the cargo liquid and vapor lines on the vessel, the loading arms, and the shoreside piping systems have been purged of oxygen
(11) Ensure that warning signs that warn that LNG is being transferred are displayed
(12) Verify that no source of ignition exists in the marine transfer area for LNG
(13) Ensure that personnel are on duty in accordance with the operations manual
(14) Test the sensing and alarm systems, the emergency shutdown system, and the communication systems to determine that they are operable

18.8.7.2.2 Prior to transfer, the officer in charge of vessel cargo transfer and the person in charge of the shore terminal shall inspect their respective facilities to ensure that transfer equipment is in operating condition.

18.8.7.2.3 Following the inspection described in 18.8.7.2.2, the officer in charge of vessel cargo transfer and the person in charge of the shore terminal shall meet and determine the transfer procedure, verify that ship-to-shore communications exist, and review emergency procedures.

18.8.7.2.4 After the pretransfer inspection required by 18.8.7.2.1 has been satisfactorily completed, there shall be no transfer of LNG until a declaration of inspection that demonstrates full compliance with 18.8.7.2.2 is executed and signed.

18.8.7.2.4.1 One signed copy of the declaration of inspection shall be given to the person in charge of transfer operations on the vessel, and one signed copy shall be retained for 30 days after completion of the transfer at the waterfront facility that handles LNG.

 Shaded text = Revisions. Δ = Text deletions and figure/table revisions. • = Section deletions. *N* = New material.

18.8.7.2.4.2 Each declaration of inspection shall contain the following:

(1) The name of the vessel and the waterfront facility that handles LNG
(2) The dates and times that transfer operations began and ended
(3) The signature of the person in charge of shoreside transfer operations and the date and time of signing, indicating that he or she is ready to begin transfer operations
(4) The signature of each relief person in charge and the date and time of each relief
(5) The signature of the person in charge of shoreside transfer operations and the date and time of signing, indicating that the marine transfer has been completed

18.8.7.2.5 The communication system required in 15.9.3 shall be continuously monitored both aboard ship and at the terminal.

18.8.7.3 Marine Connections.

18.8.7.3.1 When loading arms are connected for marine loading or unloading operations, all bolt holes in a flange shall be utilized for the connection.

18.8.7.3.2 Blind flanges shall be utilized on those arms not engaged in loading or unloading operations.

18.8.7.3.3 All connections shall be leaktight and tested prior to operation.

18.8.7.3.4 Marine loading or unloading arms shall be purged prior to use and purged and completely drained upon completion of transfer.

18.8.7.3.5 Marine loading or unloading operations shall be at atmospheric pressure when the arm(s) are connected or disconnected.

18.8.7.4* Transfer Operations in Progress.

18.8.7.4.1 Vehicle traffic shall be prohibited on the pier or dock within 100 ft (30 m) of the loading and unloading manifold while transfer operations are in progress.

18.8.7.4.2 Warning signs or barricades shall be used to indicate that transfer operations are in progress.

18.8.7.4.3* There shall be two independent means of egress, including emergency egress, from the ship.

18.8.7.4.4 During transfer of a ship's stores, including nitrogen, personnel involved in the transfer of a ship's stores shall not have simultaneous responsibility involved in the transfer of LNG.

18.8.7.4.5 Sources of ignition shall not be permitted in the marine transfer area while transfer is in progress.

18.8.7.4.6 General cargo, other than ships' stores for the LNG marine vessel, shall not be handled over a pier or dock within 100 ft (30 m) of the point where connections are made for LNG, and flammable fluids transfer while LNG or flammable fluids are being transferred through piping systems.

18.8.7.5 Bunkering Operations.

18.8.7.5.1 Bunkering operations shall be in accordance with any requirements established by the authority having jurisdiction over vessels or terminals.

18.8.7.5.2 During bunkering operations, the following shall apply:

(1) Personnel performing bunkering operations shall not have simultaneous responsibility for the transfer of LNG as cargo.
(2) No vessels shall be moored alongside the LNG vessel without the permission of the authority having jurisdiction.

18.9 Maintenance Manual.

18.9.1* Each operating company shall have a documented plan that sets out inspection and maintenance program requirements for each component, including fire protection and hazard detection, used in its LNG facility that is identified as requiring inspection and maintenance.

18.9.2 Each maintenance program shall be conducted in accordance with its documented plan for LNG facility components identified in the plan as requiring inspection and maintenance.

18.9.3 Each operating company shall perform the periodic inspections, tests, or both, on a schedule that is included in the maintenance plan on identified components and its support system identified as requiring inspection and maintenance that is in service in its LNG facility.

18.9.4 The maintenance manual shall refer to maintenance procedures, including procedures for the safety of personnel and property while repairs are carried out, regardless of whether the equipment is in operation.

18.9.5 The maintenance manual shall include the following for LNG facility components:

(1) The manner of carrying out and the frequency of inspections and tests
(2) A description of any other action, in addition to those referred to in 18.9.5, that is necessary to maintain the LNG facility in accordance with this standard
(3) All procedures to be followed during repairs on a component that is operating while it is being repaired, to ensure the safety of persons and property at the LNG plant

18.9.6 Procedures for the inspection of all pipe-in-pipe components, including vacuum levels, shall be specified and demonstrated to be appropriate for the installed condition.

18.9.7 Procedures for the repair and maintenance of all pipe in pipe components, including vacuum levels, shall be specified and demonstrated to be appropriate for the installed condition.

18.10 Maintenance.

18.10.1 Each operating company shall ensure that components in its LNG facility that could accumulate combustible mixtures are purged in accordance with 18.6.5 after being taken out of service and before being returned to service.

18.10.2 Where the operation of a component that is taken out of service could cause a hazardous condition, a tag bearing the words "Do Not Operate," or the equivalent, shall be attached to the controls of the component, or the component shall be locked out.

18.10.3 Foundation.

18.10.3.1 The support system or foundation of each component shall be inspected at least annually.

18.10.3.2 If the foundation is found to be incapable of supporting the component, it shall be repaired.

18.10.4 Emergency Power. Each emergency power source at the LNG plant shall be tested monthly to ensure that it is operational. Annual testing of the emergency power source shall also be conducted to ensure that it is capable of performing at its documented intended capacity, taking into account the power required to start some and simultaneously operate other equipment that would be served by the power source in a plant emergency.

18.10.5 Insulation systems for impounding surfaces shall be inspected annually.

18.10.6 Hoses for LNG and refrigerant transfer shall be tested at least annually to the maximum pump pressure or relief valve setting and shall be inspected visually before each use for damage or defects.

18.10.7 Marine loading or unloading operations shall be periodically tested as required by the authority having jurisdiction.

18.10.8 Repairs. Repairs that are carried out on components of an LNG facility shall be carried out in a manner that ensures the following:

(1) That the integrity of the components is maintained, in accordance with this standard
(2) That components operate in a safe manner
(3) That the safety of personnel and property during a repair activity is maintained

Δ **18.10.9 Site Housekeeping.** Each operating company shall do the following:

(1) Keep the grounds of its LNG plant free from rubbish, debris, and other materials that could present a fire hazard
(2) Ensure that the presence of foreign material contaminants, snow, or ice is avoided or controlled to maintain the operational safety of each LNG facility component
(3) Maintain the grassed area of its LNG plant so that it does not create a fire hazard
(4) Ensure that fire control access routes within its LNG plant are unobstructed and reasonably maintained in all weather conditions

18.10.10 Control Systems, Inspection, and Testing.

18.10.10.1 Each operating company shall ensure that a control system that is out of service for 30 days or more is tested prior to returning it to service, to ensure that it is in proper working order.

18.10.10.2 Each operating company shall ensure that the inspections and tests in this section are carried out at the intervals specified.

18.10.10.3* Control systems that are used seasonally shall be inspected and tested before use each season.

18.10.10.4 Control systems that are used as part of the fire protection and hazard detection systems at the LNG facility shall be inspected and tested in accordance with the applicable fire code and conform to the following:

(1) Monitoring equipment shall be maintained in accordance with *NFPA 72* and NFPA 1221.
(2) Fire protection water systems shall be maintained in accordance with NFPA 13, NFPA 14, NFPA 15, NFPA 20, NFPA 22, NFPA 24, NFPA 25, NFPA 750, and NFPA 1962.
(3)* Portable or wheeled fire extinguishers suitable for gas fires shall be available at strategic locations, as determined in accordance with Chapter 16, within an LNG facility and on tank vehicles, and shall be maintained in accordance with NFPA 10.
(4) Fixed fire extinguishing systems and other fire control equipment shall be maintained in accordance with NFPA 11, NFPA 12, NFPA 12A, NFPA 16, NFPA 17, and NFPA 2001.
(5) Detection devices not covered by *NFPA 72* shall be tested and calibrated in accordance with manufacturer's instructions once each calendar year at intervals not greater than 15 months.

18.10.10.5 Control systems, other than those referred to in 18.10.10.3 and 18.10.10.4, shall be inspected and tested once each calendar year at intervals that do not exceed 15 months.

18.10.10.6 Stationary LNG container relief valves shall be inspected and set-point tested at least once every 2 calendar years, with intervals not exceeding 30 months, to ensure that each valve relieves at the proper setting.

18.10.10.7 All other relief valves protecting hazardous fluid components shall be randomly inspected and set-point tested at the intervals specified in 18.10.10.7.1 and 18.10.10.7.2.

N **18.10.10.7.1** Inspection intervals shall be in accordance with either of the following:

(1) In-service inspected annually of the external portions of the valve and its installation in accordance with Section 2 of ANSI/NB-23, *National Board Inspection Code, Part 2, Inspection*, on in-service inspection requirements for pressure relief devices, including listed conditions that can be observed on the valves externally
(2) In accordance with API 510, *Pressure Vessel Inspection Code: In-service Inspection, Rating, Repair, and Alteration*

N **18.10.10.7.2** Set-point testing intervals shall be in accordance with either of the following:

(1) At intervals not exceeding five years, plus three months
(2) At a frequency in accordance with API RP 576, *Inspection of Pressure-Relieving Devices*

18.10.10.8 Stop valves for isolating pressure or vacuum-relief valves shall be locked or sealed open.

18.10.10.9* Stop valves shall not be operated except by an authorized person.

18.10.10.10 An LNG container shall have no more than one stop valve closed at one time.

18.10.10.11 When a component is served by a single safety device and the safety device is taken out of service for maintenance or repair, the component shall also be taken out of service, unless safety is accomplished by an alternative means.

18.10.11 LNG Tank Systems.

N **18.10.11.1* General.** The external surfaces of LNG tank systems shall be inspected and tested as set out in the maintenance manual for the following:

(1) Inner and outer container leakage
(2) Soundness of insulation

(3) Tank system foundation heating, to ensure that the structural integrity or safety of the tank system is not affected
(4) Deterioration of the tank equipment due to environmental exposure

N **18.10.11.2* Concrete Tank Components for Double, Full, and Membrane Tank Systems.** Exposed surfaces of the outer containment structure for double, full, and membrane containment tank system shall be externally examined at least every 5 years or at anytime there are visible or suspected problems.

N **18.10.11.2.1** Exposed surfaces available for inspection shall be examined to detect signs of deterioration, spalled or damaged concrete, cracks, efflorescence or rain water seepage, or any other conditions that can impact the integrity.

N **18.10.11.2.2** Special attention shall be paid to the integrity of the post-tensioning horizontal and vertical tendon anchor pockets.

N **18.10.11.2.3** The location and severity of deterioration shall be recorded for comparison with subsequent inspection.

N **18.10.11.2.4** If examination shows reinforcement corrosion, cracking, deterioration of concrete, evidence of moist surfaces, or water seepage these areas shall be reviewed by a qualified licensed engineer experienced in the field, and appropriate remedial actions shall be taken based upon the engineering evaluation.

N **18.10.11.2.5** If engineering evaluation reveals that the extent of deterioration reduces structural capacity of the concrete structure, risk assessment shall be conducted to establish the repair time line.

N **18.10.11.2.6** Repairs shall be conducted on an immediate basis if deterioration of concrete increases possibility for the product release from the tank.

18.10.12 Meteorological and Geophysical Events.

18.10.12.1 LNG storage facilities and, in particular, the storage container and its foundation shall be externally inspected after each major meteorological disturbance to ensure that the structural integrity of the LNG facility is intact.

18.10.12.2 If a potentially damaging geophysical or meteorological event occurs, the following shall be accomplished:

(1) The plant shall be shut down as soon as is practical.
(2) The nature and extent of damage, if any, shall be determined.
(3) The plant shall not be restarted until operational safety is re-established.

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N **18.10.13 Corrosion Protection.**

N **18.10.13.1 Design and Installation.**

N **18.10.13.1.1** All metallic components (e.g., containers, piping, valves, vaporizers, heat exchangers, and so on) containing LNG and hazardous fluids (liquid or vapor state) that could have their integrity or reliability adversely affected by external, internal, or atmospheric corrosion during their intended service life shall be protected from corrosion.

N **18.10.13.1.2** The design and the installation procedure of external corrosion control cathodic protection systems shall be documented.

N **18.10.13.1.3** Components whose integrity or reliability could be adversely affected by corrosion shall be treated as follows:

(1) Protected from corrosion in accordance with 18.10.13.1 through 18.10.13.5, as applicable
(2) Inspected under a program of scheduled maintenance in accordance with 18.10.13.6 and 18.10.13.7

N **18.10.13.2 Atmospheric Corrosion Control.**

N **18.10.13.2.1** Each exposed component that is subject to atmospheric corrosion shall be protected from atmospheric corrosion by either of the following:

(1) A material that has been designed to resist the corrosive atmosphere involved
(2) Coating or jacketing suitable for the prevention of atmospheric corrosion

N **18.10.13.2.2** Where coatings are used, the component being coated shall be prepared to accept the coating and the coating shall be applied as required by the coating manufacturer to ensure performance of the coating.

N **18.10.13.3* External Corrosion Control: Buried or Submerged Components.**

N **18.10.13.3.1** Each buried or submerged component that is subject to external corrosion shall be protected from external corrosion by either of the following:

(1) Material that has been designed to resist the corrosive environment involved
(2) Both of the following means:
    (a)* An external protective coating designed for operating conditions and for the environmental conditions of the installation site, and installed to prevent corrosion of the protected component.
    (b)* A cathodic protection system (impressed current type or galvanic anode system) designed to protect components in their entirety in accordance with the following:
        (i) The cathodic protection system shall be controlled so as not to damage the component or its coating.
        (ii) Each component under cathodic protection shall be installed with test stations to determine the adequacy of the cathodic protection.
        (iii) Each test station shall have test leads installed that remain mechanically secure and electrically conductive; are attached to a component to minimize stress conditions on that component; and are coated with electrically insulating material compatible with the coating on the component.

N **18.10.13.3.1.1** Prior to installation, each container, length of pipe, and other components shall be visually inspected at the installation site to identify damage.

N **(A)** Damage to the container, pipe, or component that could impair its serviceability shall be repaired as permitted by pressure vessel, pipe, and component codes.

N **(B)** Any coating damage shall be repaired using materials compatible with the existing coating following the manufacturer's procedures.

N **18.10.13.3.1.2** Components shall be surrounded by earth or sand that is free of rocks and abrasives, and firmly tamped in place.

N **18.10.13.3.1.3** The portions of a partially underground, unmounded ASME container that are below the surface of the ground and for a vertical distance of at least 3 in. (75 mm) above that surface shall comply with 18.10.13.1. The remaining aboveground portion of the container shall be coated against atmospheric corrosion.

N **18.10.13.3.1.4** The part of an aboveground ASME container in contact with saddles or a foundation shall be provided a means to minimize corrosion.

N **18.10.13.3.2** Where cathodic protection is applied, components that are electrically interconnected shall be protected as a unit.

N **18.10.13.3.3** The requirements of 18.10.13.3 shall be installed and placed in operation within one year after completion of initial system installation.

N **18.10.13.3.3.1** The requirements of 18.10.13.3 shall not apply where technical documentation that a corrosive environment does not exist is approved by the AHJ.

N **(A)** The technical documentation shall be based on testing, investigation, or experience in the area of application.

N **(B)** The technical documentation shall include, as a minimum, soil resistivity measurements, and tests for corrosion accelerating bacteria.

N **18.10.13.3.3.2** Tests shall be required after six months of burial of the system identified in 18.10.13.3.1, including component-to-soil potential measurements with respect to either a continuous reference cell electrode or an electrode using close spacing, not to exceed 20 ft (6 m), and soil resistivity measurements at potential profile peak locations to evaluate the potential profile at the component or along the pipeline. If tests indicate that a corrosive condition exists, the affected components shall be cathodically protected in accordance with 18.10.13.

N **18.10.13.3.3.3** After the initial tests in 18.10.13.3.3.2, additional tests shall be conducted every three years and not exceeding 39 months to reevaluate the condition of the unprotected components. If tests indicate that an active corrosion exists either by electrical survey of leak repair or exposed pipe inspection records, the affected components shall be cathodically protected in accordance with 18.10.13.3.

N **18.10.13.3.4** Where insulating devices (e.g., flange, fitting, union) for cathodic protection are installed, precaution shall be taken to prevent arcing in areas where combustible atmospheres are anticipated.

N **18.10.13.3.5** Where components are located in close proximity to electric transmission tower footings, ground cables, or counterpoises, or in areas where fault currents or unusual risk of lightning is anticipated, they shall be provided with protection against damage due to fault currents or lightning, and protective measures shall be taken at insulating devices.

N **18.10.13.4 Internal Corrosion Control.** Each component that is subject to internal corrosive attack shall be protected from internal corrosion by one of the following:

(1) Material that has been designed to resist the corrosive fluid involved
(2) Coating, inhibitor, or other means

N **18.10.13.5 Interference Currents.**

N **18.10.13.5.1** Each component that is subject to electrical current interference shall be protected by a continuing program to minimize the detrimental effects of interference currents.

N **18.10.13.5.2** Each cathodic protection system shall be designed and installed so as to minimize any adverse effects it might cause to adjacent metal components.

N **18.10.13.5.3** Each impressed current power source shall be installed to prevent adverse interference with communications and control systems.

N **18.10.13.6 Monitoring Corrosion Control.** Corrosion protection shall be monitored to provide early recognition of ineffective corrosion protection, in accordance with 18.10.13.6.1 through 18.10.13.6.3.

