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NFPA® 59A

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

2013 Edition



NFPA, 1 Batterymarch Park, Quincy, MA 02169-7471
An International Codes and Standards Organization

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NFPA® 59A

Standard for the

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

2013 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, and acted on by NFPA at its June Association Technical Meeting held June 11–14, 2012, in Las Vegas, NV. It was issued by the Standards Council on August 9, 2012, with an effective date of August 29, 2012, and supersedes all previous editions.

This edition of NFPA 59A was approved as an American National Standard on August 29, 2012.

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, this 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 its standard 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 this purpose. The 1971 edition was the first edition 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, has been revised and relocated to the mandatory text as new Chapter 15, Performance (Risk Assessment) Based LNG Plant Siting. Use of the performance-based option requires approval of the authority having jurisdiction. The performance-based option requires 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 must also be met. Chapter 15 provides 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 incorporates 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 have been reorganized for easier use.

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Donald Barber, Enmat International (UK), United Kingdom [SE]
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Christopher Bourne, Massachusetts Department of Public Utilities, MA [E]
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Jeffrey K. Brightwell, Trunkline LNG, LA [U]
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Rep. Steel Tank Institute/Steel Plate Fabricators Association
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Kevin L. Ritz, Baltimore Gas & Electric Company, MD [U]
Rep. American Gas Association
Roger J. Roue, SIGTTO, United Kingdom [U]
James H. Stannard, Jr., Stannard & Company, NJ [SE]
Joseph E. Zanoni, Baker Engineering & Risk Consultants, Inc., TX [SE]

Alternates

Jeffrey P. Beale, CH-IV International, MD [SE]
(Alt. to J. H. Stannard, Jr.)
John M. Blanchard, CB&I, IL [M]
(Alt. to B. L. Eisentrout)
Leo Campos, American Bureau of Shipping, TX [E]
(Alt. to J. J. Gaughan)
Allan M. Clarke, Duke Energy Corporation, TX [U]
(Alt. to J. K. Brightwell)
Dale R. Edlbeck, Tyco/Ansul, WI [M]
(Voting Alt. to Tyco Rep.)
Filippo Gavelli, GexCon US, MD [SE]
(Alt. to P. K. Raj)
Stanley T. Kastanas, U.S. Department of Transportation, MA [E]
(Alt. to C. A. Helm)
Davis R. Parsons, BWD Consulting, CA [U]
(Alt. to P. A. Micciche)
Thomas V. Rodante, Baker Engineering & Risk Consultants, Inc., TX [SE]
(Alt. to J. E. Zanoni)
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(Alt. to T. J. Felleisen)

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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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Standard for the

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

Chapter 1 Administration

1.1* Scope.

1.1.1 This standard shall apply to the following:

(1) Facilities that liquefy natural gas
(2) Facilities that store, vaporize, transfer, and handle liquefied natural gas (LNG)
(3) The training of all personnel involved with LNG
(4) The design, location, construction, maintenance, and operation of all LNG facilities

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 location, 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.

1.3.2 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 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.

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

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

1.6.3 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 10, *Standard for Portable Fire Extinguishers,* 2010 edition.

NFPA 11, *Standard for Low-, Medium-, and High-Expansion Foam,* 2010 edition.

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NFPA 12, *Standard on Carbon Dioxide Extinguishing Systems,* 2011 edition.

NFPA 12A, *Standard on Halon 1301 Fire Extinguishing Systems,* 2009 edition.

NFPA 13, *Standard for the Installation of Sprinkler Systems,* 2013 edition.

NFPA 14, *Standard for the Installation of Standpipe and Hose Systems,* 2010 edition.

NFPA 15, *Standard for Water Spray Fixed Systems for Fire Protection,* 2012 edition.

NFPA 16, *Standard for the Installation of Foam-Water Sprinkler and Foam-Water Spray Systems,* 2011 edition.

NFPA 17, *Standard for Dry Chemical Extinguishing Systems,* 2009 edition.

NFPA 20, *Standard for the Installation of Stationary Pumps for Fire Protection,* 2013 edition.

NFPA 22, *Standard for Water Tanks for Private Fire Protection,* 2008 edition.

NFPA 24, *Standard for the Installation of Private Fire Service Mains and Their Appurtenances,* 2013 edition.

NFPA 25, *Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems,* 2011 edition.

NFPA 30, *Flammable and Combustible Liquids Code,* 2012 edition.

NFPA 37, *Standard for the Installation and Use of Stationary Combustion Engines and Gas Turbines,* 2010 edition.

NFPA 54, *National Fuel Gas Code,* 2012 edition.

NFPA 58, *Liquefied Petroleum Gas Code,* 2011 edition.

NFPA 59, *Utility LP-Gas Plant Code,* 2012 edition.

NFPA 70®, National Electrical Code®, 2011 edition.

NFPA 72®, National Fire Alarm and Signaling Code, 2013 edition.

NFPA *101®, Life Safety Code®,* 2012 edition.

NFPA 274, *Standard Test Method to Evaluate Fire Performance Characteristics of Pipe Insulation,* 2009 edition.

NFPA 385, *Standard for Tank Vehicles for Flammable and Combustible Liquids,* 2012 edition.

NFPA 600, *Standard on Industrial Fire Brigades,* 2010 edition.

NFPA 1221, *Standard for the Installation, Maintenance, and Use of Emergency Services Communications Systems,* 2013 edition.

NFPA 1901, *Standard for Automotive Fire Apparatus,* 2009 edition.

NFPA 2001, *Standard on Clean Agent Fire Extinguishing Systems,* 2012 edition.

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ACI 318, *Building Code Requirements for Structural Concrete and Commentary,* 2008.

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,* 2010.

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ASCE 7, *Minimum Design Loads for Buildings and Other Structures,* 2010.

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

ASME *Boiler and Pressure Vessel Code,* 2007.

ASME B 31.3, *Process Piping,* 2008.

ASME B 31.5, *Refrigeration Piping,* 2006.

ASME B 31.8, *Gas Transmission and Distribution Piping Systems,* 2007.

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

ASTM E 84, *Standard Test Method for Surface Burning Characteristics of Building Materials,* 2011.

ASTM E 136, *Standard Test Method for Behavior of Materials in a Vertical Tube Furnace at 750°C,* 2009.

ASTM E 2652, *Standard Test Method for Behavior of Materials in a Tube Furnace with a Cone-shaped Airflow Stabilizer, at 750 Degrees C,* 2009.

2.3.7 CGA Publications. Compressed Gas Association, 14501 George Carter Way, Suite 103, Chantilly, VA 20151-2923.

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

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

2.3.8 CSA Publications. Canadian Standards Association, 5060 Spectrum Way, Mississauga, ON, L4W 5N6, Canada.

CSA B51, *Boiler, Pressure Vessel and Pressure Piping Code,* 2007.

CSA C22.1, *Canadian Electrical Code,* 2006.

2.3.9 IEEE Publications. Institute of Electrical and Electronics Engineers, Three Park Avenue, 17th Floor, New York, NY 10016-5997.

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NACE SP 0169, *Control of External Corrosion of Underground or Submerged Metallic Piping Systems,* 2007.

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NFPA 54, *National Fuel Gas Code,* 2012 edition.
NFPA *101*®, *Life Safety Code*®, 2012 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. A document, the main text of which contains only mandatory provisions using the word "shall" to indicate requirements and which 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 *Manual of Style for NFPA Technical Committee Documents.*

3.3 General Definitions.

3.3.1 Barrel. A unit of volume that is equal to 42 gal (0.159 m^3).

3.3.2 Bunkering. The loading of a ship's bunker or tank with fuel oil 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 Components. A part, or a system of parts, that functions as a unit in an LNG plant 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 single-wall vessel for storing gaseous and/or liquefied natural 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.