N **18.10.13.6.1** Cathodic protection of buried or submerged components shall comply with the following:

(1) Cathodic protection systems installed in accordance with 18.10.13.3 shall be monitored by testing and the results documented and retained.
(2)* Cathodic protection system tests shall be described by producing a voltage of −0.80 volts or greater negative, with reference to a silver–silver chloride half-cell.
(3) Each buried or submerged component under cathodic protection shall be tested by personnel qualified to perform corrosion control monitoring at least once each calendar year, with intervals not exceeding 15 months, to determine whether the cathodic protection is performing as designed.
(4) Each cathodic protection rectifier or other impressed current power source shall be inspected by personnel qualified to perform corrosion control monitoring at least six times each calendar year, with intervals not exceeding two and a half months, to ensure that it is performing as designed.
(5) Each reverse current switch, each diode, and each interference bond whose failure would jeopardize component protection shall be electrically checked for proper performance at least six times each calendar year, with intervals not exceeding two and a half months, by personnel qualified to perform corrosion control monitoring. Other interference bonds shall be checked at least once each calendar year, with intervals not exceeding 15 months.
(6) Whenever any portion of a buried pipe is exposed, the exposed portion of the pipe shall be examined for evidence of external corrosion in either of the following instances:
    (a) If general external or localized external pitting corrosion is identified, additional examination in the exposed area shall be conducted to identify the extent of the corrosion.
    (b) If damage to the component coating is observed, the coating shall be repaired in accordance with 18.10.13.3.1.1(B).

N **18.10.13.6.2** Each component that is protected from atmospheric corrosion shall be inspected at intervals not exceeding three years.

N **18.10.13.6.2.1** Components located at soil-to-air interfaces, under disbonded coatings, at pipe supports, in splash zones, and deck penetrations shall be inspected.

N **18.10.13.6.2.2*** Components covered by insulation that are subject to atmospheric corrosion shall be periodically monitored in accordance with a written program based upon the principles of NACE SP 0198, *Control of Corrosion Under Insulation and Fireproofing Materials — A Systems Approach.*

N **18.10.13.6.3** Components that are protected from internal corrosion shall have monitoring devices designed to detect internal corrosion.

N **18.10.13.6.3.1** Monitoring devices shall be located where corrosion is most likely to occur.

N **18.10.13.6.3.2** Internal corrosion control monitoring devices shall be monitored at least two times each calendar year, with intervals not exceeding seven and a half months.

N **18.10.13.6.3.3** Monitoring shall not be required for corrosion-resistant materials if it is demonstrated that the component is not adversely affected by internal corrosion during its service life.

N **18.10.13.6.3.4** Whenever a pipe is opened, the internal surface shall be examined for evidence of corrosion.

N **18.10.13.7 Remedial Measures.** Corrective action shall be taken when inspection determines that atmospheric, external, or internal corrosion is not controlled in accordance with 18.10.13.

N **18.10.13.7.1*** Components observed during monitoring required per 18.10.13.6.1, 18.10.13.6.2, and 18.10.13.6.3 shall be replaced where uniform or localized corrosion, or localized corrosion pitting has resulted in a remaining wall thickness less than that required for the MAOP of the pipeline, or a remaining wall thickness less than 50 percent of the nominal wall thickness.

N **18.10.13.7.2** Where components are observed with atmospheric corrosion not exceeding values in 18.10.13.7.1, the coating shall be repaired in accordance with 18.10.13.3.1.1(B).

N **18.10.13.8 Retroactivity.**

N **18.10.13.8.1** All new plants shall meet all the requirements for corrosion control in 18.10.13.

N **18.10.13.8.2** All expanded, significantly modified plants, or plants replacing components containing LNG and hazardous fluids (liquid or vapor state) shall meet the requirements for corrosion control in 18.10.13 for expanded, modified, or replaced portions of the plant.

N **18.10.13.8.3** Corrosion control requirements shall be applied retroactively to existing plants in accordance with 18.10.13.8.3.1 through 18.10.13.8.3.3.

N **18.10.13.8.3.1** Atmospheric corrosion control requirements shall be applied to existing facilities in accordance with 18.10.13.8.3.1(A) and 18.10.13.8.3.1(B).

N **(A)** The following atmospheric corrosion control procedures shall be met within one year of the issuance of this standard:

(1) Coating of exposed components in accordance with 18.10.13.2.1(2)
(2) Monitoring in accordance with 18.10.13.6.2
(3) Remedial measures in accordance with 18.10.13.7
(4) Recordkeeping

N **(B)** The following procedures for components covered by thermal insulation or fireproofing materials shall be met within three years of issuance of this standard:

(1) Coating in accordance with 18.10.13.2.1(2)
(2) Monitoring in accordance with 18.10.13.6.2.2
(3) Remedial measures in accordance with 18.10.13.7
(4) Recordkeeping

N **18.10.13.8.3.2** The following procedures for internal corrosion control shall be met within one year of the issuance of this standard:

(1) Component monitoring in accordance with 18.10.13.6.3
(2) Remedial measures in accordance with 18.10.13.7
(3) Recordkeeping

N **18.10.13.8.3.3** The following procedures for external corrosion control of buried or submerged components shall be met within five years of the issuance of this standard:

(1) Install cathodic protection system in accordance with 18.10.13.1.2, 18.10.13.3.3, 18.10.13.3.4, 18.10.13.3.5, and 18.10.13.5
(2) Monitoring in accordance with 18.10.13.6.1
(3) Remedial measures in accordance with 18.10.13.7
(4) Recordkeeping

18.11 Personnel Training.

18.11.1 Every operating plant shall have a written training plan to instruct all LNG plant personnel.

Δ **18.11.2** The training plan shall include training of permanent maintenance, operating, and supervisory personnel with respect to the following:

(1) The basic operations carried out at the LNG facility
(2) The characteristics and potential hazards of LNG and other hazardous fluids involved in operating and maintaining the LNG plant, including the serious danger from frostbite that can result from contact with LNG or cold refrigerants, asphyxiants, flammability of mixtures with air, odorless vapors, boiloff characteristics, and reactions with water
(3) Methods of carrying out the duties of maintaining and operating the LNG plant as set out in the manual of operating and maintenance procedures referred to in Sections 18.3 and 18.9
(4) Methods of carrying out emergency procedures required by Section 18.4 as they relate to their assigned functions
(5) Personnel safety and general construction industry safety-related training as it relates to the assigned functions

N **18.11.2.1** All operating and appropriate supervisory personnel shall be trained in the following:

(1) Instructions on the facility operations, including controls, functions, and operating procedures
(2) LNG transfer procedures
(3) Purging practices and principles

N **18.11.2.2** All personnel involved in operation and maintenance of LNG plants, including immediate supervisors, shall be trained in the following aspects of fire protection and fire drills:

(1) Potential causes and areas of fire
(2) Types, sizes, and predictable consequences of fire
(3) Assigned fire control duties in accordance with the emergency procedures in Section 18.4, which includes proper use of fire protection and emergency response equipment
(4) Hands-on experience in carrying out duties as listed in the emergency procedures in Section 18.4

N **18.11.2.3** Personnel responsible for security as it relates to their assigned functions and described in the required security procedures shall be trained to do the following:

(1) Recognize security breaches
(2) Carry out security procedures as it relates to their assigned functions
(3) Be familiar with basic plant operations and emergency procedures as necessary to perform their assigned functions
(4) Identify situations where it would be necessary to obtain assistance to maintain the security of the LNG plant

18.11.3 All LNG plant personnel shall meet the following requirements:

(1) LNG plant personnel shall receive the training referred to in 18.11.2.
(2) LNG plant personnel shall have experience related to their assigned duties.

18.11.4 Any person who has not completed the training or received experience set out in 18.11.2 shall be under the control of trained personnel.

18.11.5 Marine Transfer Training. All persons involved in the marine transfer of LNG shall be thoroughly familiar with all aspects of the transfer procedure, including potential hazards and emergency procedures.

18.11.5.1 Training for personnel involved in the marine transfer of LNG shall include the following:

(1) LNG transfer procedures, including practical training under the supervision of a person with such experience as determined by the terminal operator
(2) The provisions of the contingency plan required in 18.4.7

18.11.5.2 Time spent assisting in the transfer shall fulfill this practical training requirement.

18.11.5.3 Each person involved in the shoreside transfer operations shall have been trained in accordance with the requirements of 18.11.2 and shall have the following:

(1) At least 48 hours of LNG transfer experience
(2) Knowledge of the hazards of LNG
(3) Familiarity with the provisions of Chapter 15
(4) Knowledge of the procedures in the terminal's operations manual and emergency manual

18.11.6 Refresher Training.

18.11.6.1 Persons who are required to receive the training in 18.11.2 or 18.11.5 shall receive refresher training in the same subjects at least once every 2 years.

18.11.6.2 Performing actual loading or unloading operations, under the observation of a qualified individual, shall fulfill the requirement for refreshing of practical training in 18.11.5.

18.12 Records.

18.12.1 Each operating company shall maintain for a period of not less than 5 years a record of the date and type of each maintenance activity performed on each component of the LNG facility, including a record of the date that a component is taken out of or placed into service.

18.12.2 Records shall be made available during business hours upon reasonable notice.

18.12.3 For the life of the LNG facility, each LNG facility operator shall maintain records of each test, survey, or inspection required by this standard in detail sufficient to demonstrate the adequacy of corrosion control measures.

18.12.4 A record of all training shall be maintained for each employee of an LNG facility, and the records shall be maintained for at least 2 years after the date that the employee ceases to be employed at the LNG facility.

Chapter 19 Performance-Based LNG Plant Siting Using Quantitative Risk Analysis (QRA)

19.1 Scope.

19.1.1 This chapter includes the calculation of individual and societal risks from a liquefied natural gas (LNG) plant, arising from potential releases of LNG and other hazardous substances stored, transferred, or handled in the plant.

19.1.2 Where approved, the requirements of this chapter shall be permitted to replace Chapter 5 of this standard. The requirements in Chapter 5 and Chapter 19 shall not be combined.

19.1.3 The provisions of this chapter shall be applied to newly proposed facilities and existing facilities where significant modifications and improvements are proposed. The requirements of this chapter shall be applied to the entire plant.

19.1.4 Risks from transportation accidents outside the plant boundary that could impact the plant shall be quantified.

N **19.1.5** Risks from transportation accidents within the plant boundary that could impact plant safety shall be quantified.

19.2 General Requirements.

19.2.1* All inputs, assumptions, methodologies, and risk assessments to be utilized within the QRA shall be fully documented and approved.

Δ **19.2.2*** The requirements of this chapter shall be used at the time of siting to quantify individual and societal level of risks to ensure that they meet the tolerability criteria in accordance with Section 19.9.

19.2.3 The risk associated with an existing plant shall be requantified for siting when conditions change as a direct consequence of actions and significant modifications undertaken by the plant.

N **19.2.4** The QRA shall be reassessed every five years or as required by the AHJ for coordinating emergency response procedures in accordance with 18.4.5.

19.3 Definitions. The following definitions shall apply only to usage in Chapter 19.

19.3.1* As Low as Reasonably Practicable (ALARP). The level of risk that represents the point, objectively assessed, at which the time, difficulty and cost of further reduction measures become unreasonably disproportionate to the additional risk reduction obtained.

19.3.2 Event. The combination of successive outcomes of LNG or hazardous material releases and their subsequent hazard to persons exposed.

19.3.3 Individual Risk. The frequency, expressed in number of realizations per year, at which an individual, with continuous potential exposure, can be expected to sustain fatal injury; and irreversible harm if required by the AHJ.

19.3.4 Societal Risk. The cumulative risk exposure by all persons sustaining fatal injury and, if required by the AHJ, irreversible harm from an event in the LNG plant.

19.4 Risk Calculations and Basis of Assessment.

Δ **19.4.1** Individual risks shall be presented in the form of contours of constant individual risk values.

N **19.4.2** Societal risk shall be presented in the form of a diagram of cumulative annual frequency and the number of exposed persons.

19.4.3 Risks calculated shall be compared with values of risks to which the population in the general vicinity of the proposed/existing plant may be subject due to natural causes or from other human activities.

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19.5 LNG and Other Hazardous Materials Release Scenarios.

19.5.1 Release Scenario Selection.

N **19.5.1.1** A comprehensive set of LNG and other hazardous material release scenarios from storage containers, process systems, and transfer areas shall be developed.

N **19.5.1.2*** A list of hazard scenarios shall be informed through the use of a process hazard analysis (PHA).

19.5.2 Release Scenario Specifications.

19.5.2.1 The following shall be specified for each LNG and hazardous material release scenario, as applicable:

(1) Stream composition
(2) Nominal stream pressure and temperature
(3) Physical state of the fluid
(4) Sectionable inventory
(5) Hole size(s)
(6) Release location(s) and direction(s)
(7) Release duration for successful and unsuccessful isolated inventories

N **19.5.2.1.1** The release flow rate for each scenario shall take into account pump runout, the phase of the fluid, and other applicable phenomena.

N **19.5.2.1.2** The annual probability of occurrence shall be specified for each scenario, in accordance with the requirements in Section 19.6.

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19.5.2.2 The thermal and physical characteristics of the substrate exposed to a liquid release shall be specified and accounted for in the consequence modeling for that scenario.

19.5.2.3 The spectrum of hazardous behavior of the released fluid due to its interaction with the substrate, the environment, and natural tendencies shall be considered and documented. The behavior modes that shall be considered include, but are not limited to, flashing, aerosol formation, liquid jetting, pool formation and flow, dispersion of vapors, jet fires, flash fires, vapor cloud explosions, fireballs, pool fires, pressure vessel bursts, and BLEVES.

19.6 Release Probabilities and Conditional Probabilities.

Δ **19.6.1*** The annual probability of LNG and other hazardous material releases from various equipment for scenarios identified in Section 19.5 shall be based on Table 19.6.1 or as approved by the AHJ.

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19.6.2* Conditional probabilities applied to the analysis shall be justified and documented.

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19.7 Modeling Conditions and Occurrence Probabilities.

19.7.1* Site-specific weather data shall be gathered either by direct measurements at the site for periods of time acceptable to obtain statistically meaningful data or from the most representative meteorological station. The data collection and averaging periods shall be approved.

N **19.7.1.1*** The weather data shall include the following:

(1) Wind direction
(2) Wind speed
(3) Ambient temperature
(4) Relative humidity

N **19.7.1.2** If weather data is not available that is representative of the site, an approved set of conservative assumptions shall be used.

19.7.2 Conditional probabilities for environmental conditions shall be obtained from the weather data as specified in 19.7.1.

Δ **19.7.3*** Topographic and structural features within and in proximity of the plant site that increase the consequences of the release scenarios shall be included in the assessment of hazards.

N **19.7.3.1** For vapor cloud explosions, confinement and congestion due to piping, equipment, and vegetation shall be considered.

Δ **19.7.4** The locations and characteristics of ignition sources in and around the plant shall be assessed and documented.

N **19.7.5*** The probabilities of ignition sources being active during the dispersion of a vapor cloud shall be assessed and documented.

19.8 Hazard and Consequence Assessment.

19.8.1 The hazard footprints of release scenarios identified pursuant to the requirements in Section 19.5 shall be calculated.

Δ **19.8.2*** Hazard footprints shall be quantified for each combination of release scenario, type of hazard, and environmental and plant operating condition, identified pursuant to the requirements of Sections 19.5, 19.6, and 19.7.

N **Table 19.6.1 Failure Rate Database**

Type of Failure	Failure Rate Per Year of Operation
Single-Containment Atmospheric Storage Tank System	
Catastrophic failure	1E-6 per tank system*
Catastrophic failure of tank system roof (steel roof only)	1E-4 per tank system
Double-Containment Atmospheric Storage Tank System	
Catastrophic failure	1.25 E-8 per tank system*
Catastrophic failure of tank system roof (steel roof only)	1E-4 per tank system
Full-Containment and Membrane Atmospheric Storage Tanks System (Concrete Outer Container)	
Catastrophic failure	1E-8 per tank system*
Catastrophic failure of tank system roof (steel roof only)	4E-5 per tank system
Membrane-Containment Atmospheric Storage Tanks System (Concrete Outer Container)	
Catastrophic failure	1E-8 per tank system*
Catastrophic failure of tank system roof (steel roof only)	4E-5 per tank system
Other Atmospheric Storage Tanks	
Catastrophic failure	3E-6 per tank
Product release from a hole with effective diameter of 12 in. (300 mm)	2.5E-3 per tank
Product release from a hole with effective diameter of 36 in. (1000 mm)	1E-4 per tank
Catastrophic failure of tank roof	2E-3 per tank
Pressurized Storage Vessels	
Catastrophic failure (i.e., rupture)	5E-7 per vessel
Catastrophic failure of vessel fabricated according to 8.5.1.5	1E-8* a per vessel
Release from a hole with effective diameter of 0.4 in. (10 mm)	1E-5 per vessel
Process Vessels, Distillation Columns, Heat Exchangers, and Condensers	
Catastrophic failure (i.e., rupture)	5E-6 per vessel
Release from a hole with effective diameter of 0.4 in. (10 mm)	1E-4 per vessel
Truck Transfer	
Rupture of transfer arm	3E-4 per transfer arm
Release from a hole in transfer arm with effective diameter of 10% of the transfer arm diameter with maximum of 2 in. (50 mm)	3E-3 per transfer arm
Rupture of transfer hose	4E-2 per transfer hose
Release from a hole in transfer hose with effective diameter of 10% of the transfer hose diameter with maximum of 2 in. (50 mm)	4E-1 per transfer hose
Ship Transfer	
Rupture of transfer arm	2E-5 per transfer arm
Release from a hole in transfer arm with effective diameter of 10% of the transfer arm diameter with maximum of 2 in. (50 mm)	2E-4 per transfer arm
Piping (General)†	
Rupture at valve	9E-6 per valve
Rupture at expansion joint	4E-3 per expansion joint
Failure of gasket	3E-2 per gasket
Piping: d < 2 in. (50 mm)	
Catastrophic rupture	1E-6 per meter of piping
Release from a hole with effective diameter of 1 in. (25 mm)	5E-6 per meter of piping
Piping: 2 in. (50 mm) ≤ d < 6 in. (149 mm)	
Catastrophic rupture	5E-7 per meter of piping
Release from a hole with effective diameter of 1 in. (25 mm)	2E-6 per meter of piping

(continues)

N **Table 19.6.1** *Continued*

Type of Failure	Failure Rate Per Year of Operation
Piping: 6 in. (150 mm) ≤ d < 12 in. (299 mm)	
Catastrophic rupture	2E-7 per meter of piping
Release from a hole equivalent to ⅓ of the pipe diameter	4E-7 per meter of piping
Release from a hole with effective diameter of 1 in. (25 mm)	7E-7 per meter of piping
Piping: 12 in. (300 mm) ≤ d < 20 in. (499 mm)	
Catastrophic rupture	7E-8 per meter of piping
Release from a hole equivalent to ⅓ of the pipe diameter	2E-7 per meter of piping
Release from a hole equivalent to 10% of the pipe diameter, up to 2 in. (50 mm)	4E-7 per meter of piping
Release from a hole with effective diameter of 1 in. (25 mm)	5E-7 per meter of piping
Piping: 20 in. (500 mm) ≤ d < (40 in. (1000 mm)	
Catastrophic rupture	2E-8 per meter of piping
Release from a hole equivalent to ⅓ of the pipe diameter	1E-7 per meter of piping
Release from a hole equivalent to 10% of the pipe diameter, up to 2 in. (50 mm)	2E-7 per meter of piping
Release from a hole with effective diameter of 1 in. (25 mm)	4E-7 per meter of piping

*Consider effects due to external hazards when determining failure frequency.
†Consider distribution of hole sizes using total failure frequency in table.

19.8.3* The following types of hazard footprints shall be evaluated to quantify potentially fatal effects or, if required by the AHJ, irreversible harm:

(1) Concentration endpoints arising from flammable gas or vapor dispersion
(2) Concentration endpoints arising from toxic or oxygen-depriving gas or vapor dispersion
(3) Overpressure endpoints arising from vapor cloud explosions, pressure vessel bursts, and BLEVEs
(4) Heat flux or heat dosage endpoints arising from pool fires, jet fires, and fireballs

19.8.3.1 Potential cascading damages from primary release scenarios identified in Section 19.5 within the plant boundaries shall be assessed. If the assessment identifies an exacerbation of the initial hazards, the risk calculation shall include the cascading effects.

19.8.4 The hazard footprints for the types of hazards specified in 19.8.3 shall be calculated using approved models in accordance with 19.8.4.1 through 19.8.4.3.

Δ **19.8.4.1*** Hazard footprints for vapor cloud dispersion shall be calculated using models that meet the criteria specified in 5.3.2.7 or any other models that are acceptable to the AHJ.

N **19.8.4.1.1*** Threshold hazard values for vapor cloud dispersion shall be as specified in Table 19.8.4.1.1.

Δ **19.8.4.2** Hazard footprints for radiant heat flux and modified thermal dosage shall be calculated with models that meet the criteria specified in 5.3.2.8 or any other models that are acceptable to the AHJ.

N **19.8.4.2.1** Threshold hazard values for radiant heat flux shall be as specified in Table 19.8.4.2.1.

Table 19.8.4.1.1 Vapor Dispersion Consequence Endpoints

Concentration of released material in air	Duration	Consequence
LFL	N/A	Irreversible harm to and fatality of persons within an ignited flammable gas or vapor cloud
AEGL-3	Based on duration of exposure, but no more than 1 hour	Fatality of persons within a toxic gas cloud
AEGL-2	Based on duration of exposure, but no more than 1 hour	Irreversible harm to persons within a toxic gas cloud
40%	N/A	Fatality of persons within a gas cloud that displaces air to less than 12.5% oxygen
23%	N/A	Irreversible harm to persons within a gas cloud that displaces air to less than 16% oxygen

N/A: Not applicable.

Table 19.8.4.2.1 Radiant Heat Flux Consequence Endpoints

Maximum Heat Flux Level		
Btu/hr/ft^2	(kW/m^2)	Consequences
3000	9	Fatality of persons outdoors without personal protective equipment (PPE)
1600	5	Irreversible harm to persons outdoors without PPE
8000	25	Irreversible harm to and fatality of persons inside a building with a combustible exterior*.
10,000	30	Irreversible harm to and fatality of persons inside a building with a noncombustible exterior.

*Examples of combustible exteriors include wood-framed structures, asphalt shingles, vegetation, and so on.

N **19.8.4.2.2** For fireballs, the exposure extent shall be calculated using a dose equivalent to 3000 Btu/hr/ft^2 and 30 second exposure time (1.3 × 106 (Btu/hr/ft^2)$^{4/3}$s)

Δ **19.8.4.3** Hazard footprints for overpressures shall be calculated with models that meet the criteria specified in 5.3.2.8 or any other models that are acceptable to the AHJ.

N **19.8.4.3.1*** Threshold hazard values for overpressures shall be as specified in Table 19.8.4.3.1.

N **19.8.4.3.2** For BLEVEs or pressure vessel bursts, the exposure to projectile impact shall be considered using a kinetic energy threshold of 11 ft-lbf for persons outdoors, and 11 ft-lbf or a higher approved value for persons indoors.

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19.8.5 For each identified scenario of release and type of hazard identified in Section 19.5 and hazard impacts evaluated in Section 19.8, the total number of persons located within each unique hazard footprint shall be enumerated using public demographic or census data or other methodology approved by the AHJ.

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19.9 Risk Result Presentation.

19.9.1 Location-Specific Individual Risk.

Δ **19.9.1.1** The hazard footprint of each event shall be combined with its probability of occurrence and associated conditional probabilities to calculate the risk to an individual from that unique event.

19.9.1.2 The risk from each event in the QRA shall be combined to quantify the overall risk to an individual.

Table 19.8.4.3.1 Overpressure Consequence Endpoints

Side On Overpressure (psi)	Consequence
3.0	Fatality of persons outdoors
1.0	Irreversible harm of persons outdoors
1.0	Irreversible harm to and fatality of persons inside a building that is not blast resistant

19.9.1.3 The individual risk shall be displayed graphically using isopleths of constant individual risk.

19.9.1.4 The uncertainty and assumptions in calculating the individual risks shall be discussed.

19.9.2 Societal Risks.

Δ **19.9.2.1** The potential number of affected persons shall be determined using approved local demographic data and the calculated hazard footprints.

19.9.2.2 The societal risk values shall be presented in the form of cumulative annual frequency (F) of exceedance vs. number of affected persons (N). The F-N curve shall be constructed with all unique events evaluated in the QRA and their respective frequency of occurrence.

19.9.2.3 The uncertainty and assumptions in calculating the societal risks shall be discussed.

19.10 Risk Tolerability Criteria.

19.10.1 Individual risk acceptability criteria specified in Table 19.10.1(a) and Table 19.10.1(b) shall be used.

Δ **19.10.2*** The societal risk acceptability criteria specified in Figure 19.10.2(a) and Figure 19.10.2(b) shall be used.

Δ **19.10.3** The tolerability criteria used in 19.10.1 and 19.10.2 shall be permitted to be modified only with AHJ approval.

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Δ **Table 19.10.1(a) Criteria for Tolerability of Individual Risk (IR) of Fatality**

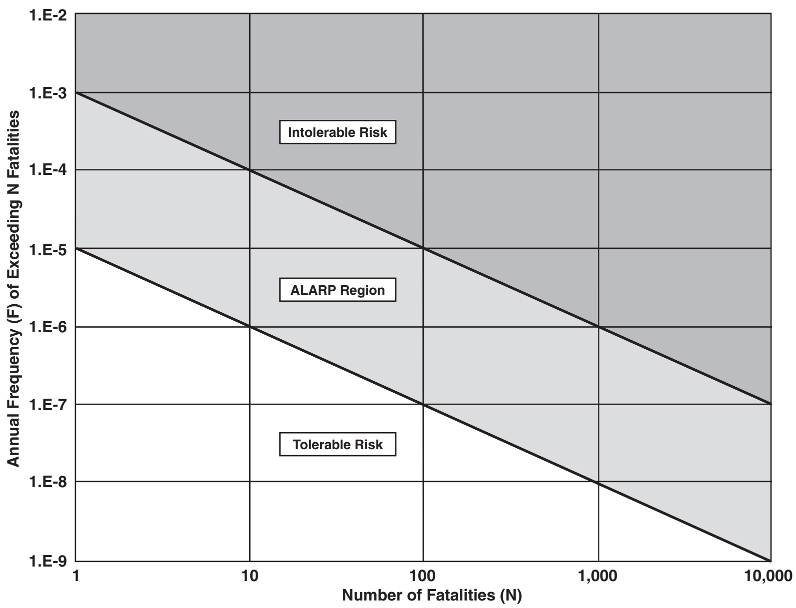
Criterion Annual Frequency	Permitted Developments
Zone 1 IR > 5×10^{-5}	All land uses under the control of the plant operator or subject to an approved legal agreement
Zone 2 $3 \times 10^{-7} \le$ IR $\le 5 \times 10^{-5}$	General public areas excluding sensitive establishments*
Zone 3 IR < 3×10^{-7}	No restrictions

*Sensitive establishments are institutional facilities that might be difficult to evacuate. Examples include, but are not limited to, schools, daycare facilities, hospitals, nursing homes, jails, and prisons.

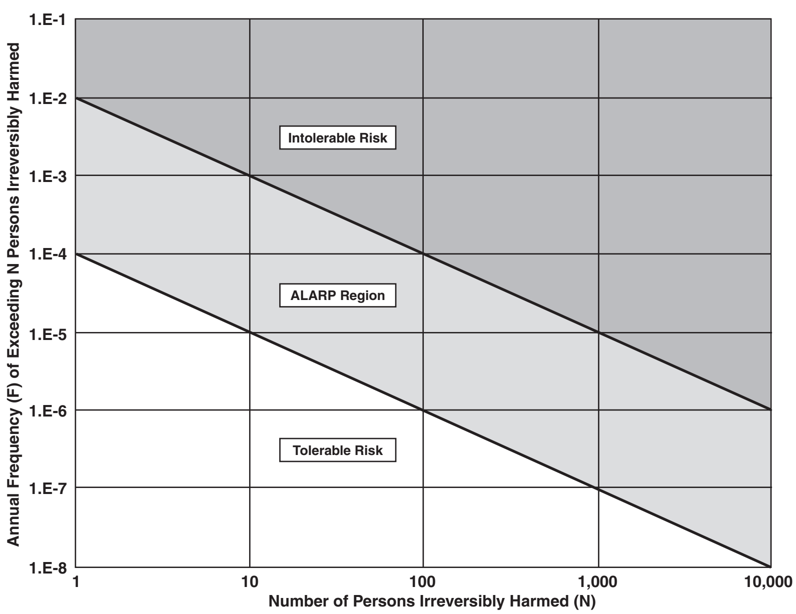
N **Table 19.10.1(b) Criteria for Tolerability of Individual Risk (IR) of Irreversible Harm**

Criterion Annual Frequency	Permitted Developments
Zone 1 IR > 5×10^{-4}	All land uses under the control of the plant operator or subject to an approved legal agreement
Zone 2 $3 \times 10^{-6} \le$ IR $\le 5 \times 10^{-4}$	General public areas excluding sensitive establishments*
Zone 3 IR < 3×10^{-6}	No restrictions

*Sensitive establishments are institutional facilities that might be difficult to evacuate. Examples include, but are not limited to, schools, daycare facilities, hospitals, nursing homes, jails, and prisons.



N **FIGURE 19.10.2(a) Tolerability Regions of Societal Fatality Risk in the F-N Domain.**



N **FIGURE 19.10.2(b) Tolerability Regions of Societal Irreversible Harm Risk in the F-N Domain.**

19.11 Risk Mitigation Approaches.

Δ **19.11.1*** Calculated individual risks in the unacceptable region shall be reduced to tolerable levels by implementing additional mitigation measures.

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N **19.11.2** Calculated societal risks in the unacceptable region shall be reduced to tolerable or ALARP levels by implementing additional approved mitigation measures.

N **19.11.3** In the case that the calculated societal risks lie in the ALARP region, risk reduction shall be considered by implementing additional approved mitigation measures.

Annex A Explanatory Material

Annex A is not a part of the requirements of this NFPA document but is included for informational purposes only. This annex contains explanatory material, numbered to correspond with the applicable text paragraphs.

A.1.1 This standard establishes essential requirements and standards for the design, installation, and safe operation of liquefied natural gas (LNG) facilities. It provides guidance to all persons concerned with the construction and operation equipment for the production, storage, and handling of LNG. It is not a design handbook, and competent engineering judgment is necessary for its proper use.

At sufficiently low temperatures, natural gas liquefies. At atmospheric pressure, natural gas can be liquefied by reducing its temperature to approximately −260°F (−162°C).

Upon release from the container to the atmosphere, LNG will vaporize and release gas that, at ambient temperature, has about 600 times the volume of the liquid. Generally, at temperatures below approximately −170°F (−112°C), the gas is heavier than ambient air at 60°F (15.6°C). However, as its temperature rises, it becomes lighter than air.

Note that the −260°F (−162°C) temperature value is for methane. If the other constituents are present, see 3.3.18. For information on the use of LNG as a vehicle fuel, see NFPA 52.

A.1.3 Departure from the requirements of this standard can be considered by the authority having jurisdiction on the basis of a risk assessment. In the case of such departures, approval will be contingent upon a demonstration of fitness for purpose in line with the principles of this standard and other applicable recognized standards as well as recognized and generally accepted good engineering practice.

A risk approach justification of alternatives can be applicable either to the LNG plant as a whole or to individual systems, subsystems, or components. The boundaries of the components and systems of the LNG plant to which a risk-based assessment is applied are to be logical. As appropriate, account must be given to remote hazards outside the bounds of the system under consideration. Such account must include incidents relating to remote hazards directly affecting or being influenced by the system under consideration. The authority having jurisdiction can consider the application of risk-based techniques in the design, construction, operation, and maintenance of the LNG plant.

Portions of the LNG plant not included in the risk assessment are to comply with the applicable parts of this standard.

Designers, fabricators, constructors, and operators requesting approval by the authority having jurisdiction are responsible for the following:

(1) Risk acceptance criteria
(2) Hazard identification
(3) Risk assessment
(4) Risk management

A.1.5 If a value for a measurement as given in this standard is followed by an equivalent value in other units, the first stated value should be regarded as the requirement. A given equivalent value should be considered to be approximate.

A.2.1 The intent of the committee is to adopt the latest edition of the referenced publications unless otherwise stated.

A.3.2.1 Approved. The National Fire Protection Association does not approve, inspect, or certify any installations, procedures, equipment, or materials; nor does it approve or evaluate testing laboratories. In determining the acceptability of installations, procedures, equipment, or materials, the authority having jurisdiction may base acceptance on compliance with NFPA or other appropriate standards. In the absence of such standards, said authority may require evidence of proper installation, procedure, or use. The authority having jurisdiction may also refer to the listings or labeling practices of an organization that is concerned with product evaluations and is thus in a position to determine compliance with appropriate standards for the current production of listed items.

A.3.2.2 Authority Having Jurisdiction (AHJ). The phrase "authority having jurisdiction," or its acronym AHJ, is used in NFPA documents in a broad manner, since jurisdictions and approval agencies vary, as do their responsibilities. Where public safety is primary, the authority having jurisdiction may be a federal, state, local, or other regional department or individual such as a fire chief; fire marshal; chief of a fire prevention bureau, labor department, or health department; building official; electrical inspector; or others having statutory authority. For insurance purposes, an insurance inspection department, rating bureau, or other insurance company representative may be the authority having jurisdiction. In many circumstances, the property owner or his or her designated agent assumes the role of the authority having jurisdiction; at government installations, the commanding officer or departmental official may be the authority having jurisdiction.

N **A.3.3.5** A container includes tanks, pressure vessels, portable tanks, tank cars and vehicles, and frozen ground storage.

A.3.3.5.4.1 Double-Containment Tank System. A double-containment tank system consists of a liquidtight and vaportight primary tank system, which is itself a single-containment tank system, built inside a liquidtight secondary liquid container. The primary liquid container is of low-temperature metal or prestressed concrete. The secondary liquid container is designed to hold all the liquid contents of the primary container in the event of leaks from the primary container, but it is not intended to contain or control any vapor resulting from product leakage from the primary container. The annular space between the primary container and the secondary container must not be more than 20 ft (6 m). The secondary liquid container is constructed either from metal or of prestressed concrete. Refer to API Std 625, *Tank Systems for Refrigerated Liquefied Gas Storage,* for further definition.

A.3.3.5.4.2 Full-Containment Tank System. A full-containment tank system consists of a liquidtight primary container and a liquidtight and vaportight secondary container. Both are capable of independently containing the product stored. The primary liquid container is of low-temperature metal or prestressed concrete. The secondary container must be capable of both containing the liquid product and controlling the vapor resulting from evaporation in the event of product leakage from the primary liquid container.

The secondary liquid container and roof are constructed either from metal or of prestressed concrete. Where concrete outer tanks are selected, vapor tightness during normal service must be ensured through the incorporation of a warm temperature vapor barrier. Under inner tank leakage (emergency) conditions, the material of the secondary concrete tank vapor barrier material will be exposed to cryogenic conditions. Vapor barrier liners are not expected to remain vaportight in this condition; however, the concrete must be designed to remain liquidtight and retain its liquid containment ability. Product losses due to the permeability of the concrete are acceptable in this case. For certain low temperature products, significant design issues arise at monolithically connected outer tank base-to-wall joints due to the mechanical restraint offered by the base. To mitigate these issues, it is normal practice to include a secondary liquid containment bottom and thermal corner protection to protect and thermally isolate this monolithic area from the cold liquid and provide liquid tightness.

Refer to API Std 625, *Tank Systems for Refrigerated Liquefied Gas Storage*, for further definition.

A.3.3.5.4.3 Membrane-Containment Tank System. A membrane-containment tank system consists of a thin metal liquid-tight barrier resting against load-bearing thermal insulation and supported by a free-standing outer container. The outer container and roof can be constructed either from prestressed concrete or of metal.

In normal conditions, primary liquid and vapor containment is provided by a thin metallic barrier that is structurally supported via load-bearing insulation on a self-standing outer container. Vapor containment is provided by either a thin metallic barrier supported by load-bearing insulation attached to the outer roof or thin metallic roof liner when concrete.

In emergency conditions, the secondary liquid and vapor containment is provided by an outer pre-stressed concrete container and metallic roof liner or by a cyrogenic metal container. The outer container must be capable of both containing the liquid product and controlling the vapor resulting from evaporation. In this instance, the vapor generated from the leakage is discharged through pressure relief valves located in the roof. Vapor losses due to permeability through the outer pre-stressed concrete are acceptable while the wall is containing liquid in the event of leakage from the thin metal barrier and insulation system.

The roof of an outer pre-stressed concrete container can be concrete or steel. Significant design issues arise at the monolithic base-to-wall connection of outer pre-stresed concrete container due to the mechanical restraint offered by the base. To mitigate these issues, a secondary liquid containment barrier inside the insulation system across the entire bottom and part of the wall in the vicinity of the base-to-wall joint is to be provided to protect and thermally isolate this area from the cold liquid and provide liquid-tightness. Other alternatives of the monolithic base-to-wall connection are described in ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases.*

A.3.3.5.4.4 Single-Containment Tank System. A single-containment tank system incorporates a liquidtight container and a vapor-tight container. It can be a liquidtight and vapor-tight single-wall tank or a tank system comprising an inner container and an outer container, designed and constructed so that only the inner container is required to be liquidtight and contain the liquid product. The outer container, if any, is primarily for the retention and protection of the insulation system from moisture and may hold the product vapor pressure, but it is not designed to contain the refrigerated liquid in the event of leakage from the inner container. The primary liquid container is constructed of low-temperature metal or prestressed concrete. The outer tank (if any) must be vapor-tight. It is normally made from carbon steel, and it is referenced in this standard in various contexts as the warm vapor container or the purge gas container. A single-containment tank system is surrounded by a secondary containment (normally a dike wall) that is designed to retain liquid in the event of leakage.

Refer to API Std 625, *Tank Systems for Refrigerated Liquefied Gas Storage*, for further definition.

A.3.3.9 Engineering Design. The engineering design conforms to regulatory requirements and includes all necessary specifications, drawings, and supporting documentation. The engineering design is developed from process, mechanical, civil, structural, fire protection, corrosion, control, and electrical requirements and other specifications.