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

3.3.5.3 ***Tank System.*** Low pressure (less than 15 psi) equipment designed for the purpose of storing liquefied natural gas consisting of one or more containers, together with various accessories, appurtenances, and insulation.

3.3.5.3.1* ***Double Containment Tank System.*** A single containment tank system surrounded by and within 20 ft (6 m) of a containment wall (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.

3.3.5.3.2* ***Full Containment Tank System.*** A tank system container in which the inner (primary) container is self standing and 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.

3.3.5.3.3 ***Membrane Tank System.*** A tank system consisting of a thin metal primary container together with thermal insulation and a concrete container jointly forming an integrated, composite structure that provides liquid containment, where hydrostatic loads and other loadings on the membrane are transferred via the load-bearing insulation onto the concrete container such that the vapors are contained by the tank roof.

3.3.5.3.4* ***Single Containment Tank System.*** A single wall container or a double wall tank system in which only the self-supporting primary or inner container is designed to contain LNG.

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

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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,** 2010]

3.3.9 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.

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

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

3.3.12 Flame Spread Index. A number obtained according to ASTM E 84, *Standard Test Method for Surface Burning Characteristics of Building Materials*, or ANSI/UL 723, *Standard for Test for Surface Burning Characteristics of Building Materials.*

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

3.3.14 Impounding Area. An area defined through the use of dikes or the site topography for the purpose of containing any accidental spill of LNG or flammable refrigerants.

3.3.15 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.

3.3.16 LNG Plant. A facility whose components can be used to store, condition, liquefy, or vaporize natural gas.

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

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

3.3.19 Noncombustible Material. *See Section 4.6.* [***101,*** 2012].

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

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

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

3.3.23 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.

3.3.24 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,** 2012]

3.3.25 Tank Vehicle. See 3.3.3, Cargo Tank Vehicle.

3.3.26* Transfer Area. The portion of a liquefied natural gas (LNG) plant containing a piping system where LNG, flammable liquids, or flammable refrigerants are introduced into or removed from the plant or where piping connections are connected or disconnected routinely.

3.3.27 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.

3.3.28* 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.

3.3.29 Vaporizer.

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

3.3.29.2 ***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,** 2010]

3.3.29.2.1 ***Integral Heated Vaporizer.*** A vaporizer, including submerged combustion vaporizers, in which the heat source is integral to the actual vaporizing exchanger. [**52,** 2010]

3.3.29.2.2 ***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.

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

3.3.30 Water Capacity The amount of water at 60°F (16°C) required to fill a container. [**52,** 2010]

Chapter 4 General Requirements

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

4.2 Corrosion Control Overview.

4.2.1 Components shall not be constructed, repaired, replaced, or significantly altered until a qualified person reviews the applicable design drawings and materials specifications from a corrosion control viewpoint and determines that the materials involved will not impair the safety or reliability of the component or any associated components.

4.2.2 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 materials specified
(2) A failure caused by corrosion
(3) An inspection that reveals a significant deterioration of the component due to corrosion

4.3 Control Center.

4.3.1 Each LNG plant, other than those complying with Chapter 13, shall have a control center from which operations and warning devices are monitored as required by Section 4.3.

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

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(1) It shall be located apart from or be protected from other LNG facilities 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.
(3) Each control center shall have personnel in attendance while any of the components under its control are in operation, unless either the control is being performed from another control center that has personnel in attendance or the facility has an automatic emergency shutdown system.
(4) If more than one control center is located at an LNG plant, each control center shall have more than one means of communication with every other center.
(5) Each control center shall have a means of communicating a warning of hazardous conditions to other locations within the plant frequented by personnel.

4.4 Sources of Power.

4.4.1 Electrical control systems, means of communication, emergency lighting, and fire-fighting systems 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.

4.4.2 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.

4.5 Records.

4.5.1 Each plant shall have a record of materials of construction for components, buildings, foundations, and support systems used for containment of LNG and flammable fluids.

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

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

4.6* Noncombustible Material.

4.6.1 A material that complies with any of the following shall be considered a noncombustible material. [***101,*** 4.6.13.1]

(1)*A material that, in the form in which it is used and under the conditions anticipated, will not ignite, burn, support combustion, or release flammable vapors when subjected to fire or heat. [***101,*** 4.6.13.1(1)]
(2) A material that is reported as passing ASTM E 136, *Standard Test Method for Behavior of Materials in a Vertical Tube Furnace at 750 Degrees C.* [***101,*** 4.6.13.1(2)]
(3) A material that is reported as complying with the pass/fail criteria of ASTM E 136 when tested in accordance with the test method and procedure in ASTM E 2652, *Standard Test Method for Behavior of Materials in a Tube Furnace with a Cone-shaped Airflow Stabilizer, at 750 Degrees C.* [***101,*** 4.6.13.1(3)]

Chapter 5 Plant Siting and Layout

5.1 Scope. This chapter presents the criteria for plant and equipment siting.

5.2* Plant Site Provisions.

5.2.1 A written site evaluation addressing the following factors shall be prepared and made available to the authority having jurisdiction upon request:

(1) Potential incidents and mitigating measures
(2) Adjacent activities
(3) Severe weather patterns over a 100-year period
(4) Other natural hazards
(5) Security

5.2.2 All-weather accessibility to the plant for personnel safety and fire protection shall be provided except where provisions for personnel safety and fire protection are provided on the site in accordance with Chapter 12.

5.2.3 Site preparation shall include provisions for retention of spilled LNG, flammable refrigerants, and flammable liquids within the limits of plant property and for surface water drainage.

5.2.4* Soil and general investigations of the site shall be made to determine the design basis for the facility.

5.3 Site Provisions for Spill and Leak Control.

5.3.1 General.

5.3.1.1 Provisions shall be made to minimize the potential of accidental discharge of LNG at containers, pipelines containing LNG, and other equipment such that a discharge from any of these does not endanger adjoining property or important process equipment and structures or reach waterways. LNG 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 5.3.2 and 5.3.3
(2) An impounding area formed by a natural barrier, dike, excavation, impounding wall, or combination thereof complying with 5.3.2 and 5.3.3, plus a natural or man-made drainage system surrounding the container(s) that complies with 5.3.2 and 5.3.3
(3) Where the container is constructed below or partially below the surrounding grade, an impounding area formed by excavation complying with 5.3.2 and 5.3.3

5.3.1.2 The following areas shall be graded, drained, or provided with impoundment in a manner that minimizes the possibility of accidental spills and leaks that could endanger important structures, equipment, or adjoining property or that could reach waterways:

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

5.3.1.3 If impounding areas also are required in order to comply with 5.2.3, such areas shall be in accordance with 5.3.2 and 5.3.3.

5.3.1.4 The provisions of 5.2.3, 5.3.1.1, and 5.3.1.2 that apply to adjoining property or waterways shall be permitted to be waived or altered at the discretion of the authority having jurisdiction

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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.

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

5.3.2 Impounding Area and Drainage System Design and Capacity.

5.3.2.1 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

5.3.2.2 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

5.3.2.3 Enclosed drainage channels for LNG shall be prohibited except where they are used to rapidly conduct spilled LNG away from critical areas and they are sized for the anticipated liquid flow and vapor formation rates.

5.3.2.4 Where enclosed container down comers are used to rapidly conduct spilled LNG away from critical areas, they shall be sized for the anticipated liquid flow and vapor formation rates.

5.3.2.5 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 or flammable refrigerant, the effect of rapid cooling to the temperature of the liquid to be confined, any anticipated fire exposure, and natural forces, such as earthquakes, wind, and rain.
(2) Where the outer shell of a double-wall tank complies with the requirements of 5.3.1.1, the dike shall be either the outer shell or as specified in 5.3.1.1.
(3) Where the containment integrity of such an outer shell can be affected by an inner tank failure mode, an additional impounding area that otherwise satisfies the requirements of 5.3.1.1 shall be provided.

5.3.2.6 Double and full 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.

(A) In the case of a fire confined to the inner tank, the secondary container wall shall retain sufficient structural integrity to prevent collapse, which can cause damage to and leakage from the primary container.

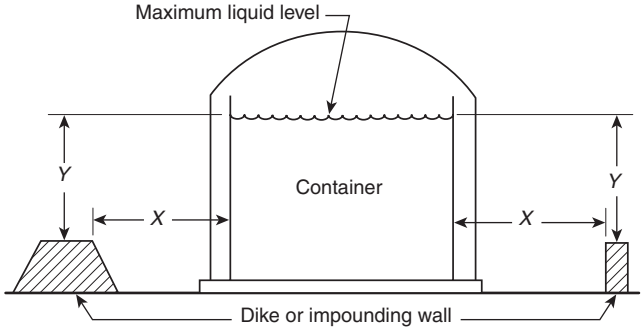
(B) The tanks shall also be designed and constructed such that in the case of a fire in the primary or secondary container of an adjacent tank, the secondary container shall retain sufficient structural integrity to prevent collapse, which can cause damage to and leakage from the primary container.

5.3.2.7 Double and full containment tank systems shall have no pipe penetrations below the liquid level.

5.3.2.8 Dikes, impounding walls, and drainage channels for flammable liquid containment shall conform to NFPA 30, *Flammable and Combustible Liquids Code*.

5.3.2.9 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.

5.3.2.10 The dike or impounding wall height and the distance from containers operating at 15 psi (103 kPa) or less shall be determined in accordance with Figure 5.3.2.10.



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.

FIGURE 5.3.2.10 Dike or Impoundment Wall Proximity to Containers.

5.3.2.11 Water Removal.

5.3.2.11.1 Impoundment areas shall be constructed such that all areas drain completely to prevent water collection.

(A) Drainage pumps and piping shall be provided to prevent water from collecting in the impoundment area.

(B) Impounding systems shall have sump pumps and piping running over the dike to remove water collecting in the sump basin.

5.3.2.11.2 The water removal system shall have capacity to remove water at a minimum of 25 percent of the rate from a

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storm of a 10-year frequency and 1-hour duration, except if the design of the dike does not allow the entrance of rainfall.

5.3.2.11.3 Sump pumps for water removal shall be as follows:

(1) Operated as necessary to keep the impounding space as dry as practical
(2) If sump pumps are designed for automatic operation, have redundant automatic shutdown controls to prevent operation when LNG is present

5.3.3 Impounding Area Siting.

5.3.3.1 The provisions of Section 5.3 shall not apply to impounding areas that serve only transfer areas at the water's edge of marine terminals.

5.3.3.2 The maximum radiant heat flux from a fire shall not exceed the limits listed in Table 5.3.3.2.

Table 5.3.3.2 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[a]
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 fire in an 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 fire in an impounding area[b,c]
10,000	30,000	A property line at ground level that can be built upon for a fire over an impounding area[b]

[a]See 5.3.3.7 for design spill.
[b]The requirements for impounding areas are located in 5.3.2.
[c]See NFPA *101, Life Safety Code*, or *NFPA 5000, Building Construction and Safety Code*, for definitions of occupancies.

5.3.3.3* The use of passive fire mitigation techniques in the calculation of radiant heat distances shall be subject to the approval of the AHJ.

5.3.3.4* The distances to the radiant heat flux levels of Table 5.3.3.2 shall be calculated in accordance with a model that:

(1) Takes into account the physical phenomena observed in, and has been validated with the data obtained from, available LNG fire experimental data, published in peer-reviewed scientific literature applicable to the physical situation considered
(2) Has been published in peer-reviewed scientific literature
(3) Has a scientific assessment verifying the details of the physics, analysis, and execution process
(4) Has been approved

5.3.3.5 Models employed in 5.3.3.4 shall incorporate the following:

(1) In calculating exclusion distances, the wind speed producing the maximum exclusion distances shall be used except for wind speeds that occur less than 5 percent of the time based on recorded data for the area.
(2) In calculating exclusion distances, the ambient temperature and relative humidity that produce the maximum exclusion distances shall be used except for values that occur less than 5 percent of the time, based on recorded data for the area.

5.3.3.6* The spacing of an LNG impoundment to the property line that can be built upon shall be such that, in the event of an LNG spill as specified in 5.3.3.7, a predicted concentration of methane in air of 50 percent of the lower flammability limit (LFL) does not extend beyond the property line that can be built upon, in accordance with a model that is acceptable for use by the authority having jurisdiction that has been evaluated by an independent body using the Model Evaluation Protocol facilities published by the Fire Protection Research Foundation report "Evaluating Vapor Dispersion Models for Safety Analysis of LNG Facilities."

(1) The computed distances shall include calculations based on one of the following:
  (a) The combination of wind speed and atmospheric stability that can occur simultaneously and result in the longest predictable downwind dispersion distance that is exceeded less than 10 percent of the time
  (b) The Pasquill-Gifford atmospheric stability, Category F, with a 4.5 mph (2 m/sec) wind speed
(2) The computed distances shall be based on the actual liquid characteristics and the maximum vapor outflow rate from the vapor containment volume (the vapor generation rate plus the displacement due to liquid inflow).
(3) The effects of provisions for detaining vapor or otherwise mitigating flammable vapor hazards (e.g., impounding surface insulation, water curtains, or other methods) shall be permitted to be considered in the calculation where acceptable to the authority having jurisdiction.
(4) Where provisions for detaining vapor or mitigating flammable vapor hazards are used, such as impounding surface insulation, water curtains, or other methods, they shall be approved.

5.3.3.7 The design spill shall be determined in accordance with Table 5.3.3.7.

5.3.3.8 LNG container 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.

5.3.3.9 Containers with an aggregate storage of 70,000 gal (265 m^3) or less on one site shall be installed either in accordance with 5.3.3 or in accordance with Table 5.3.4.1 where all connections are equipped with automatic fail-safe valves designed to close under any of the following conditions:

(1) Fire detection
(2) Excess flow of LNG from the container, as measured by loss of line pressure or other means

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Table 5.3.3.7 Design Spill

Design Spill Source	Design Spill Criteria	Design Spill Rate and Volume
Containers with Penetrations Below the Liquid Level		
Containers with penetrations below the liquid level without internal shutoff valves	A 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: $q = \frac{4}{3} d^2 \sqrt{h}$ until the differential head acting on the opening is 0. 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 9.4.2.5	The flow 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: $q = \frac{1.06}{10{,}000} d^2 \sqrt{h}$ for 10 minutes.
Containers with Over-the-Top Fill, with No Penetrations Below the Liquid Level		
Full or double containment containers with concrete secondary containers	No design spill	None
LNG Process Facilities		
Containers with over-the-top fill, with no penetrations below the liquid level	The largest flow from any single line that could be pumped into the impounding area with the container withdrawal pump(s) considered to be delivering the full-rated capacity	The largest flow from any single line that could be pumped into the impounding area with the container withdrawal pump(s) delivering the full rated capacity as follows: (1) For 10 minutes if surveillance and shutdown is demonstrated and approved by the authority having jurisdiction (2) For the time needed to empty a full container where surveillance and shutdown is not approved
Impounding areas serving only vaporization, process, or LNG transfer areas	The flow from any single accidental leakage source	For 10 minutes or for a shorter time based on demonstrable surveillance and shutdown provisions acceptable to the authority having jurisdiction

Note: q = flow rate [ft^3/min (m^3/min)] of liquid; d = diameter [in. (mm)] of tank penetration below the liquid level; h = height [ft (m)] of liquid above penetration in the container when the container is full.