The engineering design should be documented and include the following:

(1) Basis of design and criteria for the plant, facilities, and components
(2) Design and control philosophies for the plant, facilities, and components
(3) Codes, standards, and regulations to which the plant, facilities, and components are designed and constructed
(4) Process flow and utility flow diagrams
(5) Heat and material balances
(6) Piping and instrumentation diagrams using symbols consistent with ISA 5.1, *Instrumentation Symbols and Identification*
(7) Plot plan, unit plot plan, elevation drawings, three-dimensional drawings, or other set of drawings depicting plant and facility equipment layout
(8) Isometric drawings or other set of drawings depicting plant and facility piping and valve layout
(9) Piping, valve, and equipment lists
(10) Specifications and drawings for components
(11) Electrical single-line diagrams and load lists
(12) Loop diagrams and instrumentation lists or other documentation indicating wiring, calibration, and set points of instrumentation and controls consistent with ISA 5.4, *Instrument Loop Diagrams*
(13) Cause and effect matrices, logic ladders, or other documentation indicating causes and actions of emergency shutdown systems
(14) Relief valve and effluent handling sizing calculations and lists or other documentation indicating set points and sizing

(15) Spill containment, hazard detection, hazard control, and firewater layout drawings
(16) Other design-related information for plant, facilities, and components

A.3.3.12 Fire Protection. Fire protection covers measures directed at avoiding the inception of fire or the escalation of an incident following the accidental or inadvertent release of LNG and other flammables.

A.3.3.19 LNG Facility. The following describes the distinctions in the terms *component*, *LNG facility*, and *LNG plant*:

Several *components* (piping, flanges, fittings, valves including relief valves, gaskets, instrumentation, pumps, compressors, heat exchangers, motors, engines, turbines, electrical field wiring, etc.) installed and designed to function as one unit (storage, vaporization, liquefaction, transfer, etc.) are referred to as an *LNG facility*.

A collection of LNG facilities (storage, vaporization, liquefaction, transfer, etc.) co-located on a site is referred to as an *LNG plant*.

Components that function as a unit for purposes of serving an entire LNG plant (such as electrical systems, fire protection systems, security systems, etc.) can be referred to as LNG plant systems.

A.3.3.36 Transfer Area. Transfer areas do not include product sampling devices or permanent plant piping.

A.3.3.38 Vacuum-Jacketed. This is an insulating alternative for cryogenic piping and containers. If designed appropriately, this feature can satisfy the need for secondary containment for the inner piping.

A.3.3.39 Vaporizer. A pressure-building coil that is integral to a container is not considered to be a vaporizer in the context of NFPA 59A.

A.4.2 The terms *competence* and *competent* in this standard should be determined based on one of the following criteria:

(1) Documented training or certification from institutions or groups that test for knowledge, skill, and ability that relate to the science, technology, or engineering discipline for the facility or component
(2) Evidence of successful design, construction, operation, or use of a similar facility or component

Evidence to be considered should include but not be limited to the following:

(1) Work on similar facilities or components
(2) Date(s) that work was performed and completed
(3) Owner/operator contact information
(4) The amount of time the facility or component has been in operation
(5) Any substantive modifications to the original facility or component
(6) Satisfactory performance of the facility or component

The terms *competence* and *competent* in this standard should also be determined based on the evidence of knowledge, skill, and ability to do the following:

(1) Recognize an abnormal or flawed condition
(2) Respond accordingly to prevent an unsafe or hazardous condition from occurring or to correct such a condition at any stage of the construction or operation of the facility or component

A.4.2.1 See Appendix C of API Std 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*, for further information. In the United States, maps that delineate special flood hazard areas are maintained by local officials or can be ordered or viewed online at FEMA's Map Store at http://www.fema.gov. Accessibility to the plant can be limited during conditions of flooding. Flood loads are outlined in ASCE 7, *Minimum Design Loads and Associated Criteria for Buildings and Other Structures*. Structures, including tanks and containers, must be designed and constructed to prevent flotation, collapse, permanent lateral movement, and loss of contents during conditions of flooding.

A.4.3 Soil movement due to freezing of water is of two general types, as follows:

(1) The freezing of in situ water causes volumetric expansion of a moist soil.
(2) Frost heave is caused by migration of water to a zone of freezing and a continual growth of ice lenses.

A.4.5.4 Examples of nonstructural-slabs-on-grade (or slabs-on-ground) are slabs used for slope protection, impounding area paving, concrete aprons under piping and transfer areas, light truck and vehicle loading/unloading platforms, base slabs for outdoor mechanical or electrical equipment, base slabs for shop-built metal containers other than LNG containers, non–load transmitting ground floor slabs for enclosed mechanical/electrical rooms, non–load transmitting ground floor slabs for control rooms and office buildings, concrete-paved parking areas, garage floors, ground floor of storage buildings for light equipment and supplies, sidewalks, and pavements.

A.4.10 The provisions of Section 4.10 do not require inherently noncombustible materials to be tested in order to be classified as noncombustible materials. [***101,*** A.4.6.13]

A.4.10(1) Examples of such materials include steel, concrete, masonry, and glass. [***101,*** A.4.6.13.1(1)]

Δ **A.5.2** The following factors should be considered in the selection of plant site locations:

(1) Availability of land to accommodate the plant, including provisions for minimum clearances as stated in this standard between components and facilities with respect to each other and the degree that the LNG plant can separate facilities and components to allow for access and maintenance to equipment, reduce congestion, and protect personnel from accidental hazards
(2) Availability of infrastructure to construct and operate the plant, including pipelines; refrigerant, process, and utility makeup supplies; water, sewage, and electric utilities; road, marine, and rail transportation; and telecommunication systems
(3) Availability of personnel and support services to construct, operate, and maintain the plant, including qualified engineering firms and contractors, skilled craftsman, and site support facilities for housing, storage, and laydown
(4) Location of plant with respect to surrounding population, land use, infrastructure, cultural and historical sites, and development and the degree that the LNG plant can separate and protect the public from accidental hazards

(5) Location of plant with respect to emergency response and recovery facilities and the degree that the emergency response and recovery entities are equipped and capable of responding to potential incidents at the plant
(6) Location of plant with respect to security threats and vulnerabilities and the degree that the security forces are capable to deter, protect, and respond to potential security threats and incidents at the plant
(7) Site-specific meteorological and geological data and the degree that the LNG plant can be protected against natural hazards
(8) Site survey information for topography, bathymetry, and subsurface and subsea conditions
(9) Site-specific air, water, noise, luminosity, and other environmental and permitting requirements
(10) Other factors applicable to the specific site that have a bearing on the safety of personnel and the surrounding public, and the reliability, operability, and sustainability of the plant

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N **A.5.3.2.2** Methods that can be used to mitigate the effects of hazards include the following:

(1) Reducing the size, duration, or characteristics of the release or fire
(2) Impeding the dispersion or transmission of the hazard to the exposed objects
(3) Hardened structures and blast walls
(4) Other methods

N **A.5.3.2.3** For process vessels, the failures are associated with the piping connections to the vessel and not with the vessel shell itself.

N **A.5.3.2.6** For models used for flammable or toxic vapor dispersion from ground-based sources, evaluation using the Model Evaluation Protocol facilities published by the Fire Protection Research Foundation report "Evaluating Vapor Dispersion Models for Safety Analysis of LNG Facilities" should be applied.

N **A.5.3.2.9** There can be some uncertainty and limitations associated with current modeling programs. Models used to calculate LNG vapor dispersion hazards should be validated through an accepted model evaluation protocol (MEP). There are some modeling software programs that have been validated through a supplemented MEP by the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA). Those models that have been evaluated indicate an uncertainty factor of two should be applied (i.e., 50 percent LFL) when predicting dispersion distances to LFL.

N **A.5.3.2.13** The term *hazard footprint* is used to describe the area where hazardous conditions might occur as a result of a given accident. An example is the area where flammable vapor concentrations at or above the LFL might occur following the loss of containment in a pipe. Hazardous footprint is a more general term to replace the previously used "hazard distance," which recognizes the fact that the propagation of hazardous conditions from the source is generally not the same in all directions.

N **A.6.2.1** Examples include, but are not limited to, removal and servicing of equipment and instrumentation, heat exchanger tube bundle pulls, and overhead crane and crane truck use, and anticipated trucking or rail loading, unloading, and transport.

N **A.6.2.2** The layout and minimum separation distance between components and facilities should consider, where practical, separating the various facilities into units with different areas for facilities primarily containing hazardous fluids, facilities primarily containing non-hazardous fluids, and ignition sources.

N **A.6.4.2** Air intakes should be considered unless otherwise protected from gas ingestion.

N **A.6.6.3** Uncontrolled sources of ignition do not include vehicles associated with operations or maintenance activities.

N **A.6.6.4** Carbon structural steels (e.g., ASTM A36, *Standard Specification for Carbon Structural Steel;* structural sheet and plate; ASTM A53, *Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless;* and ASTM A106, *Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service;* carbon steel pipe) to begin to have a noticeable loss of strength at 570°F–650°F (300°C–350°C), lose approximately one-third of strength at 840°F–900°F (450°C–480°C), and lose approximately one-half of strength at 1000°F–1100°F (540°C–590°C). The temperatures associated with one-half and one-third losses of strength correspond to when structural steel begins to exceed allowable stresses and yield strengths and suffers possible structural damage based on allowable stress/strength designs in structural and mechanical design codes (e.g., ASCE 7, *Minimum Design Loads and Associated Criteria for Buildings and Other Structures;* AISC 360, *Specification for Structural Steel Buildings;* ASME B31.3, *Process Piping;* ASME *Boiler and Pressure Vessel Code*). In addition, this is consistent with Chapter 19 that limits temperatures to 570°F (300°C) based on one-half loss of structural strength for steel.

The temperatures associated with losses of strength would correspond to black body radiant heats (i.e., indefinite exposures with no heat losses) of approximately 2000 Btu/ft^2-hr (6.3 kW/m^2), 4900 Btu/ft^2-hr (15.5 kW/m^2), and 7750 Btu/ft^2-hr (24.5 kW/m^2), respectively. In addition, ABS (2006) reports indicate at approximately 8000 Btu/ft^2-hr (25.2 kW/m^2) steel can undergo substantial deformation and serious dislocation. Sandia (2004) indicates exposures to 10,000 Btu/ft^2-hr (37 kW/m^2) for 10 minutes would cause temperatures to rise to 980°F and result in 25–40 percent loss in steel strength and damage to the LNG marine carrier and other nearby steel structures.

Active and passive mitigation systems can mitigate the radiant heat or duration a LNG marine carrier. Common examples to mitigate impacts include spacing fire sources away to limit radiant heats, installing deluge systems to reduce heat impacts, and demonstrating emergency operations to move the LNG marine carrier by the crew or by tugs to limit exposure durations. Reliance on crew members or tugs to perform emergency actions to move the ship should consider the radiant heat and duration they are exposed. Other codes commonly limit people outfitted with personal protective equipment to perform emergency actions lasting a few to several minutes to exposures less than 1600 Btu/ft^2-hr because unprotected people could suffer second-degree burns within 30 seconds, and unprotected people would suffer fatal effects from exposures to 10,000 Btu/ft^2-hr for 30 seconds. Tugs with tow fire wires on the opposite side of a LNG marine carrier could be protected from radiant heat exposures.

A.7.3 API Std 617, *Centrifugal Compressors and Expander-compressors*; API Std 618, *Reciprocating Compressors for Petroleum,* *Chemical, and Gas Industry Services*; and API Std 619 *Rotary-Type Positive Displacement Compressors for Petroleum, Chemical, and Natural Gas Industry Services* provide guidance when selecting and specifying these types of compressors.

N **A.7.3.1** Examples of recognized standards include API Std 610, *Centrifugal Pumps for Petroleum, Petrochemical and Natural Gas Industries*; API Std 617, *Axial and Centrifugal Compressors and Expander-compressors*; API Std 618, *Reciprocating Compressors for Petroleum, Chemical, and Gas Industry Services*; API Std 619, *Rotary-Type Positive Displacement Compressors for Petroleum, Chemical, and Natural Gas Industry Services*; API Std 672, *Packaged, Integrally Geared Centrifugal Air Compressors for Petroleum, Chemical, and Gas Industry Services*; API Std 674, *Positive Displacement Pumps — Reciprocating*; API Std 675, *Positive Displacement Pumps — Controlled Volume*; and API Std 676, *Positive Displacement Pumps — Rotary*.

N **A.7.3.2** Examples of recognized standards include API Std 682, *Pumps — Shaft Sealing Systems for Centrifugal and Rotary Pumps*, and API Std 614, *Lubrication, Shaft-Sealing, and Control-Oil Systems and Auxiliaries for Petroleum, Chemical, and Gas Industry Services*.

N **A.7.3.4** To facilitate safe isolation for maintenance activities, operators should consider isolation methods that are acceptable for the fluid service and operating conditions. Positive isolation, such as double block and bleeds or blinds, should be considered for hazardous fluid equipment connected to higher pressure piping systems.

N **A.7.3.9** An example of a recognized standard is API Std 673, *Special Purpose Centrifugal Fans for General Refinery Services*.

N **A.7.3.10** Examples of recognized standards include API Std 611, *General Purpose Steam Turbines for Petroleum, Chemical, and Gas Industry Services*, and API Std 616, *Gas Turbines for the Petroleum, Chemical and Gas Industry Services*.

N **A.7.3.11** Examples of recognized standards include API Std 611, *General Purpose Steam Turbines for Petroleum, Chemical, and Gas Industry Services*; API Std 541, *Form-Wound Squirrel Cage Induction Motors — 500 Horsepower and Larger*; and API Std 546, *Brushless Synchronous Motors — 500 Horsepower and Larger*.

N **A.7.4.2** Examples of recognized standards include API Std 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*; API Std 625, *Tank Systems for Refrigerated Liquefied Gas Storage*; API Std 650, *Welded Tanks for Oil Storage*; API Spec 12D, *Specification for Field Welded Tanks for Storage of Production Liquids*; API Spec 12F, *Specification for Shop Welded Tanks for Storage of Production Liquids*; and Section VIII, Division 1 or 2, of the ASME *Boiler and Pressure Vessel Code*.

N **A.7.4.3** An example of a recognized standard is API 2000, *Venting Atmospheric and Low-pressure Storage Tanks*.

N **A.7.5.3** Examples of recognized standards are API Std 560, *Fired Heaters for General Refinery Service*, and API Spec 12K, *Specification for Indirect Type Oilfield Heaters*.

N **A.7.5.4** Examples of a recognized standards include NFPA 85 and ASME CSD-1, *Controls and Safety Devices for Automatically Fired Boilers*.

N **A.7.5.5** Cold stretching of completed pressure vessels was first recognized by ASME in Section VIII, Division 1, Mandatory Appendix 44, of the 2013 edition of the *Boiler and Pressure Vessel Code*.

N **A.7.5.6** Examples of recognized standards include API Std 660, *Shell and Tube Heat Exchangers for General Refinery Service*; API Std 661, *Air-Cooled Heat Exchangers for General Refinery Service*; and API Std 662, *Plate Heat Exchangers for General Refinery Services, Part 1 and Part 2*.

Δ **A.7.5.7** Fire protection for electric generating plants and high voltage direct current converter stations should consider recommended practices in NFPA 850, which covers, in part, internal combustion engines or gas turbines exceeding 7500 horsepower per unit.

N **A.7.5.8** Examples of recognized standards include API Std 537, *Flare Details for Petroleum, Petrochemical, and Natural Gas Industries*; API Std 520, *Sizing, Selection, and Installation of Pressure-relieving Devices*; and API Std 521, *Pressure-relieving and Depressuring Systems*.

N **A.8.3.2.2** Ten-thousand (10,000) year wind maps can be found in ICC 500 for tornadoes and hurricanes.

A.8.3.4.1 Foundation designs and container installations should account for applicable site-specific conditions, such as flood loads, wind loads, and seismic loads. The *Canadian Foundation Engineering Manual*, published by the Canadian Geotechnical Society, and Appendix C of API Std 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*, can be used as guides for the subsurface investigation.

N **A.8.3.7.3** For information on corrosion protection, see NACE SP 0169, *Control of External Corrosion on Underground or Submerged Metallic Piping Systems*.

A.8.4.1.1 Figure 11.2 in API Std 625, *Tank Systems for Refrigerated Liquefied Gas Storage*, provides acceptable information and format for a certification document. This form can be used to provide that compliance.

A.8.4.3 Operating requirements for prevention of stratification are located in Section 18.8. Additional details on rollover and rollover prevention can be found in the AGA publication *Introduction to LNG for Personnel Safety*.

Rollover exists when the density of the upper layer increases and/or the density of the lower level decreases such that the more dense upper layer sinks and/or the less dense lower layer rises, causing the two layers to rapidly mix or roll over. This becomes problematic when there also exists a significant temperature difference between the two layers as the rapid mixing will result in a rapid heat transfer and vaporization, which can overwhelm pressure relief valves. This density stratification can occur in a couple of ways.

One mechanism is when the bottom layer experiences relatively higher heat transfer near the base of the tank from the foundation and becomes warmer and less dense compared to the upper layer but cannot evaporate due the hydrostatic head exerted by the top layer.

In this case, the buoyancy force eventually causes the lower warmer and less dense fluid to rise and heat up and vaporize the upper colder layer and any residual superheated product flashes as the hydrostatic head is liberated on its ascent. The relative temperature difference of the layers and subsequent heat transfer can be compounded if filling LNG with different densities than what is stored such that heavier product is bottom filled or lighter product is top filled because the heavier denser product will need more heat to cause the density to lessen to a point where it becomes buoyant enough to rise.

Another mechanism is when the upper layer experiences preferential boil-off of lighter end fluids (i.e., nitrogen) and the liquid in the upper layer becomes warmer and more dense compared to the bottom layer until the density difference becomes large enough that the gravitational force causes the upper warmer layer to sink and heat and vaporize the lower colder fluid.

Both of these phenomena take time to develop and are dependent on a number of factors. Worse heat leak at the bottom of the tank will increase the differential warming and potential for this event. Increased storage time and less cycling will also increase the weathering of the upper layer and warming of the bottom layer and potential for this event. Increased storage volume will also increase the vaporization of the stratified layers and consequence from such an event. Flat bottom storage tanks with less uniform heating and higher head are often specified with level/temperature/density (LTD) gauges, top and bottom fill lines, and inter- and/or intra-tank transfers to monitor and mix the contents of the tank and prevent stratification. Pressure vessels are not typically specified with the same features because pressure vessels have more uniform insulation around the entire tank, shorter cycle times, less head, and smaller volumes that decreases the potential for large density and temperature stratifications to occur and also decreases the vaporization from a rollover.

Δ **A.8.4.6** Appendix Q of API Std 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks,* as well as API Std 625, *Tank Systems for Refrigerated Liquefied Gas Storage,* and ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases,* contain design requirements to allow the tank systems to be purged into or out of service during tank commissioning or decommissioning. Continued outgasing should be considered in the decommissioning procedures.

A.8.4.10.5.3 For double-wall, perlite-insulated tanks, the minimum pressure-relieving capacity can be the governing criterion for pressure relief valve sizing.

A.8.4.10.7.3 It is the responsibility of the user to determine whether the insulation will resist dislodgment by the available fire-fighting equipment and to determine the rate of heat transfer through the insulation when exposed to fire.

A.8.4.11.4(3) It might not be practical to add a cathodic protection system to an existing tank's outer tank bottom because of integral electrical conductivity of the bottom to the tank or LNG facility ground and lightning protection system. Grounding can make a cathodic protection system ineffective.

A.8.4.11.5.4 Moisture accumulation in the conduit can lead to galvanic corrosion or other forms of deterioration within the conduit or heating element.

A.8.4.12.2 API Std 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks,* defines examination as either radiographic or ultrasonic examination.

A.8.4.14.4 OBE ground motion need not exceed the motion represented by a 5 percent damped acceleration response spectrum having a 10 percent probability of exceedance within a 50-year period.

In the United States, the OBE spectra can be developed from the U.S. Geological Survey (USGS) national seismic maps or from site-specific probabilistic seismic hazard analysis. The USGS national seismic maps represent the geometric mean of two horizontal seismic motions in the orthogonal directions rather than the maximum single response. To obtain the maximum response, USGS spectra should be scaled in accordance with Chapter 21.2 of ASCE 7, *Minimum Design Loads and Associated Criteria for Buildings and Other Structures.*

Δ **A.8.4.15.3** Table 1 in EN 14620, *Design and manufacture of site built, vertical, cylindrical, flat-bottomed, steel tanks for the storage of refrigerated, liquefied gases with operating temperatures between 0°C and –165°C,* Part 5, requires the outer concrete tank to be hydrostatically tested prior to installing insulation and the membrane. The membrane is leak tested after all welding is completed. A retest is required following repairs to close leaks. An insulation space monitoring system is required by paragraph 7.2.1.8 of EN 14620, Part 1, which is intended to identify any leaks of LNG gas or vapor into the space between the membrane and the wall.

A.9.1 A pressure-building coil that is integral to an LNG container is not considered to be a vaporizer in the context of NFPA 59A.

Δ **A.9.3.1** Because these vaporizers operate over a temperature range of –260°F to 212°F (–162°C to 100°C), the rules of Section I, Part PVG of the ASME *Boiler and Pressure Vessel Code* are not applicable.

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Δ **A.10.1** Refer to 8.4.2 and Section 17.13 for piping that is part of an LNG tank

A.10.2.1 Piping that is "part of or within the LNG container" is all piping within the storage tank system or container and includes piping attached to the tank or container out to the first flange, piping out to the first connection if threaded, and piping out to the first circumferential weld where there is no flange. Annulus piping is considered to be within the storage tank system.

A.10.2.3 Particular consideration should be given where changes in size of wall thickness occur between pipes, fittings, valves, and components.

A.10.3.1.4 Pipe insulation assemblies tested in an NFPA 274 pipe chase apparatus are considered acceptable if the following are all met during the 10-minute test:

(1) Maximum peak heat release rate of 1.02 mm Btu/hr (300 kW).
(2) Maximum total heat release of 78,700 Btu (83 MJ).
(3) Maximum total smoke release of 5,380 ft^2 (500 m^2).
(4) Any flames generated do not extend 1 ft (0.3 m) or more above the top of the vertical portion of the apparatus at any time.
(5) Temperature of any of the three thermocouples specified does not exceed 1000°F (538°C).

A.10.3.3.3 PFI ES-24, *Pipe Bending Methods, Tolerances, Process and Material Requirements,* can be used as a guide for all pipe bending.

A.10.4.2 Table 5.3.2.3 provides the size of the design spill, which should be considered when specifying the closing time of a powered valve operator.

A.10.4.2.6(1) Valves meeting this requirement would be designed to meet the testing requirements of API Std 607, *Fire Test for Quarter-turn Valves and Valves Equipped with Nonmetallic Seats* , or similar test.

A.10.4.2.10 If excessive stresses are indicated, an increase of the valve closure time or other methods can be used to reduce the stresses to a safe level.

A.10.4.4 Under some conditions, marking materials that contain carbon or heavy metals can corrode aluminum. Marking materials that contain chloride or sulfur compounds can corrode some stainless steels.

N **A.10.5.2.1** Consideration should be given to the need to install piping for the venting/draining to an area having no source of ignition and where no people are present.

N **A.10.6.1** An example of a recognized standard is API RP 2218, *Fireproofing Practices in Petroleum and Petrochemical Processing Plants.*

A.10.7 For information on identification of piping systems, see ASME A13.1, *Scheme for the Identification of Piping Systems.*

A.10.8.3.4 All branch connections shall be attached to the run pipe by full penetration groove welds. See paragraph 328.5.4(d) in ASME B31.3, *Process Piping*.

N **A.10.10.1.1** Examples of recognized standards include API Std 520, *Sizing, Selection, and Installation of Pressure-Relieving Devices in Refineries — Part 1, Sizing and Selection*; API Std 520, *Sizing, Selection, and Installation of Pressure-Relieving Devices in Refineries — Part 2, Installation*; API Std 521, *Pressure-Relieving and Depressuring Systems*; and API Std 527, *Seat Tightness of Safety Relief Valves.*

N **A.10.11** Examples of recognized standards are API Std 520, *Sizing, Selection, and Installation of Pressure-Relieving Devices in Refineries — Part 1, Sizing and Selection*; API Std 520, *Sizing, Selection, and Installation of Pressure-relieving Devices in Refineries — Part 2, Installation*; API Std 521, *Pressure-Relieving and Depressuring Systems;* and API Std 537, *Flare Details for Petroleum, Petrochemical, and Natural Gas Industries.*

Δ **A.10.12.1** 49 CFR 193 includes corrosion protection requirements applicable to the LNG facility.

A.10.13.8 Consideration should be given to the installation of “witness” pieces to monitor the installed condition of material associated with “buried” pipe.

N **A.10.14.1** An example of a recognized standard is ASME B31.8, *Gas Transmission and Distribution Piping Systems.*

N **A.10.14.2** Examples of recognized standards include DNV OS F0101, *Submarine Pipeline Systems — Rules and Standards,* and the *ABS Guide for Building and Classing Subsea Pipeline Systems.*

N **A.11.2** Examples of recognized standards and practices include the following:

(1) API RP 551, *Process Measurement*
(2) API RP 552, *Transmission Systems*
(3) API RP 553, *Refinery Valves and Accessories for Control and Safety Instrumented Systems*
(4) API RP 554, *Process Control Systems, Part 1, 2, and 3*
(5) API RP 556, *Instrumentation, Control, and Protective Systems for Gas Fired Heaters*
(6) ASME CSD-1, *Controls and Safety Devices for Automatically Fired Boilers*
(7) ISA 84.00.01, *Functional Safety: Safety Instrumented Systems for the Process Industry Sector, Parts 1, 2, and 3*
(8) ISA S20, *Specification Forms for Process Measurement and Control Instruments, Primary Elements and Control Valves*
(9) NFPA 85, *Boiler and Combustion Systems Hazards Code*

N **A.11.3.1.3.1** The alarm setting should account for additional flow after the alarm is received and the operator has time to take action to ensure that the tank is not overfilled.

N **A.11.3.2** Flammable process fluids include natural gas liquids and gas condensates.

N **A.11.7.1** The following standards and practices provide guidance for the design, engineering, installation, documentation, and maintenance of basic process control systems, such as distributed control systems and programmable logic controllers, and safety instrumented systems, such as emergency shutdown systems and burner management systems:

(1) API Publ 770, *A Manager’s Guide to Reducing Human Errors*
(2) API RP 754, *Process Safety Performance Indicators for the Refining and Petrochemical Industries*
(3) API RP 755, *Fatigue Management Systems for Personnel in the Refining and Petrochemical Industries*
(4) ISA 5.1, *Instrumentation Symbols and Identification*
(5) ISA 5.2, *Binary Logic Diagrams for Process Operations*
(6) ISA 5.3, *Graphic Symbols for Distributed Control/Shared Display Instrumentation, Logic, and Computer Systems*
(7) ISA 5.4, *Instrument Loop Diagrams*
(8) ISA 5.5, *Graphic Symbols for Process Displays*
(9) ISA 71.01, *Environmental Conditions for Process Measurement and Control Systems: Temperature and Humidity*
(10) ISA 71.04, *Environmental Conditions for Process Measurement and Control Systems: Airborne Contaminants*
(11) ISA 84.00.01, *Functional Safety: Safety Instrumented Systems for the Process Industry Sector, Parts 1, 2, and 3*
(12) ISA 84.00.03, *Mechanical Integrity of Safety Instrumented Systems (SIS)*
(13) ISA 84.00.08, *Guidance for Application of Wireless Sensor Technology to Non-SIS Independent Protection Layers*
(14) ISA 105/IEC 62381, *Automation Systems in the Process Industry — Factory Acceptance Test (FAT), Site Acceptance Test (SAT), and Site Integration Test (SIT)*
(15) ISA RP 60.1, *Control Center Facilities*
(16) ISA RP 60.3, *Human Engineering for Control Centers*
(17) ISA RP 60.4, *Documentation for Control Centers*
(18) ISA RP 60.6, *Nameplates, Labels, and Tags for Control Centers*
(19) ISA S20, *Specification Forms for Process Measurement and Control Instruments, Primary Elements, and Control Valves*
(20) ISA S75.01.01, *Flow Equation for Sizing Control Valves*

N **A.11.7.2** Cybersecurity is an evolving issue that should be included in a security program. The pace of development in cyber threats and security response make it difficult to assign pass/fail criteria. Rather, the intent is to develop a collaborative effort between operators, cybersecurity professionals, and regulators to protect process control systems against identifiable threats. Corporate security policies that have been applied to local facilities can be considered, as appropriate, under this provision. The following identified resources aid in designing protection of the process controls from cyber threats:

(1) ISA 84.00.09, *Security Countermeasures Related to Safety Instrumented Systems*
(2) ISA 99.01.01 (ISA/IEC 62443-1-1), *Security for Industrial Automation and Control Systems, Part 1-1: Terminology, Concepts, and Models*
(3) ISA 99.02.01 (ISA/IEC 62443-2-1), *Security for Industrial Automation and Control Systems, Part 2-1: Establishing an Industrial Automation and Control Systems (IACS) Security Program*

(4) ISA 99.03.03 (ISA/IEC 62443-3-3), *Security for Industrial Automation and Control Systems, Part 3-3: System Security Requirements and Security Levels*
(5) ISA/IEC TR 62443-1-2, *Security for Industrial Automation and Control Systems, Part 1-2: Master Glossary of Terms and Abbreviations*
(6) ISA/IEC TR 62443-1-3, *Security for Industrial Automation and Control Systems, Part 1-3: System Security Compliance Metrics*
(7) ISA/IEC TR 62443-1-4, *Security for Industrial Automation and Control Systems, Part 1-4: Security Life Cycle and Use Cases*
(8) ISA/IEC TR 62443-2-2, *Security for Industrial Automation and Control Systems, Part 2-2: Implementation Guidance for an Industrial Automation and Control Systems (IACS) Security Program*
(9) ISA/IEC TR 62443-2-3, *Security for Industrial Automation and Control Systems, Part 2-3: Patch Management in the IACS Environment*
(10) ISA/IEC TR 62443-2-4, *Security for Industrial Automation and Control Systems, Part 2-4: Requirements for IACS Solution Suppliers*
(11) ISA/IEC TR 62443-3-1, *Security for Industrial Automation and Control Systems, Part 3-1: Security Technologies for IACS*
(12) ISA/IEC TR 62443-3-2, *Security for Industrial Automation and Control Systems, Part 3-2: Security Risk Assessment and System Design*
(13) ISA/IEC TR 62443-4-1, *Security for Industrial Automation and Control Systems, Part 4-1: Product Development Requirements*
(14) ISA/IEC TR 62443-4-2, *Security for Industrial Automation and Control Systems, Part 4-2: Technical Security Requirements for IACS Components*
(15) ISA TR 99.00.01, *Security Technologies for Industrial Automation and Control Systems*

N **A.11.9.1** The AGA publication *Classification of Locations for Electrical Installations in Gas Utility Areas* is a useful reference that provides illustrative examples of the hazardous area installation requirements in Article 500 of*NFPA 70*.

A.11.9.2 NFPA 497; API RP 500, *Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division I and Division 2*; and the AGA document *Classification of Locations for Electrical Installations in Gas Utility Areas*, provide additional guidance material related to hazardous area classification. In the classification of the extent of the hazardous area, consideration should be given to possible variations in the spotting of tank cars and tank vehicles at the loading and unloading points and to the effect those variations might have on the point of connection.

N **A.11.9.3** Methods for determining electrically classified areas and the extent of the classifications are provided in *NFPA 70*, NFPA 497, and API RP 500, *Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division I and Division 2*.

N **A.11.9.6** Examples of other means for preventing the passage of flammable fluids to another portion of the conduit or wiring system can include a physical interruption of the conduit run and of the stranded conductors through the use of an adequately vented junction box containing terminal strip or busbar connections; an exposed section of mineral-insulated (MI) cable using suitable fittings; or an exposed section of single conductors that are incapable of transmitting gases or vapors. See *NFPA 70*, 501.15(e)(2).

A.11.10.1 For information on grounding and bonding, see Section 5.4 and 6.1.3 of NFPA 77, and *NFPA 70*.

A.11.10.3 For information on stray currents, see API RP 2003, *Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents*.

A.11.10.4 For information on lightning protection, see NFPA 780 and API RP 2003, *Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents*.

A.12.1(1) Examples of buildings and structures included in Classification A are tank system foundations, structures supported by the storage tank, structures supporting piping on the storage tank, and structures supporting piping up to the tank isolation valve.

N **A.12.2.1** The term *operating basis earthquake (OBE)* referenced in NFPA 59A is equivalent to the term *operating level earthquake (OLE)* referenced in API Std 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*, and API Std 625, *Tank Systems for Refrigerated Liquefied Gas Storage*. The term *safe shutdown earthquake (SSE)* referenced in NFPA 59A is equivalent to the term *contingency level earthquake (CLE)* referenced in API Std 620 and API Std 625. The term *aftershock level earthquake (ALE)* referenced in NFPA 59A, API Std 625, and API Std 620 is equivalent to the term *safe shutdown aftershock level (SSEaft)* in ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases*.

A.12.9 When considering spacing and construction methods related to occupied permanent and portable buildings at an LNG plant, each proposed building should be analyzed independently. API RP 752, *Management of Hazards Associated with Location of Process Plant Permanent Buildings*, and API RP 753, *Management of Hazards Associated with Location of Process Plant Portable Buildings*, should be referenced.

N **A.13.2.1** The volumetric capacity of impounding areas need not account for ice, snow, or water accumulation. The standard requires provisions for water removal in Section 13.12. The relative density of the snow compared to LNG negates the need to consider its impact on reducing capacity. An LNG tank system foundation or adjacent containers in shared impoundments are examples of something that can substantially impact capacity while smaller pieces of equipment typically are not.

Δ A.13.6 Paragraph 8.2.1.1 requires compliance with API Std 625, *Tank Systems for Refrigerated Liquefied Gas Storage*. Paragraph 5.6 of API Std 625 requires the selection of storage concept to be based on a risk assessment. Annex C of API Std 625 discusses implications of a release of liquid from the primary liquid container and provides specific discussion related to each containment type. Annex D of API Std 625 provides guidance for selection of storage concepts as part of the risk assessment including external and internal events and hazards to be evaluated. Paragraph D.3.2.2 discusses the possibility of sudden failure of the inner tank and advises, "If extra protection from brittle fracture [or unabated ductile crack propagation] is desired, the general practice is to increase" the primary container toughness. Available materials meeting the required specifications of Appendix Q of API Std 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*, and of this standard for LNG service are considered to have crack-arrest properties at LNG service temperature and stress levels.

Therefore, rapid failure of a steel primary container meeting this standard is not considered credible. In membrane containment tank systems, brittle fracture of membrane material is typically not a pertinent hazard for membrane tanks. However, other hazards based on a risk assessment should be considered.

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N **A.15.5.2.2** Examples of recognized standards include DNV OS F0101, *Submarine Pipeline Systems — Rules and Standards*, and the *ABS Guide for Building and Classing Subsea Pipeline Systems*.

A.15.5.3 The ESD required by 15.5.3 can be part of the facility ESD system, or it can be a separate ESD system specific to transfer operations.

Δ **A.16.2** For information on fire protection systems, see NFPA 25, NFPA 68, and NFPA 69.

A.16.2.1 The wide range in size, design, and location of LNG facilities covered by this standard precludes the inclusion of detailed fire protection provisions that apply to all facilities comprehensively. Information for the evaluation can be obtained from numerous sources, including NFPA codes, the U.S. Code of Federal Regulations, building codes applicable to the prospective area, and the equipment manufacturer's information.

N **A.16.2.1.2** A facility is considered as being "significantly altered" if any reconstruction activity that goes beyond mere replacement-in-kind of an existing facility to the extent that capacity is increased making the resulting facility a new LNG facility.

Examples of activity that could be considered a "significant alteration" are the following:

(1) Replacing existing process equipment (pumps, compressors that increase the flow, pressure, temperature beyond that of the processes original design parameters)
(2) Installing additional transfer capabilities
(3) Replacing a liquefaction/regasification processes with one of a larger capacity
(4) Installing additional LNG storage containers

Examples of activity that might not be considered a "significant alteration" are the following:

(1) Replacement of an LNG vaporizer that is a replacement-in-kind and does not increase capacity beyond the original design parameters
(2) Replacement of compression equipment (boiloff, liquefaction, refrigeration) that is a replacement-in-kind and does not increase the original systems design parameters)
(3) Increasing the flow rate of an existing system (transfer, liquefaction, vaporization) but the operational change is within the processes original design parameters (see PHMSA August 21, 2012 written interpretation to Southern LNG Co.)

Refer to the *Federal Register* (45 FR 57402, August 28, 1980) "Liquefied Natural Gas Facilities; Reconsideration of Safety Standards for Siting, Design, and Construction," for additional information.

N **A.16.2.1.4** Installation of temporary fire detection and mitigation should be considered at the locations in the facility that are identified in the evaluation as requiring expansion or replacement of fire protection components. Examples of temporary fire detection and mitigation measures that could be installed during construction of fire protection components include portable gas detectors, portable fire extinguishers, and operator walk downs.