(3) Gas detection
(4) Manual operation from both a local and a remote location

(A) The appurtenances shall be installed as close to the container as practical and so that a break resulting from external strain occurs on the piping side of the appurtenance while retaining intact the valve and piping on the container side of the appurtenance.

(B) Connections used only for flow into the container shall be equipped with an automatic fail-safe valve or with two backflow check valves.

(C) Automatic fail-safe valves shall not be required for connections for relief valves and instrument valves.

(D) The type, quantity, and location of the detection devices shall be in accordance with the requirements of Chapter 12.

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5.3.3.10 The distance from the nearest edge of impounded liquid to a property line that can be built upon or from the near edge of a navigable waterway as defined by federal regulations shall not be less than 50 ft (15 m).

5.3.4 Container Spacing.

5.3.4.1 The minimum separation distance between any type of LNG container of 70,000 gal (265 m^3) water capacity or less, single containment constructed LNG containers of greater than 70,000 gal (265 m^3) water capacity, or tanks containing flammable refrigerants and exposures shall be in accordance with Table 5.3.4.1 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.

5.3.4.2 Full and double construction LNG storage containers of greater than 70,000 gal (265 m^3) water capacity shall be separated from adjoining LNG storage containers such that a fire in one container or impoundment will not cause loss of containment from adjacent containers. This shall be accomplished by ensuring that no part of the adjacent storage container roof, walls, or its impoundment structure reaches a temperature at which the strength of the material of the container roof, wall, or its impoundment is reduced to a level where the LNG tank, roof, or impoundment loses its structural integrity. The application of engineering analyses shall be used to determine this temperature by including the following conditions in the analyses:

(1) The analyses shall be performed for the following:
   (a) A fire involving the complete loss of containment of a container to an impoundment area that complies with the requirements of 5.3.2.1
   (b) A fire over the whole surface of the liquid contained in the tank, assuming the roof is completely lost

(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) The atmospheric conditions producing the maximum separation distances shall be used except for conditions that occur less than 5 percent of the time based on recorded data for the area and using a LNG fire model in accordance with 5.3.3.4
   (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

5.3.4.3 The minimum separation distance between LNG containers and containers containing flammable refrigerants or from property lines that can be built upon shall be in accordance with Table 5.3.4.1.

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

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

5.3.5 Vaporizer Spacing.

5.3.5.1 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.

(A) 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.

Table 5.3.4.1 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.

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(B) 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.

5.3.5.2 Integral heated vaporizers shall be located at least 100 ft (30 m) from a property line that can be built upon *(see 5.3.5.4)* and at least 50 ft (15 m) from the following:

(1) Any impounded LNG, flammable refrigerant, or flammable liquid *(see 5.3.4)* or the paths of travel of such fluids between any other source of accidental discharge and the impounding area
(2) 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) Control buildings, offices, shops, and other occupied or important plant structures

5.3.5.3 Heaters or heat sources of remote heated vaporizers shall comply with 5.3.5.2.

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

5.3.5.5 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 5.3.4.1, assuming the vaporizer to be a container with a capacity equal to the largest container to which it is connected.

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

5.3.6 Process Equipment Spacing.

5.3.6.1 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.

5.3.6.2 Where control centers are located in a building housing flammable gas compressors, the building construction shall comply with 5.4.3.

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

5.3.7 Loading and Unloading Facility Spacing.

5.3.7.1 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.

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

5.3.7.3 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.

5.4 Buildings and Structures.

5.4.1 Buildings and Structures Design Category. Buildings and structures shall be classified in accordance with the following:

(1)*Classification I — Buildings and structures as defined in 7.4.4.6(3)
(2) Classification II. — Buildings and structures supporting or enclosing equipment and piping that contain flammable or toxic materials
(3) Classification III — All other buildings and structures

5.4.2 Buildings and Structures Design. Buildings and structures shall be designed for seismic, wind, ice and snow in accordance with 5.4.2.1 through 5.4.2.3.

5.4.2.1 Classification I. Seismic design shall use the operating basis earthquake (OBE) and safe shutdown earthquake (SSE) ground motions as defined in 7.4.4.3 and 7.4.4.4 for determination of loads to be used per ASCE 7, *Minimum Design Loads for Buildings and Other Structures*; wind, ice, and snow design shall use an occupancy category of IV per ASCE 7.

5.4.2.2 Classification II. Seismic, wind, ice, and snow design shall use an occupancy category of III per ASCE 7.

5.4.2.3 Classification III. Seismic, wind, ice, and snow design shall use an occupancy category of II per ASCE 7.

5.4.3 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.

5.4.4 If rooms containing LNG and flammable fluids are located within or attached to buildings in which such fluids are not handled (e.g., control centers, shops), the common walls shall be limited to no more than two, shall be designed to withstand a static pressure of at least 100 psf (4.8 kPa), shall have no doors or other communicating openings, and shall have a fire resistance rating of at least 1 hour.

5.4.5 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 5.4.5.1 through 5.4.5.4.

5.4.5.1 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

5.4.5.2 If there are basements or depressed floor levels, a supplemental mechanical ventilation system shall be provided.

5.4.5.3 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.

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5.4.5.4 If vapors heavier than air can be present, a portion of the ventilation shall be from the lowest level exposed to such vapors.

5.4.6 Buildings or structural enclosures not covered by 5.4.3 through 5.4.5 shall be located, or provision otherwise shall be made, to minimize the possibility of entry of flammable gases or vapors.

5.5* Designer and Fabricator Competence.

5.5.1 Supervision shall be provided for the fabrication of and for the acceptance tests of facility components to the extent necessary to ensure that they are structurally sound and otherwise in compliance with this standard.

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

5.5.3 Designers, fabricators, and constructors of LNG facility systems and equipment shall be competent in their respective fields.

5.5.4 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.

5.6* Soil Protection for Cryogenic Equipment. LNG containers *(see 7.3.7)*, 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.

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

5.8 Concrete Design and Materials.

5.8.1 Concrete used for construction of LNG containers shall be in accordance with 7.4.3.

5.8.2 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.

5.8.2.1 The design of the structures shall be in accordance with the provisions of 7.4.3.2.

5.8.2.2 The materials and construction shall be in accordance with the provisions of 7.4.3.2.

5.8.3 Structural concrete for pipe supports shall comply with Section 9.5.

5.8.4 Other Concrete Structures.

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

5.8.4.2 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 7.4.3.2.

5.8.5* 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.*

5.8.6 Minimum Reinforcement.

5.8.6.1 Reinforcement for concrete structures designed for LNG containment or cold vapor containment, other than those in 5.8.1 and 5.8.2; or for concrete structures covered in 5.8.3 and 5.8.4 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.*

5.8.6.2 Minimum reinforcement for concrete for incidental nonstructural uses covered in 5.8.5 shall be in accordance with the shrinkage and temperature reinforcement provisions of ACI 318, *Building Code Requirements for Structural Concrete and Commentary.*

5.8.7 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.

5.9 Portable LNG Facility.

5.9.1 Where portable 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) LNG transport vehicles complying with U.S. Department of Transportation (DOT) requirements shall be used as the supply container.
(2) All portable LNG equipment shall be operated by at least one person qualified by experience and training in the safe operation of these systems.
(3) All other operating personnel, at a minimum, shall be qualified by training.
(4) Each operator shall provide and implement a written plan of initial training to instruct all designated operating and supervisory personnel in the characteristics and hazards of LNG used or handled at the site, including low LNG temperature, flammability of mixtures with air, odorless vapor, boil-off characteristics, and reaction to water and water spray; the potential hazards involved in operating activities; and how to carry out the emergency procedures that relate to personnel functions and to provide detailed instructions on mobile LNG operations.
(5) 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.
(6) Portable or temporary containment means shall be permitted to be used.
(7) Vaporizer controls shall comply with 8.4.1, 8.4.2, and Section 8.5.
(8) Each heated vaporizer shall be provided with a means to shut off the fuel source remotely and at the installed location.
(9) Equipment and operations shall comply with 14.6.1, 14.6.2, Section 11.8, 11.9.1, 12.2.1, Section 12.3, 12.3.3, 12.3.4, 12.3.5, and 5.9.1(4), with the exception of the clearance distance provisions.
(10) The LNG facility spacing specified in Table 5.3.4.1 shall be maintained, except where necessary to provide temporary service on a public right-of-way or on property where clearances specified in Table 5.3.4.1 are not feasible and the following additional requirements are met:

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(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 5.9.1(10), flag persons shall be continuously on duty to direct such traffic.

(11) Provision shall be made to minimize the possibility of accidental ignition in the event of a leak.
(12) 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, *Standard for Portable Fire Extinguishers*.
(13) The site shall be continuously attended, and provisions shall be made to restrict public access to the site whenever LNG is present.

5.9.2 If odorization is required of the temporary facility, the restrictions of 5.3.4.1 shall not apply to the location of odorizing equipment containing 20 gal (7.6 L) or less of flammable odorant within the retention system.

Chapter 6 Process Equipment

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

6.2 Installation of Process Equipment.

6.2.1 Process system equipment containing LNG, flammable refrigerants, or flammable gases 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 5.4.3 through 5.4.5

6.2.2 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 6.5.2 through 6.5.5)*. Where equipment is not constructed to a specific standard, welding and brazing shall be in accordance with the requirements in 6.2.2(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*.

6.3 Pumps and Compressors.

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

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

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

6.3.4 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.

6.3.5 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.

6.3.6 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.

6.4 Flammable Refrigerant and Flammable Liquid Storage. Installation of storage tanks for flammable refrigerants and liquids shall comply with NFPA 30, *Flammable and Combustible Liquids Code*; NFPA 58, *Liquefied Petroleum Gas Code*; NFPA 59, *Utility LP-Gas Plant Code*; API 2510, *Design and Construction of Liquefied Petroleum Gas (LPG) Installations*; or Section 5.3 of this standard.

6.5 Process Equipment.

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

6.5.2 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*.

6.5.3 Pressure vessels shall be 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*, and shall be code-stamped.

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

6.5.5 Brazed aluminum plate fin heat exchangers shall be designed and fabricated in accordance with the ASME *Boiler and Pressure Vessel Code*, Section VIII, and ALPEMA *Standards of the Brazed Aluminum Plate Fin Heat Exchanger Manufacturers Association*.

6.5.6* Installation of internal combustion engines or gas turbines not exceeding 7500 horsepower per unit shall conform to NFPA 37, *Standard for the Installation and Use of Stationary Combustion Engines and Gas Turbines*.

6.5.7 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.

6.5.7.1 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.

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

6.5.8 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.

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Chapter 7 Stationary LNG Storage

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

7.2 General.

7.2.1 Storage Tank Systems.

7.2.1.1 Storage tank systems shall comply with the requirements of API 625, *Tank Systems for Refrigerated Liquefied Gas Storage*, and the additional provisions of this chapter.

7.2.1.2 Metal containers that are part of an LNG storage tank system shall comply with API 620, *Design and Construction of Large, Welded, Low-Pressure Tanks*, and the further requirements in 7.4 below.

7.2.1.3 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 7.4.

7.2.1.4 Should any conflict exist between the above requirements, the most stringent requirement shall apply.

7.2.2 ASME containers shall comply with the requirements of 7.5.

7.3 Design Considerations.

7.3.1 General.

7.3.1.1 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).

7.3.1.2 All piping that is a part of an LNG tank system shall comply with requirements in this chapter and requirements within API 625.

(A) 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 instrumentation (including tank 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 psig (345 kPa). Double and full containment tank systems shall have no pipe penetrations below the liquid level.

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

(C) Piping that is a part of an ASME LNG container, including piping between the inner and outer containers, shall be in accordance with either the ASME *Boiler and Pressure Vessel Code*, Section VIII, or with ASME B 31.3, *Process Piping*.

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

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

7.3.1.4 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.

7.3.1.5 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.

7.3.1.6 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).

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

7.3.2 Wind, Flood, and Snow Loads.

7.3.2.1 The wind, flood, and snow loads for the design of LNG tank systems and storage containers in the United States shall be determined using the procedures outlined in ASCE 7, *Minimum Design Loads for Buildings and Other Structures*.

7.3.2.2 For flood and snow loads, where a probabilistic approach is used, a 100-year mean occurrence interval shall be used.

7.3.2.3 Basic design wind speed shall be based on ASCE 7 for risk category IV structures.

7.3.2.4 The wind, flood, and snow loads used for the design of LNG storage containers in other countries shall be determined using either ASCE 7, or the values in the national code of the country.

7.3.3 Container Insulation.

7.3.3.1 Exposed insulation shall be noncombustible, shall contain or inherently shall be a vapor barrier, shall be waterfree, and shall resist dislodgment by fire hose streams.

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

(B) Exposed weatherproofing shall have a flame spread index not greater than 25. *(See 3.3.12.)*

7.3.3.2 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.

(A) A fire external to the outer tank shall not cause reduction of the insulation thermal conductivity due to melting or settling.

(B) 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.

(C) Only materials used between the inner and outer tank bottoms (floors) shall not be required to meet the combustibility requirements, where the material and the design of the installation comply with all of the following:

(1) The flame spread index of the material shall not exceed 25, and the material shall not support continued progressive combustion in air.

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(2) The material shall be of such composition that surfaces that would be exposed by cutting through the material on any plane shall have a flame spread index not greater than 25 and shall not support continued progressive combustion.
(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.
(4) The materials in the installed condition shall be demonstrated to be capable of being purged of natural gas.
(5) The natural gas remaining after purging shall not be significant and shall not increase the combustibility of the material.

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

7.3.4 Marking of LNG Storage Tank Systems and ASME Containers.

7.3.4.1 Each storage tank system shall be identified by the attachment in an accessible location of a corrosion-resistant nameplate as defined in API 625.

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

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

7.3.4.4 Penetration markings shall be visible if frosting occurs.

7.3.5 Container Purging and Cooldown.

7.3.5.1 Before an LNG tank system is put into service, it shall be purged and cooled in accordance with 14.3.5 and 14.5.5 and tank systems shall include the provisions within API 625 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 construction.

7.3.6 Relief Devices.

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

7.3.6.2 Relief devices shall communicate directly with the atmosphere.

7.3.6.3 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.

7.3.6.4 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.

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

(B) 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.

(C) 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.

(D) No more than one stop valve shall be closed at one time.

(E) 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.

7.3.6.5 Pressure Relief Device Sizing.

7.3.6.5.1 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

7.3.6.5.2 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.

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

7.3.6.6 Vacuum Relief Sizing.

7.3.6.6.1 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

7.3.6.6.2 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.

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

7.3.6.7 Fire Exposure.

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

For U.S. customary units:

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

For SI units:

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

where:
H = total heat influx [Btu/hr (watt)]
F = environmental factor from Table 7.3.6.7.1
A = exposed wetted surface area of the container [ft^2 (m^2)]
H_n = normal heat leak in refrigerated tanks [Btu/hr (watt)]

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Table 7.3.6.7.1 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 · ft^2 ·°F) [W/(m^2 ·°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).

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

7.3.6.7.3* 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.