A.16.2.1.5 Where fire protection equipment design, engineering, installation, or testing is not addressed by an NFPA code or standard, other publicly available standards should be considered for use and authorized by the AHJ, if required. Examples of other standards and practices include the following:

(1) API Publ 2510A, *Fire Protection Considerations for the Design and Operation of LPG Storage Facilities*
(2) API RP 2001, *Fire Protection in Refineries*
(3) API RP 2030, *Application of Water Spray Systems for Fire Protection in the Petroleum Industry*
(4) API RP 2218, *Fireproofing Practices in Petroleum and Petrochemical Processing Plants*
(5) ISA 12.13.01, *Performance Requirements for Combustible Gas Detectors*
(6) ISA 84.00.07, *Guidance on the Evaluation of Fire and Gas System Effectiveness*
(7) ISA RP 12.13.02, *Recommended Practice for the Installation, Operation, and Maintenance of Combustible Gas Detection Instruments*
(8) ISA TR 12.13.04, *Performance Requirements for Open Path Combustible Gas Detectors*

A.16.2.2 The evaluation should address all potential fire hazards, including at least the following:

(1) Storage tank relief valves
(2) Impounding areas
(3) LNG trenches and containment pits
(4) Cargo transfer areas
(5) Process, liquefaction, and vaporization areas
(6) Control rooms and control stations

A.16.2.2(5) Areas that may require a fixed pipe/nozzle dry chemical system for fire protection would be areas such as process areas, vaporization areas, transfer areas, and tank vent stacks. Potassium bicarbonate dry chemical agent is recommended due to agent effectiveness on natural gas fires.

A.16.2.2(9) Plant fire brigades are not required by this standard. Where the LNG plant elects to have a fire brigade, NFPA 600 is required for protective equipment and training.

N **A.16.3.1** The wide range in size, design, and location of LNG facilities covered by this standard precludes the inclusion of detailed emergency shutdown system provisions that would apply to all facilities. The scope and configuration of ESD systems and components should be developed during the facility design using recognized hazard assessment methodologies such as those described in ISA 84.00.01, *Functional Safety: Safety Instrumented Systems for the Process Industry Sector*.

N **A.16.3.5** Shutoff valves can be considered protected from fires if they are either located outside a radiant heat zone that would damage the valve or if they are rated fire-safe in accordance with API Spec 6FA, *Fire Test for Valves*; API Spec 6FB, *Fire Test for End Connections*; API Spec 6FD, *Specification for Fire Test for Check Valves*; API RP 2218, *Fireproofing Practices in Petroleum and Petrochemical Processing Plants*; or API Std 607, *Fire Test for Quarter-turn Valves and Valves Equipped with Nonmetallic Seats*.

N **A.16.3.8** API Std 521, *Pressure-relieving and Depressurizing Systems*, provides information on pressure relieving and depressurization systems. The intent of depressurizing a facility, specific system, or both, during an emergency event, particularly one involving a fire, is to reduce the pressure in pressure vessels and affected piping within a reasonable amount of time to minimize the stress on these components which become weaker due to their exposure to the radiant or impinging heat from the fire. If left pressurized at normal design pressures, the higher temperatures from the fire over time (15–30 minutes) can increase the pressure and weaken the materials below their yield point allowing the component to fail/rupture.

N **A.16.3.9** Examples of recognized standards include API RP 580, *Risk-Based Inspection*; AP RP 581, *Risk-Based Inspection Methodology*; and ISA 84.00.01, *Functional Safety: Safety Instrumented Systems for the Process Industry Sector*.

N **A.16.4.2** LNG plants often have mixtures and various hazardous products onsite with different physical and hazardous properties, some of which can change over time. Gas detectors are often placed throughout the site to detect the presence of these flammable or toxic hazards by measuring certain physical properties in the environment in which they are placed (e.g., gas absorption to determine percent LFL or LFL-m). However, these gas detectors are often required to be calibrated with a single gas or gas mixture. As a result, the actual composition of the various flammable and toxic gas mixtures and products will often vary from the composition of a sensor's calibration gas. The owner should verify that the detector will respond accurately to the actual gas mixtures and/or multiple gases for which it is designed to detect. This is best accomplished in consultation with the manufacturer of the gas detector and could include changing the set point or gain of the detector to account for the difference in sensitivities to different gases and/or changing the calibration gas to cover the actual or different gases that could be present.

A.16.4.5 Where installed as determined by the evaluation required in 16.2.1, the following detection system components should be designed, installed, documented, tested, and maintained in accordance with *NFPA 72* or as approved by the AHJ:

(1) Initiating devices (e.g., detectors — smoke, flame, heat, and so on)
(2) Fire system controllers and monitoring panels
(3) Notification appliances (e.g., strobes, sirens, and so on)
(4) Fire system activation devices on installed extinguishment/suppression systems (e.g., water deluge, fixed dry chemical systems, and so on)
(5) Field wiring between initiating, notification components, activation/suppression system, controllers, and monitoring panels
(6) Power supply and backup power equipment for fire alarm system
(7) Any additional devices covered by *NFPA 72* that are determined necessary in the evaluation required by 16.2.1

A.16.6.1 Extinguishers of the dry chemical type usually are preferred. If dry chemical type is utilized, then a potassium bicarbonate dry chemical agent is recommended due to agent effectiveness on natural gas fires. Fixed fire-extinguishing and other fire control systems can be appropriate for the protection of specific hazards as determined in accordance with 16.2.1.

A.16.7.1 Protective clothing for normal liquid transfer operations should include cryogenic gloves, safety glasses, face shields, and coveralls or long-sleeve shirts in accordance with NFPA 2112, NFPA 2113, ASTM F2413, *Standard Specification for Performance Requirements for Protective (Safety) Toe Cap Footwear*, or other approved standard.

Δ **A.16.7.2** The incipient stage is the early stage of a fire, in which the progression has not developed beyond that which can be extinguished using either portable fire extinguishers or handlines flowing up to 125 gpm (473 L/min).

Δ **A.16.7.3** Consideration should be given to containment areas, sumps, and pits that create the potential for confined spaces. Information concerning confined entry practices and procedures can be found in 29 CFR 1910.146; Canadian Federal Employment and Labor Statutes, Part II; and any local, state, or provincial requirements and standards that apply.

A.16.7.4 Natural gas, LNG, and hydrocarbon refrigerants within the process equipment are usually not odorized, and the sense of smell cannot be relied on to detect their presence. Two portable detectors should be available for monitoring when required, with a third detector for backup. This provides a spare detector in the event of failure of one of the primary detectors and also allows verification if the two primary detectors provide different readings.

A.16.8.1.1 The security assessment should include physical and cyber security threats and vulnerabilities.

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N **A.17.3.1** The following factors should be considered in the selection of plant site locations:

(1) Availability of land to accommodate the plant, including provisions for minimum clearances as stated in this standard between components and facilities with respect to each other and the degree that the LNG plant can separate facilities and components to allow for access and maintenance to equipment, reduce congestion, and protect personnel from accidental hazards
(2) Availability of infrastructure to construct and operate the plant, including pipelines; refrigerant, process, and utility makeup supplies; water, sewage, and electric utilities; road, marine, and rail transportation; and telecommunication systems
(3) Availability of personnel and support services to construct, operate, and maintain the plant, including qualified engineering firms and contractors, skilled craftsman, and site support facilities for housing, storage, and laydown
(4) Location of plant with respect to surrounding population, land use, infrastructure, cultural and historical sites, and development and the degree that the LNG plant can separate and protect the public from accidental hazards
(5) Location of plant with respect to emergency response and recovery facilities and the degree that the emergency response and recovery entities are equipped and capable of responding to potential incidents at the plant
(6) Location of plant with respect to security threats and vulnerabilities and the degree that the security forces are capable to deter, protect, and respond to potential security threats and incidents at the plant
(7) Site-specific meteorological and geological data and the degree that the LNG plant can be protected against natural hazards
(8) Site survey information for topography, bathymetry, and subsurface and subsea conditions
(9) Site-specific air, water, noise, luminosity, and other environmental and permitting requirements

(10) Other factors applicable to the specific site that have a bearing on the safety of personnel and the surrounding public, and the reliability, operability, and sustainability of the plant

N **A.17.3.2.2.1.3** Valves meeting this requirement are designed to meet the testing requirements of API 607 or similar test.

A.18.1 Because of many variables, it is not possible to describe in a national standard a set of operating and maintenance procedures that will be adequate from the standpoint of safety in all cases without being burdensome or, in some cases, impractical. For more information on writing operating and maintenance procedures, see AIChE CCPS, *Guidelines for Writing Effective Operating and Maintenance Procedures.*

N **A.18.2.1** The following standards and practices should be considered:

(1) API RP 580, *Risk-Based Inspection*
(2) API RP 581, *Risk-Based Inspection Methodology*
(3) API RP 583, *Corrosion Under Insulation and Fireproofing*
(4) API Std 598, *Valve Inspection and Testing*
(5) API Std 653, *Tank Inspection, Repair, Alteration, and Reconstruction*
(6) ISA 84.00.03, *Mechanical Integrity of Safety Instrumented Systems (SIS)*
(7) NACE SP0198, *Control of Corrosion Under Thermal Insulation and Fireproofing Materials — A Systems Approach*

Procedures should include details for the following, as applicable:

(1) Identify the individuals and necessary qualifications to perform the task.
(2) List preconditions to complete the task, including the equipment and resources needed.
(3) Identify hazards associated with the task.
(4) List applicable forms to be completed as part of the task.
(5) List the steps in sequential order to complete the task and include the following:
    (a) Identify if the task is an independent or dependent action.
    (b) Identify if an approval is required prior to commencing the next step.
    (c) If approval is required, describe the approval steps and communication protocols.
(6) Describe what actions should be taken if a near miss occurs.
(7) Describe what actions should be taken if an abnormal condition occurs.
(8) List the data to be collected and analysis to be performed when an abnormal condition occurs.
(9) Describe the applicable data collection and analysis to be performed.
(10) Describe the process for disseminating the results of the data analysis and corrective actions to the appropriate individuals in the event of an abnormal condition.
(11) Identify the appropriate individuals to receive the data analysis and corrective actions.

Procedures and records should have controls that demonstrate the following:

(1) Personnel are trained to follow the procedures and document the associated task and result of the activity.
(2) Personnel are trained to identify potential near misses.
(3) Personnel are following procedures.
(4) Records are properly completed.
(5) Procedures should describe the timeframe by which the oversight is conducted.
(6) If an abnormal condition occurs while following the procedure, then personnel should be trained to appropriately respond in accordance with operator's procedures. If the unforeseen event and/or hazard were the result of the procedure, then the procedure should be updated immediately and a management of change (MOC) program followed.
(7) If data is collected and analyzed, then the results should be disseminated to the appropriate work groups.

A.18.2.2(7) Safety-related malfunctions can include any of the following:

(1) Fire
(2) Explosion
(3) Estimated property damage of $50,000 or more
(4) Death or personal injury necessitating in-patient hospitalization
(5) A leak or release of hazardous fluid
(6) Unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability, structural integrity, or reliability of an LNG facility that contains, controls, or processes hazardous fluids
(7) Any crack or other material defect that impairs the structural integrity or reliability of an LNG facility that contains, controls, or processes hazardous fluids
(8) Any malfunction or operating error that causes the pressure of a pipeline or facility that contains or processes hazardous fluids to rise above its maximum allowable operating pressure (or working pressure for LNG facilities) plus the build-up allowed for operation of pressure limiting or control devices
(9) Inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of an LNG storage tank
(10) Any safety-related condition that could lead to an imminent hazard and cause (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20-percent reduction in operating pressure or shutdown of operation of a pipeline or a facility that contains or processes hazardous fluids
(11) Safety-related incidents to hazardous material transportations occurring at or enroute to and from the LNG facility
(12) An event that is significant in the judgment of the operator and/or management even though it did not meet the above criteria or the guidelines set forth in an LNG facility's incident management plan

N **A.18.3.11** Management of Change procedure guidance can be found in AIChE CCPS, *Guidelines for the Management of Change for Process Safety.*

A.18.6.1 If an LNG facility is designed to operate unattended, it is recommended that alarm circuits that can transmit an alarm to the nearest attended company facility be provided to indicate abnormal pressure, temperature, or other symptoms of trouble.

N **A.18.6.2.3** The following publications have criteria for settlement of storage containers: ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases*; API Std 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*; and API Std 653, *Tank Inspection, Repair, Alteration, and Reconstruction.*

A.18.6.5.2 The AGA publication *Purging Principles and Practice* can be used as a guide. NFPA 56, while not mandatory for LNG facilities, contains additional guidance for purging activities.

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A.18.6.5.5.5 Many insulating materials that have had prolonged exposure to natural gas or methane retain appreciable quantities of the gas within their pores or interstitial spaces and can require prolonged purging time or utilization of diffusion-type purging activities. Refer to the AGA publication *Purging Principles and Practice.*

N **A.18.6.5.6.2** When planning purge operations, particularly in facilities with process equipment that heats or compresses flammable gas, the autoignition temperature of the gas/air mixtures that exist during and after purging operations must be considered. While auto ignition temperature data is available at low or atmospheric pressure, less empirical data is available at elevated pressures. Auto ignition temperature decreases with increasing pressure and should be considered in determination of appropriate purging endpoints for these situations.

N **A.18.7.4** Examples of recognized standards include ISA 105/IEC 62381, *Automation Systems in the Process Industry — Factory Acceptance Test (FAT), Site Acceptance Test (SAT), and Site Integration Test (SIT)*, and ISA 105/IEC 62382, *Control Systems in the Process Industry — Electrical and Instrumentation Loop Checks.*

A.18.8.7.4 For information on operation of piers, docks, and wharves, see NFPA 30.

A.18.8.7.4.3 The ship's existing lifesaving appliances (i.e., lifeboats) can fulfill the requirement for emergency egress.

A.18.9.1 NFPA 70B provides recommended maintenance to electrical systems that are not already addressed by this standard.

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N **A.18.10.10.3** Examples of seasonal use include liquefaction or vaporization seasons for peak shaving facilities.

A.18.10.10.4(3) Normally, dry chemical–type fire extinguishers are recommended for gas fires.

Δ **A.18.10.10.9** The operation of stop valves beneath pressure relief valves should be managed to minimize the risk of a stop valve not returning to the appropriate position after valves are cycled for relief valve maintenance or any other purposes. See Section VIII, Division I, UG-135, and the nonmandatory Appendix M-5 of the ASME *Boiler Pressure Vessel Code*.

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N **A.18.10.11.1** Regular external inspections can reveal problems with the LNG tank and tank equipment while in service, so that appropriate remedial actions can be taken before these problems escalate to an unacceptable level. Particular attention should be paid to signs of frost build-up or excessive condensation on the external tank surfaces, which could be an indication of the inner or outer container leakage or insulation problems. Deterioration of exposed surfaces due to environmental corrosion could result in through thickness holes and vapor leaks from the tank.

N **A.18.10.11.2** Regular inspection and maintenance of the outer concrete structures exposed to the adverse effects of the environment is an important part of the tank maintenance program ensuring long-lasting continuous operation of the outer containment structures for double, full, or membrane containment tank systems. Any deterioration of the concrete outer containment structure that increases the potential for product liquid or vapor releases should be repaired immediately upon discovery.

N **A.18.10.13.3** NACE SP0169, *Control of External Corrosion on Underground or Submerged Metallic Piping Systems*, and NACE SP0285, *Corrosion Control of Underground Storage Tank Systems by Cathodic Protection*, provide guidance for corrosion control systems for buried and submerged components.

N **A.18.10.13.3.1(2)(a)** Facilities under U.S. federal regulations should comply with 49 CFR 192.461.

N **A.18.10.13.3.1(2)(b)** Facilities under U.S. federal regulations should comply with 49 CFR 192.463.

N **A.18.10.13.6.1(2)** The methods described in Appendix D of 49 CFR Part 192 are also acceptable.

N **A.18.10.13.6.2.2** API RP 583, *Corrosion Under Insulation and Fireproofing*, provides guidance on which corrosion control monitoring program can be established.

N **A.18.10.13.7.1** Corroded pipe can be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

N **A.19.2.1** The QRA should include, but should not be limited to, the methodologies, release scenario selections, assumptions, consequence models and associated validation, hazard levels (i.e., endpoints) for public impact, consequence modeling results, and calculations of event probabilities. Because of the large number of variables in a QRA, it is prudent to have agreement on any such approach early in any project.

Examples of generally accepted QRA protocols include AIChE's *Guidelines for Chemical Process Quantitative Risk Analysis*, and TNO's *Guidelines for Quantitative Risk Assessment, RIVM, The Purple Book.*

A.19.2.2 In this chapter, we use the concept of "risk tolerance" rather than "risk acceptance," adopting the philosophy of the UK Health and Safety Executive (HSE). In discussing the tolerability of risk, the UK HSE has written: "tolerable" does not mean "acceptable." It refers instead to a willingness by society as a whole to live with a risk so as to secure certain benefits in the confidence that the risk is one that is worth taking and that it is being properly controlled. However, it does not imply that everyone would agree reservation to take this risk or have it imposed on them (HSE 2001). Thus, there are various risk tolerance criteria around the world, as shown in Figure 19.10.2(a) and Figure 19.10.2(b). Tolerable individual and societal risk criteria are then subject to the approval of the AHJ.

A.19.3.1 Refer to United Kingdom Health and Safety Executive publication "Reducing Risks, Protecting People" available for free download from www.hse.gov.uk/risk/theory/r2p2.pdf.

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N **A.19.5.1.2** The spectrum of releases should include those identified as design spills in 5.3.2.3. Credible large-release scenarios that could pose risks outside the property line should also be included along with their occurrence probabilities.

Δ **A.19.6.1** Additional references for failure rate data of equipment items are the following:

(1) CCPS Process Equipment Reliability Database. The database is open only to CCPS members, but some data are available in the book, *Guidelines for Process Equipment Reliability Data,* CCPS, 1989.
(2) *Failure Mode / Mechanism Distribution,* Reliability Analysis Center, Rome, NY, 1997.
(3) Johnson, E. M. and J. R. Welker, "Development of an Improved LNG Plant Failure Rate Data Base," GRI-80/0093, Gas Research Institute, Chicago, IL, 1980.
(4) *Nonelectronic Parts Reliability Data,* Reliability Analysis Center, Rome, NY, 1995.
(5) *OREDA, Offshore Reliability Data Handbook,* 4th Edition, SINTEF, 2002. Contains data for use in reliability, availability, and maintainability studies; failure rates; failure mode distribution; and repair times for equipment.
(6) *Reliability Data for Control and Safety Systems,,* SINTEF Industrial Management, Trondheim, Norway, 1998.
(7) *Guidelines for Quantitative Risk Assessment — Purple Book,* CPR 18E, National Institute of Public Health and the Environment, The Netherlands, 2005.
(8) *Failure Rate and Event Data for Use within Risk Assessment,* UK Health and Safety Executive, 2012.
(9) "Storage Incident Frequencies," Report 434-3, International Association of Oil and Gas Producers (OGP), 2010.
(10) "Handbook Failure Frequencies," Flemish Government, LNE Department, The Netherlands, 2009.

One reference for leak frequency data is the Hydrocarbon Releases (HCR) System database from the United Kingdom Health and Safety Executive (HSE) (https://www.hse.gov.uk/hcr3), as well as the following associated documents:

(1) *Guidelines for Quantitative Risk Assessment — Purple Book,* CPR 18E, National Institute of Public Health and the Environment, The Netherlands, 2005.
(2) Lees, F. P., *Loss Prevention in the Process Industry,* 2nd edition, BBS Publishing, 1996.
(3) "Offshore Hydrocarbon Releases Statistics and Analysis, 2002," Hazardous Installations Directorate (HID) statistics report, HSR 2002 002, UK Health and Safety Executive, February 2003.
(4) Quantitative Risk Assessment Data Directory, E&P Forum Report No. 11.8/250, October 1996.
(5) "Revised Guidance on Reporting of Offshore Hydrocarbon Releases," OTO 96 956, UK Health and Safety Executive, November 1996.
(6) "Supplementary Guidance for Reporting Hydrocarbon Releases," UK Offshore Operators Association, September 2002.

N **A.19.6.2** Conditional probabilities include one of many possible probabilities that can be included in risk calculations, including, but not limited to, the following:

(1) Probability of release direction
(2) Probability of environmental conditions
(3) Probability of ignition relative to time and vapor cloud dispersion
(4) Probability and availability for failures on demand of safety equipment (SIS, PRV, FGS, and so on)
(5) Probability of presence of people
(6) Probability of human actions/errors

There are a number of methods in calculating each conditional probability and each can have an influence on each other with unequal distributions or enable certain conditions to exist that would not otherwise be of concern. For example, incident history indicates many of the largest incidents occur during night due to an increase in probability for certain human errors as a result of fatigue, lower staffing/supervisory personnel, and potential for less visibility. This could suggest an increase in probability for releases occurring at night when environmental conditions are less favorable and result in an unequal distribution that affect QRA results. The American Institute of Chemical Engineers, Center for Chemical Process Safety has publications that might be useful, including *Guidelines for Enabling Conditions and Conditional Modifiers in Layers of Protection Analysis* and *Guidelines for Determining the Probability of Ignition of a Released Flammable Mass.*

N **A.19.7.1** The weather data should be based on hourly measurements or statistical equivalent, at a minimum.

N **A.19.7.1.1** Atmospheric stability should be derived from wind speed and other supportive data.

N **A.19.7.3** The topographic and structural features include, but are not limited to, dike profile, aerodynamic roughness of the site, and surrounding area for dispersion behavior of vapors.

N **A.19.7.5** The assessment should include conditional probabilities for the occurrence of conditions which might affect the ignition sources, and for the intervention of active mitigation measures.

Ignition source probabilities might include the probability that equipment might not operate continuously, such as pumps, compressors, and fired equipment. Areas where ignition sources might be present intermittently, such as roadways or transfer operations, can be modified probabilistically. Other conditions, such as day/night variances, can also be incorporated probabilistically into the analysis. If active mitigation measures are incorporated into the analysis, they should be provided with a probability of not working successfully (and thus allowing ignition).

N **A.19.8.2** Plant operating conditions include operation before an accidental release is detected (e.g., normal/abnormal operations, startup/shutdown, day/night shift, number of personnel, manned/unmanned, and so on) and post-detection operation (e.g., partial or complete emergency shutdown, depressurization, elimination of ignition sources, shelter-in-place, evacuation, and so on). In addition, parameters that affect the likelihood of success and duration from operations before an accident transitioning to emergency operating conditions include: number and prioritization of alarms, event escalation time, operator response time and reliability/training, automatic SIS and valve closure times, and ESD/EBD philosophy and causes and effects.

N **A.19.8.3** Overpressures from vapor cloud explosions often do not need to consider projectile impacts; however, BLEVEs and PVBs should include evaluation of projectiles. See A.19.8.4.1 for additional information on how to model projectile impacts.

Δ **A.19.8.4.1** The calculation of the distance to the LFL should take into consideration the validation results in the model evaluation protocol (MEP).

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N **A.19.8.4.1.1** Note that the typical assumption is that there is no distinction between irreversible harm and fatality for persons within an ignited flammable gas or vapor cloud.

N **A.19.8.4.3.1** Note that the typical assumption is that if a building collapses, there is no distinction between irreversible harm and fatality.

A.19.10.2 The Societal Risk Acceptability Criteria used by various jurisdictions in different parts of the world are indicated in the form of a F vs N diagram in Figure A.19.10.2.

A.19.11.1 When mitigation measures are being chosen, the application of the principles of inherent safety have been proved to be the most effective means of reducing risk to persons outside the boundary of the LNG plant. Inherent safety is the use of mitigations that avoid the hazard rather than attempt to control the hazardous event or process. The following basic principles of inherent safety (Kletz, 1991) are based on a hierarchy starting with intensification and ending with administrative controls and procedures:

(1) *Intensification.* Small inventories of hazardous substances reduces the consequences of hazardous events associated with those substances.
(2) *Substitution.* Using safer material in place of a hazardous one will decrease the need for added protective equipment.
(3) *Attenuation.* Carry out hazardous reactions or processes in less hazardous conditions.
(4) *Limitation of effects.* The effects of failures should be reduced through the reduction of inventory sizes and process conditions. This should be accomplished through equipment design rather than by adding protective equipment.
(5) *Simplification.* Complexities provide the potential for error; simplification of LNG facility design reduces the potential for failure.
(6) *Change early.* Identification of hazards and hazardous scenarios early in the design process minimizes the need for changes after the design is complete and minimizes the potential for sometimes complicated integration of changes late in the design cycle.
(7) *Avoid knock-on effects.* Care should be taken to ensure that, as far as reasonably practical, failure should not initiate additional hazardous scenarios and subsequent escalation of effects.
(8) *Making status clear.* Equipment in the facility should be located so that observation of the equipment is easy and convenient; additionally, the design of equipment should allow for the status of the equipment to be easily observed (e.g., valves open or closed, pump running or secured).
(9) *Making incorrect assembly impossible.* As far as possible, components should be selected so that improper installation or construction cannot occur.
(10) *Tolerance.* The design of the process should be such that it will tolerate some amount of improper operation, installation, or process upset.
(11) *Ease of control.* The use of added-on protective equipment to manage risks should be avoided.
(12) *Administrative controls/procedures.* Human error is one of the most common initiators of hazardous events; accordingly, the use of procedural controls to manage risk should be the last option and only when other options are not possible.

With regard to the reduction of risk to persons outside the boundaries of the LNG plant, the basic principles listed above can be simplified into the three-tier hierarchy as follows:

(1) *Tier 1: Remove the hazard.* This first tier of mitigation should focus on providing additional separation distance between the LNG- or gas-containing portions of the LNG facility. Revision of the LNG plant layout and orientation should be considered to increase the separation distance. When changes to the LNG plant layout are being considered, the potential effect of prevailing winds and topography should be evaluated. Care should be given to avoiding the potential for dense clouds to form in valleys and troughs — such clouds will remain in place for

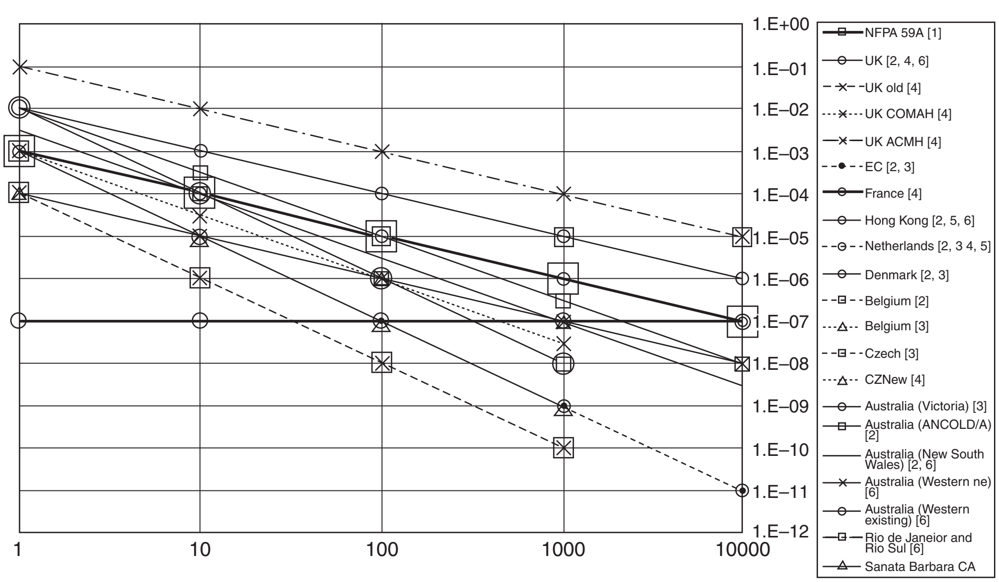

FIGURE A.19.10.2 Societal Risk Tolerance Criteria Used by Different Jurisdictions.

longer periods of time, thereby increasing the risk of ignition.

(2) *Tier 2: Reduce the amount of hazardous substance/prevent the release.* Consideration also should be given to reducing the amount of LNG or gas that can be released during an event. The effect of reducing inventory sizes is that the size of the liquid pool or the length and duration of the jet plume will be reduced and the effects of the ignited pool/ignited jet will be reduced. In this regard, the use of multiple process trains and smaller tanks is an effective way to reduce the impact on the general public from the LNG plant.

(3) *Tier 3: Additional procedures or controls to mitigate the risk.* Where it is not possible to remove the hazard or to prevent or reduce the hazardous effects of a release, additional procedures or controls can be used to mitigate the risk. Human error and failure of control devices are the initiators of the majority of hazardous scenarios; accordingly, these elements should be the last choice when selecting mitigation measures to reduce risk.

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Annex B Seismic Design of LNG Plants

This annex is not a part of the requirements of this NFPA document but is included for informational purposes only.

B.1 Introduction. The purpose of Annex B is to provide information on the selection and use of operating basis earthquake (OBE), safe shutdown earthquake (SSE), and aftershock level earthquake (ALE) seismic levels. These three seismic levels form part of the requirements of this standard for the design of LNG containers, system components required to isolate the container and maintain it in a safe shutdown condition, and any structures or systems the failure of which could affect the integrity of the aforementioned.

B.2 Operating Basis Earthquake (OBE). The OBE is a probable earthquake to which a facility can be subjected during its design life. All elements of the facility defined in 8.4.14.6 are designed to withstand this event in accordance with conventional engineering procedures and criteria, and, therefore, the facility is expected to remain in operation.

The OBE is defined as ground motion having a 10 percent probability of exceedance within a 50-year period (mean return interval of 475 years). For design, this motion is typically represented by design response spectra covering the appropriate ranges of natural period and damping ratio. The OBE design response spectrum is not adjusted by an importance factor. Following any event with a magnitude greater than OBE, the facility is expected to be evaluated for permanent damage and repaired as necessary.

B.3 Safe Shutdown Earthquake (SSE).

Δ **B.3.1** The SSE ground motion is the "risk-adjusted maximum considered earthquake (MCE_R) ground motion," per the definition in ASCE 7, *Minimum Design Loads and Associated Criteria for Buildings and Other Structures*. For most locations, except possibly those near active faults, the MCE_R is determined by adjustment from ground motion that has a 2 percent probability of exceedance in a 50-year period to ground motion that achieves targeted risk requirements. The ASCE 7 adjustment establishes a uniform probability of failure criterion (1 percent chance of collapse in 50 years) for structures designed in accordance with the seismic provisions of ASCE 7. In NFPA 59A, the LNG plant is designed to contain the LNG and prevent catastrophic failure of critical facilities under an SSE event. This more onerous performance criterion is achieved through design requirements of API Std 625, *Tank Systems for Refrigerated Liquefied Gas Storage*; Appendix L of API Std 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*; and ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases*, which contain established response reduction factors to prevent collapse at the design level ground motion.

ASCE 7 requires the base design level earthquake to be two-thirds of MCE_R. Setting the importance factor, I, equal to 1.5 (corresponding to structures containing extra hazardous materials) results in a design level equal to MCE_R. Thus, SSE = MCE_R, as required by this standard, is consistent with ASCE 7 provisions for the design level ground motion. Design of critical facilities to this standard exceeds the design performance requirements of ASCE 7. The LNG facility is not required to remain operational following the SSE event.

B.3.2 The objective of the selection and use of the SSE is to provide a minimum level of public safety in the event of a very low probability seismic event. It is recognized that the required probability level to achieve acceptable public safety varies from project to project, depending on such factors as location and population density. It is desirable to allow the owner flexibility in achieving the required level of public safety.

B.3.3 The SSE level of seismic loading is to be used for a limit state check on the specified components. The specified SSE is the minimum level of ground motion that must be used for the analysis. The actual level must be specified by the owner, and when used in conjunction with other considerations, such as location, siting, type of impounding system, hazard control, local climatic conditions, and physical features, it must be sufficient to ensure adequate public safety to the satisfaction of the regulatory authorities. A risk analysis study is recommended. At the SSE level of seismic loading, primary components of the LNG container are permitted to reach the stress limits specified in API Std 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*, and ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases*. An LNG container subjected to this level of loading must be capable of continuing to contain a full volume of LNG.

B.3.4 The impounding system must, as a minimum, be designed to withstand the SSE level of loading while empty (and while full if a membrane containment tank system) and the ALE level of loading while holding the volume, *V*, as specified in 8.4.14.7. The rationale is that should the LNG container fail following an SSE, the impounding system must remain intact and be able to contain the contents of the LNG container when subjected to an aftershock.

B.3.5 Systems or components, the failure of which could affect the integrity of the LNG container, the impounding system, or the system components required to isolate the LNG container and maintain it in a safe shutdown condition, must be designed to withstand an SSE.

B.3.6 The operator is required to install instrumentation capable of measuring ground motion at the plant site. Following an earthquake that produces ground motion equal to or greater than the design OBE ground motion, it is advisable that the operator of the facility either take the LNG container out of service and have it inspected or prove that the LNG container components have not been subjected to loading in excess of the container's OBE stress level and design criteria. For instance, if the LNG container was partially full during the seismic event, calculations can prove that the container OBE stress levels were not exceeded.

B.4 Aftershock Level Earthquake. The ALE ground motion is defined as 50 percent of the SSE ground motion.

B.5 Design Response Spectra. Using the OBE and SSE ground motions as defined in Section B.2 and B.3.1, respectively, vertical and horizontal design response spectra must be constructed that cover the entire range of anticipated damping ratios and natural periods of vibration, including the fundamental period and damping ratio for the sloshing (convective) mode of vibration of the contained LNG.

B.6 Other Seismic Loads.

B.6.1 Small LNG plants consisting of shop-built LNG containers and limiting processing equipment should be designed for seismic loading using the ground motion specified by ASCE 7, *Minimum Design Loads and Associated Criteria for Buildings and Other Structures*. Either a structural response analysis should be performed or an amplification factor of 0.60 should be applied to the maximum design spectral acceleration (S_{DS}), as defined in 8.5.2.1, to determine the loads on the vessels or piping.

B.6.2 All other structures, buildings, and process equipment must be designed for the seismic loading as determined by the classification and risk category in accordance with Sections 12.1 and 12.2 and ASCE 7, *Minimum Design Loads and Associated Criteria for Buildings and Other Structures*.

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Annex C Informational References

C.1 Referenced Publications. The documents or portions thereof listed in this annex are referenced within the informational sections of this standard and are not part of the requirements of this document unless also listed in Chapter 2 for other reasons.

Δ **C.1.1 NFPA Publications.** National Fire Protection Association, 1 Batterymarch Park, Quincy, MA 02169-7471.

NFPA 25, *Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems*, 2017 edition.

NFPA 30, *Flammable and Combustible Liquids Code*, 2018 edition.

NFPA 52, *Vehicular Natural Gas Fuel Systems Code*, 2019 edition.

NFPA 56, *Standard for Fire and Explosion Prevention During Cleaning and Purging of Flammable Gas Piping Systems*, 2017 edition.

NFPA 68, *Standard on Explosion Protection by Deflagration Venting*, 2018 edition.

NFPA 69, *Standard on Explosion Prevention Systems*, 2019 edition.

NFPA 70®, *National Electrical Code®*, 2017 edition.

NFPA 70B, *Recommended Practice for Electrical Equipment Maintenance*, 2019 edition.

NFPA 72®, *National Fire Alarm and Signaling Code*, 2019 edition.

NFPA 77, *Recommended Practice on Static Electricity*, 2019 edition.

NFPA 85, *Boiler and Combustion Systems Hazards Code*, 2019 edition

NFPA 274, *Standard Test Method to Evaluate Fire Performance Characteristics of Pipe Insulation*, 2018 edition.

NFPA 497, *Recommended Practice for the Classification of Flammable Liquids, Gases, or Vapors and of Hazardous (Classified) Locations for Electrical Installations in Chemical Process Areas*, 2017 edition

NFPA 600, *Standard on Facility Fire Brigades*, 2015 edition.

NFPA 780, *Standard for the Installation of Lightning Protection Systems*, 2017 edition.

NFPA 850, *Recommended Practice for Fire Protection for Electric Generating Plants and High Voltage Direct Current Converter Stations*, 2015 edition.

NFPA 2112, *Standard on Flame-Resistant Clothing for Protection of Industrial Personnel Against Short-Duration Thermal Exposures from Fire*, 2018 edition.

NFPA 2113, *Standard on Selection, Care, Use, and Maintenance of Flame-Resistant Garments for Protection of Industrial Personnel Against Short-Duration Thermal Exposures from Fire*, 2015 edition.

"Evaluating Vapor Dispersion Models for Safety Analysis of LNG Facilities," Fire Protection Research Foundation.

C.1.2 Other Publications.

C.1.2.1 ACI Publications. American Concrete Institute, 38800 Country Club Drive, Farmington Hills, MI 48331.

ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases*, 2011.

N **C.1.2.2 AIChE Publications.** American Institute of Chemical Engineers, 120 Wall Street, FL 23, New York, NY 10005-4020.

Guidelines for Chemical Process Quantitative Risk Analysis, 2000.

Guidelines for Determining the Probability of Ignition of a Released Flammable Mass, 2014.

Guidelines for Enabling Conditions and Conditional Modifiers in Layers of Protection Analysis, 2013.

Guidelines for the Management of Change for Process Safety, March 2008.

Guidelines for Writing Effective Operating and Maintenance Procedures, 1996.

C.1.2.3 AGA Publications. American Gas Association, 400 North Capitol Street, NW, Washington, DC 20001.

AGA XK0101, *Purging Principles and Practice*, 2001.

AGA XL 1001, *Classification of Locations for Electrical Installations in Gas Utility Areas*, 2010, with errata 1 and 2, 2011.

AGA XO8614, *Introduction to LNG for Personnel Safety*, 1986.

Δ **C.1.2.4 API Publications.** American Petroleum Institute, 1220 L Street, NW, Washington, DC 20005-4070.

API Publ 770, *A Manager's Guide to Reducing Human Errors*, 1st edition, 2001.

API Publ 2510A, *Fire Protection Considerations for the Design and Operation of LPG Storage Facilities*, 2nd edition, 1996, revised 2015.

API RP 500, *Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division I and Division 2*, 3rd edition, 2008, revised 2011.