7.3.6.7.4 Pressure Relief Valve Capacity.

(A) The relieving capacity shall be determined by the following formula:

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

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)

(B) The equivalent airflow shall be calculated from the following formulas:

For U.S. customary units:

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

For SI units:

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

where:
Q_a = equivalent flow capacity of air at 60°F (15°C) and absolute pressure of 14.7 psi (101 kPa) [ft^3/hr (m^3/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)]

7.3.7 Foundations.

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

7.3.7.2 Storage tank systems foundations shall be designed in accordance with ACI 376.

7.3.7.3 Prior to the start of design and construction of the foundation, a subsurface investigation and evaluation shall be conducted by a soils engineer to determine the stratigraphy and physical properties of the soils underlying the site. A liquefaction evaluation in accordance with 11.8.3 of ASCE 7 shall be included as part of the above evaluation.

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

7.3.7.5 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

7.3.7.6 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.

(A) The heating system shall be designed to allow functional and performance monitoring.

(B) 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.

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

(D)* Provisions shall be incorporated to prevent moisture accumulation in the conduit.

7.3.7.7 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.

7.3.7.8 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.

7.3.7.9 The system in 7.3.7.8 shall be used to conduct a container bottom temperature survey 6 months after the container has been placed in service and annually thereafter, after an operating basis earthquake (OBE), and after the indication of an abnormally cool area.

7.4 Tank Systems.

7.4.1 General.

7.4.1.1* 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 NFPA 59A.

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7.4.2 Metal Containers.

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

7.4.2.2* API 620, Appendix Q, shall be applicable for LNG with the following changes. 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.

7.4.3 Concrete Containers.

7.4.3.1 The design, construction, inspection, and testing of concrete containers shall comply with ACI 376.

7.4.3.2 Tanks with unlined concrete primary liquid containment shall include a means of detecting and eliminating liquid accumulation in the annular space.

7.4.3.3 Non-metallic coatings placed on a concrete container acting as a moisture and/or product vapor barrier shall meet the criteria in ACI 376.

7.4.3.4 Metallic barriers incorporated in, and functioning compositely with, concrete containers shall be of a metal defined in API 620, Appendix Q.

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

7.4.4.1 A site-specific investigation shall be performed for all installations except those provided for in 7.5.2 to determine the characteristics of seismic ground motion and associated response spectra.

(A) The site-specific investigation performed in accordance with ASCE 7, Chapter 21 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.

(B) 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, Chapter 21.

(C) 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.

(D) 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 API 620, Appendix L, and ACI 376, Chapter 6.

(E) 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. If information is available, the corresponding ratio shall not be less than one-half.

7.4.4.2 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 7.4.4.3
(2) Operating basis earthquake (OBE) as defined in 7.4.4.4
(3) Aftershock level earthquake (ALE) as defined in 7.4.4.5

7.4.4.3 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 7.4.4.1.

7.4.4.4* 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). 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. If a site-specific analysis is carried out, the OBE spectra shall not be less than 80 percent of the USGS spectra adjusted for local site conditions.

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

7.4.4.6 The three levels of ground motion defined in 7.4.4.3 through 7.4.4.5 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 7.4.4.6(1) or 7.4.4.6(2)

(A) The structures and systems shall be designed to remain operable during and after an OBE.

(B) The OBE design shall be based on a response reduction factor equal to 1.0.

(C) The SSE design shall provide for no loss of containment capability of the primary container, and it shall be possible to isolate and maintain the LNG tank system during and after the SSE

(D) Where used, response reduction factors applied in the SSE design shall be demonstrated not to reduce the performance criteria in 7.4.4.6(C). The values in API 620, Appendix L, are deemed to comply.

7.4.4.7 The secondary liquid container or impounding system 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 625.

7.4.4.8 An LNG tank system shall be designed for the OBE, SSE, and ALE in accordance with API 620 and ACI 376.

7.4.4.9 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.

7.4.4.10 The design of the LNG tank systems and structural components shall be in accordance with API 620 or ACI 376. Soil-structure interaction (SSI) shall be included where the tank system is not founded on bedrock (Site Class A or B per ASCE 7). SSI is permitted to be performed in accordance with the requirements of ASCE 7, Chapter 19.

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

7.4.5 Inspection.

7.4.5.1 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.

7.4.5.2 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.

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

7.4.6 Testing of LNG Containers.

7.4.6.1 LNG primary containers shall be hydrostatically tested and leak tested in accordance with the governing construction code or standard, and all leaks shall be repaired.

7.4.6.2 LNG concrete primary containers shall be hydrotested to a liquid height equal to the design liquid height times the product design specific gravity times 1.25 and applying an overload pressure of 1.25 times the pressure for which the vapor space is designed.

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

7.4.6.4 After acceptance tests are completed, there shall be no field welding on the LNG containers, except as permitted in 7.4.6.4(A) and (B).

(A) Field welding shall be limited to saddle plates or brackets provided for the purpose and to repairs permitted under the code or standard of fabrication.

(B) 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.

7.5 ASME Containers Designed for Operation at More Than 15 psi (103 kPa).

7.5.1 General.

7.5.1.1 Containers shall be double-walled, with the inner tank holding the LNG surrounded by insulation contained in the outer tank.

7.5.1.2 The insulation shall be evacuated or purged.

7.5.1.3 The inner tank 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.

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

(B) 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.

(C) 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.

7.5.1.4 The outer container shall be of welded construction.

(A) 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 Table 1A of the ASME *Boiler and Pressure Vessel Code*, Section II, Part D
(2) Materials with a melting point below 2000°F (1093°C) where the container is buried or mounded

(B) Where vacuum is utilized for insulation purposes , the outer container shall be designed by either of the following:

(1) The ASME *Boiler and Pressure Vessel Code*, Section VIII, Parts UG-28, UG-29, UG-30, and UG-33, 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*

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

(D) The maximum allowable working pressure shall be specified for all components.

(E) 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 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.

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

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

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

(I) 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.

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

7.5.1.6 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.

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7.5.1.7 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.

(A) Bellows shall not be permitted within the insulation space.

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

(C) 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.

(D) Transition joints shall not be prohibited.

7.5.1.8 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).

7.5.1.9 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.

7.5.2 Seismic Design of Land-Based Shop-Built Containers.

7.5.2.1 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:

$$V = Z_c \times W$$

For design vertical force, P:

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

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, 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

(A) 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 second.

(B) For periods of vibration greater than 0.06 second, the method of design in 7.4.4 shall be followed.

7.5.2.2 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.

7.5.2.3 The requirements of 7.5.2 shall apply to ASME containers built prior to July 1, 1996, when reinstalled.

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

7.5.3 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.

7.5.4 Testing of ASME LNG Containers.

7.5.4.1 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 9.7.
(5) Containers and associated piping shall be leak tested prior to filling the container with LNG.

7.5.4.2 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.

7.5.4.3 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.

Chapter 8 Vaporization Facilities

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

8.2 Classification of Vaporizers.

8.2.1 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.

8.2.2 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.

8.3 Design and Materials of Construction.

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

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8.3.2 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.

8.4 Vaporizer Piping, Intermediate Fluid Piping, and Storage Valves.

8.4.1 Manifolded vaporizers shall have both inlet and discharge block valves at each vaporizer.

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

8.4.3 Isolation of an idle manifolded vaporizer shall be by two inlet valves.

8.4.3.1 The LNG or gas that can accumulate between the valves or other double-block-and-bleed systems shall be piped to an area having no source of ignition and where people are not present.

8.4.4 A shutoff valve shall be installed on the LNG line to a heated vaporizer at least 50 ft (15 m) from the vaporizer.

8.4.4.1 If the heated vaporizer is installed in a building, the shutoff valve shall be installed at least 50 ft (15 m) from the building.