API RP 551, *Process Measurement*, 2nd edition, 2016.

API RP 552, *Transmission Systems*, 1st edition, 1994.

API RP 553, *Refinery Valves and Accessories for Control and Safety Instrumented Systems*, 2nd edition, 2012.

API RP 554, *Process Control Systems, Part 1, 2, and 3*, 2nd edition, 2007, revised 2016.

API RP 556, *Instrumentation, Control, and Protective Systems for Gas Fired Heaters*, 2nd edition, 2011.

API RP 580, *Risk-Based Inspection*, 3rd edition, 2016.

API RP 581, *Risk-Based Inspection Methodology*, 3rd edition, 2016.

API RP 583, *Corrosion Under Insulation and Fireproofing*, 1st edition, 2014.

API RP 752, *Management of Hazards Associated with Location of Process Plant Permanent Buildings,* 2009.

API RP 753, *Management of Hazards Associated with Location of Process Plant Portable Buildings,* 2007 , reaffirmed 2012.

API RP 754, *Process Safety Performance Indicators for the Refining and Petrochemical Industries*, 2nd edition, 2016, errata 1 2017.

API RP 755, *Fatigue Management Systems for Personnel in the Refining and Petrochemical Industries*, 1st edition, 2010.

API RP 2001, *Fire Protection in Refineries*, 9th edition, 2012.

API RP 2003, *Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents,* 2015.

API RP 2030, *Application of Water Spray Systems for Fire Protection in the Petrochemical Industry*, 4th edition, 2014.

API RP 2218, *Fireproofing Practices in Petroleum and Petrochemical Processing Plants*, 3rd edition, 2013.

API Spec 6FA, *Fire Test for Valves*, 1999, reaffirmed 2011.

API Spec 6FB, *Fire Test for End Connections*, 3rd edition, revised 2011.

API Spec 6FD, *Specification for Fire Test for Check Valves*, 1st edition, revised 2013.

API Spec 12D, *Specification for Field Welded Tanks for Storage of Production Liquids*, 12th edition, 2017.

API Spec 12F, *Specification for Shop Welded Tanks for Storage of Production Liquids*, 12 edition, 2008.

API Spec 12K, *Specification for Indirect Type Oilfield Heaters*, 2008.

API Std 520, *Sizing, Selection, and Installation of Pressure-Relieving Devices in Refineries — Part 1, Sizing and Selection*, 9th edition, 2014.

API Std 520, *Sizing, Selection, and Installation of Pressure-Relieving Devices in Refineries — Part 2, Installation*, 6th edition, 2015.

API Std 521, *Pressure-relieving and Depressuring Systems*, 6th edition, 2014.

API Std 527, *Seat Tightness of Safety Relief Valves*, 4th edition, 2014.

API Std 537, *Flare Details for Petroleum, Petrochemical, and Natural Gas Industries*, 3rd edition, 2017.

API Std 541, *Form-Wound Squirrel Cage Induction Motors — 500 Horsepower and Larger*, 5th edition, 2014.

API Std 546, *Brushless Synchronous Motors — 500 Horsepower and Larger*, 3rd edition, 2008.

API Std 560, *Fired Heaters for General Refinery Service*, 5th edition, 2016.

API Std 598, *Valve Inspection and Testing*, 10th edition, 2016.

API Std 607, *Fire Test for Quarter-turn Valves and Valves Equipped with Nonmetallic Seats*, 2016.

API Std 610, *Centrifugal Pumps for Petroleum, Petrochemical and Natural Gas Industries*, 11th edition, 2010, with errata 2011.

API Std 611, *General Purpose Steam Turbines for Petroleum, Chemical, and Gas Industry Services*, 5th edition, 2008.

API Std 614, *Lubrication, Shaft-Sealing, and Control-Oil Systems and Auxiliaries for Petroleum, Chemical, and Gas Industry Services*, 5th edition, 2008, with errata 2008.

API Std 616, *Gas Turbines for the Petroleum, Chemical and Gas Industry Services*, 5th edition, 2011.

API Std 617, *Axial and Centrifugal Compressors and Expander-compressors*, 2016.

API Std 618, *Reciprocating Compressors for Petroleum, Chemical, and Gas Industry Services*, 2007, errata 1, 2009, errata 2, 2010.

API Std 619, *Rotary-Type Positive-Displacement Compressors for Petroleum, Petrochemical, and Natural Gas Industry Services*, 2010.

API Std 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*, 2013 addendum 1, 2014.

API Std 625, *Tank Systems for Refrigerated Liquefied Gas Storage*, 2010, Addendum 1, 2013, addendum 2, 2014.

API Std 650, *Welded Tanks for Oil Storage*, 12th edition, 2003, errata 1 2013, errata 2 2014, addendum 1 2014, addendum 2 2016.

API Std 653, *Tank Inspection, Repair, Alteration, and Reconstruction*, 5th edition, 2014.

API Std 660, *Shell and Tube Heat Exchangers for General Refinery Service*, 9th edition, 2015.

API Std 661, *Air-Cooled Heat Exchangers for General Refinery Service*, 7th edition, 2013.

API Std 662, *Plate Heat Exchangers for General Refinery Services, Part 1 and Part 2,* 1st edition, 2006, revised 2011.

API Std 672, *Packaged, Integrally Geared Centrifugal Air Compressors for Petroleum, Chemical, and Gas Industry Services*, 4th edition, 2004, errata 1 2007, errata 2 2010.

API Std 673, *Special Purpose Centrifugal Fans for General Refinery Services*, 3rd edition, 2014.

API Std 674, *Positive Displacement Pumps — Reciprocating*, 3rd edition, 2010, revised 2016, errata 1 2014, errata 2 2015.

API Std 675, *Positive Displacement Pumps — Controlled Volume*, 3rd edition, 2012, errata 2014.

API Std 676, *Positive Displacement Pumps — Rotary*, 3rd edition, 2009, revised 2015.

API Std 682, *Pumps — Shaft Sealing Systems for Centrifugal and Rotary Pumps*, 4th edition, 2014.

API Std 2000, *Venting Atmospheric and Low-pressure Storage Tanks*, 7th edition, 2014.

C.1.2.5 ASCE Publications. American Society of Civil Engineers, 1801 Alexander Bell Drive, Reston, VA 20191-4400.

ASCE 7, *Minimum Design Loads and Associated Criteria for Buildings and Other Structures*, 2016.

C.1.2.6 ASME Publications. ASME International, Two Park Avenue, New York, NY 10016-5990.

ASME *Boiler and Pressure Vessel Code*, 2017.

ASME A13.1, *Scheme for the Identification of Piping Systems*, 2015.

ASME B31.3, *Process Piping*, 2016.

ASME B31.8, *Gas Transmission and Distribution Piping Systems*, 2016.

ASME CSD-1, *Controls and Safety Devices for Automatically Fired Boilers*, 2015.

N **C.1.2.7 ASTM International Publications.** ASTM International, 100 Barr Harbor Drive, P.O. Box C700, West Conshohocken, PA, 19428-2959.

ASTM A36, *Standard Specification for Carbon Structural Steel*, 2014.

ASTM A53, *Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless*, 2012.

ASTM A106, *Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service*, 2018.

ASTM F2413, *Standard Specification for Performance Requirements for Protective (Safety) Toe Cap Footwear*, 2017.

N **C.1.2.8 BSI Publications.** British Standards Institution, 389 Chiswick High Road, London, W4 4AL, UK.

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Index

Sequence of Events for the Standards Development Process

Once the current edition is published, a Standard is opened for Public Input.

Step 1 – Input Stage

- Input accepted from the public or other committees for consideration to develop the First Draft
- Technical Committee holds First Draft Meeting to revise Standard (23 weeks); Technical Committee(s) with Correlating Committee (10 weeks)
- Technical Committee ballots on First Draft (12 weeks); Technical Committee(s) with Correlating Committee (11 weeks)
- Correlating Committee First Draft Meeting (9 weeks)
- Correlating Committee ballots on First Draft (5 weeks)
- First Draft Report posted on the document information page

Step 2 – Comment Stage

- Public Comments accepted on First Draft (10 weeks) following posting of First Draft Report
- If Standard does not receive Public Comments and the Technical Committee chooses not to hold a Second Draft meeting, the Standard becomes a Consent Standard and is sent directly to the Standards Council for issuance (see Step 4) or
- Technical Committee holds Second Draft Meeting (21 weeks); Technical Committee(s) with Correlating Committee (7 weeks)
- Technical Committee ballots on Second Draft (11 weeks); Technical Committee(s) with Correlating Committee (10 weeks)
- Correlating Committee Second Draft Meeting (9 weeks)
- Correlating Committee ballots on Second Draft (8 weeks)
- Second Draft Report posted on the document information page

Step 3 – NFPA Technical Meeting

- Notice of Intent to Make a Motion (NITMAM) accepted (5 weeks) following the posting of Second Draft Report
- NITMAMs are reviewed and valid motions are certified by the Motions Committee for presentation at the NFPA Technical Meeting
- NFPA membership meets each June at the NFPA Technical Meeting to act on Standards with "Certified Amending Motions" (certified NITMAMs)
- Committee(s) vote on any successful amendments to the Technical Committee Reports made by the NFPA membership at the NFPA Technical Meeting

Step 4 – Council Appeals and Issuance of Standard

- Notification of intent to file an appeal to the Standards Council on Technical Meeting action must be filed within 20 days of the NFPA Technical Meeting
- Standards Council decides, based on all evidence, whether to issue the standard or to take other action

Notes:

1. Time periods are approximate; refer to published schedules for actual dates.
2. Annual revision cycle documents with certified amending motions take approximately 101 weeks to complete.
3. Fall revision cycle documents receiving certified amending motions take approximately 141 weeks to complete.

Committee Membership Classifications[1,2,3,4]

The following classifications apply to Committee members and represent their principal interest in the activity of the Committee.

1. M *Manufacturer:* A representative of a maker or marketer of a product, assembly, or system, or portion thereof, that is affected by the standard.
2. U *User:* A representative of an entity that is subject to the provisions of the standard or that voluntarily uses the standard.
3. IM *Installer/Maintainer:* A representative of an entity that is in the business of installing or maintaining a product, assembly, or system affected by the standard.
4. L *Labor:* A labor representative or employee concerned with safety in the workplace.
5. RT *Applied Research/Testing Laboratory:* A representative of an independent testing laboratory or independent applied research organization that promulgates and/or enforces standards.
6. E *Enforcing Authority:* A representative of an agency or an organization that promulgates and/or enforces standards.
7. I *Insurance:* A representative of an insurance company, broker, agent, bureau, or inspection agency.
8. C *Consumer:* A person who is or represents the ultimate purchaser of a product, system, or service affected by the standard, but who is not included in (2).
9. SE *Special Expert:* A person not representing (1) through (8) and who has special expertise in the scope of the standard or portion thereof.

NOTE 1: "Standard" connotes code, standard, recommended practice, or guide.

NOTE 2: A representative includes an employee.

NOTE 3: While these classifications will be used by the Standards Council to achieve a balance for Technical Committees, the Standards Council may determine that new classifications of member or unique interests need representation in order to foster the best possible Committee deliberations on any project. In this connection, the Standards Council may make such appointments as it deems appropriate in the public interest, such as the classification of "Utilities" in the National Electrical Code Committee.

NOTE 4: Representatives of subsidiaries of any group are generally considered to have the same classification as the parent organization.

Submitting Public Input / Public Comment Through the Online Submission System

Soon after the current edition is published, a Standard is open for Public Input.

Before accessing the Online Submission System, you must first sign in at www.nfpa.org. *Note: You will be asked to sign-in or create a free online account with NFPA before using this system:*

a. Click on Sign In at the upper right side of the page.
b. Under the Codes and Standards heading, click on the "List of NFPA Codes & Standards," and then select your document from the list or use one of the search features.

OR

a. Go directly to your specific document information page by typing the convenient shortcut link of www.nfpa.org/document# (Example: NFPA 921 would be www.nfpa.org/921). Sign in at the upper right side of the page.

To begin your Public Input, select the link "The next edition of this standard is now open for Public Input" located on the About tab, Current & Prior Editions tab, and the Next Edition tab. Alternatively, the Next Edition tab includes a link to Submit Public Input online.

At this point, the NFPA Standards Development Site will open showing details for the document you have selected. This "Document Home" page site includes an explanatory introduction, information on the current document phase and closing date, a left-hand navigation panel that includes useful links, a document Table of Contents, and icons at the top you can click for Help when using the site. The Help icons and navigation panel will be visible except when you are actually in the process of creating a Public Input.

Once the First Draft Report becomes available there is a Public Comment period during which anyone may submit a Public Comment on the First Draft. Any objections or further related changes to the content of the First Draft must be submitted at the Comment stage.

To submit a Public Comment you may access the online submission system utilizing the same steps as previously explained for the submission of Public Input.

For further information on submitting public input and public comments, go to: http://www.nfpa.org/publicinput.

Other Resources Available on the Document Information Pages

About tab: View general document and subject-related information.

Current & Prior Editions tab: Research current and previous edition information on a Standard.

Next Edition tab: Follow the committee's progress in the processing of a Standard in its next revision cycle.

Technical Committee tab: View current committee member rosters or apply to a committee.

Technical Questions tab: For members and Public Sector Officials/AHJs to submit questions about codes and standards to NFPA staff. Our Technical Questions Service provides a convenient way to receive timely and consistent technical assistance when you need to know more about NFPA codes and standards relevant to your work. Responses are provided by NFPA staff on an informal basis.

Products & Training tab: List of NFPA's publications and training available for purchase.

Information on the NFPA Standards Development Process

I. Applicable Regulations. The primary rules governing the processing of NFPA standards (codes, standards, recommended practices, and guides) are the NFPA *Regulations Governing the Development of NFPA Standards (Regs)*. Other applicable rules include NFPA *Bylaws*, NFPA *Technical Meeting Convention Rules*, NFPA *Guide for the Conduct of Participants in the NFPA Standards Development Process*, and the NFPA *Regulations Governing Petitions to the Board of Directors from Decisions of the Standards Council*. Most of these rules and regulations are contained in the *NFPA Standards Directory*. For copies of the *Directory*, contact Codes and Standards Administration at NFPA Headquarters; all these documents are also available on the NFPA website at "www.nfpa.org."

The following is general information on the NFPA process. All participants, however, should refer to the actual rules and regulations for a full understanding of this process and for the criteria that govern participation.

II. Technical Committee Report. The Technical Committee Report is defined as "the Report of the responsible Committee(s), in accordance with the Regulations, in preparation of a new or revised NFPA Standard." The Technical Committee Report is in two parts and consists of the First Draft Report and the Second Draft Report. (See *Regs* at Section 1.4.)

III. Step 1: First Draft Report. The First Draft Report is defined as "Part one of the Technical Committee Report, which documents the Input Stage." The First Draft Report consists of the First Draft, Public Input, Committee Input, Committee and Correlating Committee Statements, Correlating Notes, and Ballot Statements. (See *Regs* at 4.2.5.2 and Section 4.3.) Any objection to an action in the First Draft Report must be raised through the filing of an appropriate Comment for consideration in the Second Draft Report or the objection will be considered resolved. [See *Regs* at 4.3.1(b).]

IV. Step 2: Second Draft Report. The Second Draft Report is defined as "Part two of the Technical Committee Report, which documents the Comment Stage." The Second Draft Report consists of the Second Draft, Public Comments with corresponding Committee Actions and Committee Statements, Correlating Notes and their respective Committee Statements, Committee Comments, Correlating Revisions, and Ballot Statements. (See *Regs* at 4.2.5.2 and Section 4.4.) The First Draft Report and the Second Draft Report together constitute the Technical Committee Report. Any outstanding objection following the Second Draft Report must be raised through an appropriate Amending Motion at the NFPA Technical Meeting or the objection will be considered resolved. [See *Regs* at 4.4.1(b).]

V. Step 3a: Action at NFPA Technical Meeting. Following the publication of the Second Draft Report, there is a period during which those wishing to make proper Amending Motions on the Technical Committee Reports must signal their intention by submitting a Notice of Intent to Make a Motion (NITMAM). (See *Regs* at 4.5.2.) Standards that receive notice of proper Amending Motions (Certified Amending Motions) will be presented for action at the annual June NFPA Technical Meeting. At the meeting, the NFPA membership can consider and act on these Certified Amending Motions as well as Follow-up Amending Motions, that is, motions that become necessary as a result of a previous successful Amending Motion. (See 4.5.3.2 through 4.5.3.6 and Table 1, Columns 1-3 of *Regs* for a summary of the available Amending Motions and who may make them.) Any outstanding objection following action at an NFPA Technical Meeting (and any further Technical Committee consideration following successful Amending Motions, see *Regs* at 4.5.3.7 through 4.6.5.3) must be raised through an appeal to the Standards Council or it will be considered to be resolved.

VI. Step 3b: Documents Forwarded Directly to the Council. Where no NITMAM is received and certified in accordance with the Technical Meeting Convention Rules, the standard is forwarded directly to the Standards Council for action on issuance. Objections are deemed to be resolved for these documents. (See *Regs* at 4.5.2.5.)

VII. Step 4a: Council Appeals. Anyone can appeal to the Standards Council concerning procedural or substantive matters related to the development, content, or issuance of any document of the NFPA or on matters within the purview of the authority of the Council, as established by the Bylaws and as determined by the Board of Directors. Such appeals must be in written form and filed with the Secretary of the Standards Council (see *Regs* at Section 1.6). Time constraints for filing an appeal must be in accordance with 1.6.2 of the *Regs*. Objections are deemed to be resolved if not pursued at this level.

VIII. Step 4b: Document Issuance. The Standards Council is the issuer of all documents (see Article 8 of *Bylaws*). The Council acts on the issuance of a document presented for action at an NFPA Technical Meeting within 75 days from the date of the recommendation from the NFPA Technical Meeting, unless this period is extended by the Council (see *Regs* at 4.7.2). For documents forwarded directly to the Standards Council, the Council acts on the issuance of the document at its next scheduled meeting, or at such other meeting as the Council may determine (see *Regs* at 4.5.2.5 and 4.7.4).

IX. Petitions to the Board of Directors. The Standards Council has been delegated the responsibility for the administration of the codes and standards development process and the issuance of documents. However, where extraordinary circumstances requiring the intervention of the Board of Directors exist, the Board of Directors may take any action necessary to fulfill its obligations to preserve the integrity of the codes and standards development process and to protect the interests of the NFPA. The rules for petitioning the Board of Directors can be found in the *Regulations Governing Petitions to the Board of Directors from Decisions of the Standards Council* and in Section 1.7 of the *Regs*.

X. For More Information. The program for the NFPA Technical Meeting (as well as the NFPA website as information becomes available) should be consulted for the date on which each report scheduled for consideration at the meeting will be presented. To view the First Draft Report and Second Draft Report as well as information on NFPA rules and for up-to-date information on schedules and deadlines for processing NFPA documents, check the NFPA website (www.nfpa.org/docinfo) or contact NFPA Codes & Standards Administration at (617) 984-7246.