8.4.4.2 The shutoff valve shall be either the container shutoff valve or another valve.

8.4.5 Each heated vaporizer shall be provided with a local and a remote device to shut off the heat source.

8.4.5.1 Where the heated vaporizer is located 50 ft (15 m) or more from the heat source, the remote shutoff location shall be at least 50 ft (15 m) from the vaporizer.

8.4.5.2* Where the heated vaporizer is located less than 50 ft (15 m) from the heat source, it shall have an automatic shutoff valve in the LNG liquid line located at least 10 ft (3 m) from the vaporizer and shall close when any of the following occurs:

(1) Loss of line pressure (excess flow)
(2) Fire in the immediate vicinity of the vaporizer
(3) Low temperature in the vaporizer discharge line

8.4.5.3 If the facility is attended, manual operation of the automatic shutoff valve shall be from a point at least 50 ft (15 m) from the vaporizer, in addition to the requirements in 8.4.5.2.

8.4.6 Any ambient vaporizer or a heated vaporizer installed within 50 ft (15 m) of an LNG container shall be equipped with an automatic shutoff valve in the LNG liquid line.

8.4.6.1 The automatic shutoff valve shall be located at least 10 ft (3 m) from the ambient or heated vaporizer and shall close in any one of the following situations:

(1) Loss of line pressure (excess flow)
(2) Fire in the immediate vicinity of the vaporizer
(3) Low temperature in the vaporizer discharge line

8.4.6.2 If the facility is attended, manual operation of the automatic shutoff valve shall be from a point at least 50 ft (15 m) from the vaporizer, in addition to the requirements of 8.4.6.1.

8.4.7 Automatic equipment shall be provided to prevent the discharge of either LNG or vaporized gas into a piping system at a temperature either above or below the design temperatures of the system.

8.4.7.1 Automatic equipment shall be independent of all other flow control systems.

8.4.7.2 Automatic equipment shall incorporate a line valve for emergency purposes.

8.4.8 Where a flammable intermediate fluid is used with a remote heated vaporizer, shutoff valves shall be in accordance with the following:

(1) Shutoff valves shall be provided on both the hot and the cold lines of the intermediate fluid system.
(2) Shutoff valve controls shall be located at least 50 ft (15 m) from the vaporizer.

8.5 Relief Devices on Vaporizers.

8.5.1 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.

8.5.2 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.

8.5.3 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.

8.6 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.

8.7 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.

Chapter 9 Piping Systems and Components

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

9.2 General.

9.2.1* Process piping systems within the scope of ASME B 31.3, *Process Piping*, except those that are part of or within an LNG Container shall be in accordance with ASME B 31.3.

9.2.1.1 The additional provisions of this chapter supplement those in ASME B 31.3 and shall apply to piping systems and components for flammable liquids and flammable gases.

9.2.1.2 Fuel gas systems shall be in accordance with NFPA 54, *National Fuel Gas Code*, or ASME B 31.3.

9.2.1.3 Fire protection system piping shall meet the applicable NFPA standards in Section 2.2.

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9.2.2 Seismic Design Requirements.

9.2.2.1 For purposes of design, all piping of the LNG facility shall be classified into one of the following three seismic categories:

(1) Category I — All piping supported by the LNG container and piping up to the emergency shutdown valve(s) and firewater piping
(2) Category II — All flammable gas or LNG process piping
(3) Category III — All other piping not included in Categories I and II

9.2.2.2 Piping categories shall be in accordance with the following:

(1) Category I — All Category I piping shall be designed for the OBE and SSE event. For the OBE design, response modifications shall not be used.
(2) Category II — All Category II piping shall be designed for the design earthquake per ASCE 7, *Minimum Design Loads for Buildings and Other Structures*. At maximum, a response modification factor R_p of 6 shall be used. The importance value I_p shall be taken as 1.5.
(3) Category III — All Category III piping shall be designed for the design earthquake per ASCE 7.

9.2.2.3 Piping shall be analyzed using an equivalent static analysis or a dynamic analysis meeting the requirements of ASCE 7. 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

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

9.2.4 Provision for expansion and contraction of piping and piping joints due to temperature changes shall be in accordance with ASME B 31.3, Section 319.

9.3 Materials of Construction.

9.3.1 General.

9.3.1.1 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.

9.3.1.2 Piping that can be exposed to the low temperature of an LNG or refrigerant spill or the heat of an ignited spill 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 spill during the emergency

9.3.1.3 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 E 84, *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.

9.3.1.4* In addition to 9.3.1.3, 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 E 136, *Standard Test Method for Behavior of Materials in a Vertical Tube Furnace at 750°C* (see 4.6)
(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, *Standard Test Method to Evaluate Fire Performance Characteristics of Pipe Insulation*.

9.3.2 Piping.

9.3.2.1 Furnace lap-welded and furnace butt-welded pipe shall not be used.

9.3.2.2 All piping material shall either meet the requirements in Chapter III of ASME B 31.3 or conform with ASME B 31.3, paragraphs 323.1.2 and 323.2.3 and be documented in the engineering design.

9.3.2.3 All piping components shall either meet the requirements in Chapter III of ASME B 31.3 or conform with ASME B 31.3, paragraphs 326.1.2 and 326.2.2 and be documented in the engineering design.

9.3.2.4 Threaded pipe shall be at least Schedule 80.

9.3.2.5 A liquid line on a storage 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).

9.3.2.5.1 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 9.3.2.5.

9.3.2.6 Transition Joints.

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

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

9.3.2.7 Cast iron, malleable iron, and ductile iron pipe shall not be used.

9.3.3 Fittings.

9.3.3.1 Threaded nipples shall be at least Schedule 80.

9.3.3.2 Cast iron, malleable iron, and ductile iron fittings shall not be used.

9.3.3.3* Bends.

(A) Bends shall be permitted only in accordance with ASME B 31.3, Section 332. Corrugated and creased bends shall be prohibited.

(B) 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 B 31.3 are used to verify each bend
(4) All bending and forming of piping material shall meet the requirements of ASME B 31.3, Section 332, except that corrugated and creased bends shall be prohibited

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

9.3.3.5 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 ASME B 31.3, Section 315.

9.3.4 Valves.

9.3.4.1 Valves shall comply with one of the following:

(1) ASME B 31.3, paragraph 307.1.1
(2) ASME B 31.5, ASME B 31.8 or API 6D, *Specification for Pipeline Valves,* where suitable for the design conditions
(3) ASME B 31.3, paragraph 307.1.2, where documented in the engineering design

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

9.4 Installation.

9.4.1 Piping Joints.

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

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

9.4.1.3 Tubing joints shall be in accordance with paragraph 315 in ASME B 31.3.

9.4.1.4 The following pipe joints are prohibited:

(1) Expanded joints per ASME B 31.3, paragraph 313.
(2) Caulked joints per ASME B 31, paragraph 3.316.
(3) Special joints per ASME B 31.3, paragraph 318.

9.4.1.5 Special components that are unlisted per ASME B 31.3 paragraph 304.7.2, shall be based on design calculations consistent with the design criteria of ASME B 31.3. Calculations shall be substantiated by one or both of the means stated in ASME B paragraphs 31.3, 304.7.2 (a), 304.7.2(b), or both.

9.4.1.6 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.

9.4.1.7 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.

9.4.1.8 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

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

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

9.4.2* Valves.

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

9.4.2.2 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.

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

(1) Connections for relief valves in accordance with the ASME *Boiler and Pressure Vessel Code*, Section VIII, Division 1, UG-125(d) and Appendix M-5
(2) Connections for liquid level alarms as required by 10.2.1.3 or 13.15.2 if an ASME container
(3) Connections that are blind flanged or plugged

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

9.4.2.5 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.

9.4.2.6 In addition to the container shutoff valve required in 9.4.2.3, container connections larger than 1 in. (25 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

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

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

9.4.2.9* 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.

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

9.4.2.11 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.

9.4.3 Welding and Brazing. All pressure containment, ASME B 31.3 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*.

9.4.3.1 Qualification and performance of welders shall be in accordance with subsection 328.2 of ASME B 31.3, and 9.4.3.2 of this standard.

9.4.3.2 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.

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

9.4.3.4 Oxygen–fuel gas welding shall not be permitted.

9.4.3.5 Brazing and brazed connections shall be in accordance with subsections 317.2, 333.1, 333.2, 333.3, and 333.4 of ASME B 31.3.

9.4.3.6 Brazed connections which are part of an ASME B 31.3 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, Safeguarding, of ASME B 31.3. Brazed connections used for service temperatures colder than –20°F (–29°C) shall be specified in the engineering design and approved by the operator.

9.4.4 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.

9.5 Pipe Supports.

9.5.1 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.

9.5.2 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.

9.5.3 The design of supporting elements shall conform to ASME B 31.3, Section 321.

9.6* Piping Identification. Piping shall be identified by color coding, painting, or labeling.

9.7 Inspection, Examination, and Testing of Piping. Inspection, examination, and testing shall be performed in accordance with Chapter VI of ASME B 31.3 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 B 31.3, Normal Fluid Service.

9.7.1 Leak Testing.

9.7.1.1 Leak testing shall be conducted in accordance with ASME B 31.3, Section 345.

9.7.1.2 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.

9.7.2 Record Keeping.

9.7.2.1 A record of each leak test shall be made per paragraph 345.2.7 of ASME B 31.3.

9.7.3 Welded Pipe Examinations.

9.7.3.1 Longitudinal welded pipe that is subjected to minimum design temperatures below –20°F (–29°C) shall meet the following requirement:

(1) The longitudinal or spiral weld shall be subjected to 100 percent radiographic examination in accordance with paragraph 302.3.4 and Table A-1B of ASME B 31.3 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.

9.7.3.2 All circumferential butt-and-miter groove welds and branch connection welds comparable to Figure 328.5.4E in ASME B 31.3 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 B 31.3 except as modified by 9.7.3.2(A) and 9.7.3.2(B).

(A) 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 ASME B 31.3, subsection 344.2.

(B) Piping with minimum design temperature at or above –20°F (–29°C) shall have random 20 percent radiographic or ultrasonic examination of circumferential butt-and-miter groove welds and branch connection welds comparable to Figure 328.5.4E in accordance with Chapter VI, Sections 341 and 344 of ASME B 31.3.

9.7.3.3 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% examined visually and by liquid penetrant or magnetic particle examination in accordance with Chapter VI, Sections 341 and 344, of ASME B 31.3.

9.7.3.4* All branch connection welds not radiographed or ultrasonically examined , shall be 100 percent examined per ASME B 31.3 Chapter VI, Sections 341 and 344 as follows:

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(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.

9.7.4 Examination Criteria.

9.7.4.1 Nondestructive examination methods, limitations on defects, and the qualifications of the personnel performing and interpreting the examinations shall meet the requirements of ASME B 31.3, *Process Piping*, Chapter VI, Sections 341 through 344 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 ASME *Boiler and Pressure Vessel Code*, Section V, as applicable to the specific NDE method.

9.7.4.2 Substitution of in-process examination for radiographic or ultrasonic examination as permitted in ASME B 31.3, Paragraph 341.4.1, 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.

9.7.5 Record Retention.

9.7.5.1 Test and examination records and written procedures required within this standard and within ASME B 31.3, Paragraph 345.2.7 and Section 346 respectively, shall be maintained for the life of the piping system by the facility operator or until such time as a re-examination is conducted.

9.7.5.2 Records and certification pertaining to materials, components, and heat treatment as required by ASME B 31.3, Paragraph 341.4.1(c), 341.4.3(d), and Section 346 shall be maintained by the facility operator for the life of the system.

9.8 Purging of Piping Systems.

9.8.1* Systems shall be purged of air or gas.

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

9.9 Safety and Relief Valves.

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

9.9.1.1 Safety relief systems (piping and valves) shall be designed, installed, and tested in accordance with ASME B 31.3, subsection 322.6, and Section 9.9 of this standard in its entirety.

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

9.9.3 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.

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

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

9.10 Corrosion Control.

9.10.1* 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.*

9.10.2 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.

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

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

9.11 Cryogenic Pipe-in-Pipe Systems.

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

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

9.11.2 Inner Pipe. The inner pipe assembly shall be designed, fabricated, examined, and tested in accordance with ASME B 31.3, and inspection levels shall be specified. As a minimum, Normal Fluid Service requirements shall be met, unless specified otherwise in the engineering design.

9.11.3 Outer Pipe. The outer pipe assembly shall be designed, fabricated, examined, and tested in accordance with the requirements of ASME B 31.3.

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

9.11.3.2 If the outer pipe also functions as the secondary containment system, the outer pipe shall be designed to contain the inner pipe product and shall be designed, fabricated, examined, and tested in accordance with the requirements of ASME B 31.3.

9.11.4 Vacuum-Jacketed Function. If the outer pipe functions as a vacuum-jacketed system, then failure of the outer pipe shall not damage the inner pipe.

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9.11.4.1 If the outer jacket functions as the secondary containment system, the outer pipe jacket shall be designed to withstand and carry the full inner pipe product and shall be designed, fabricated, examined, and tested in accordance with the requirements of ASME B 31.3.

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

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

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

9.11.6 Operational Requirements.

9.11.6.1 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.

9.11.6.2 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.

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

9.11.8* Corrosion Protection.

9.11.8.1 The inner pipe and the annular space shall be considered to be non-corroding in its operating environment.

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

9.11.9 Installation.

9.11.9.1 Pipe, when buried on land, shall be buried to a minimum of 3 ft. (0.9 m) of cover.

9.11.9.2 Pipe, when buried in navigable waterways should be buried to minimum depth of 4 ft. (1.2 m) of cover.

9.11.9.3 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.

Chapter 10 Instrumentation and Electrical Services

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

10.2 Liquid Level Gauging.

10.2.1 LNG Containers.

10.2.1.1 LNG containers shall be equipped with two independent liquid level gauging devices that compensate for variations in liquid density.

10.2.1.2 Gauging devices shall be designed and installed so that they can be replaced without taking the container out of operation.

10.2.1.3 Each container shall be provided with two independent high-liquid-level alarms, which shall be permitted to be part of the liquid level gauging devices.

(A) 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 to personnel controlling the filling.

(B) The high-liquid-level flow cutoff device required in 10.2.1.4 shall not be considered as a substitute for the alarm.

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

10.2.2 Tanks for Refrigerants or Flammable Process Fluids.

10.2.2.1 Each storage tank shall be equipped with a liquid level gauging device.

10.2.2.2 If it is possible to overfill the tank, a high-liquid-level alarm shall be provided in accordance with 10.2.1.3.

10.2.2.3 The requirements of 10.2.1.4 shall apply to installations of flammable refrigerants.

10.3 Pressure Gauging. Each container shall be equipped with a pressure gauge connected to the container at a point above the maximum intended liquid level.

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

10.5 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.

10.5.1 Vaporizers shall be provided with indicators to monitor inlet and outlet temperatures of LNG, vaporized gas, and heating-medium fluids to ensure effectiveness of the heat transfer surface.

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

10.6 Emergency Shutdown. Instrumentation for liquefaction, storage, and vaporization facilities 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.

10.7 Electrical Equipment.

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

10.7.2* Fixed electrical equipment and wiring installed within the classified areas specified in Table 10.7.2 shall comply with Table 10.7.2 and Figure 10.7.2(a) through Figure 10.7.2(f) and shall be installed in accordance with *NFPA 70, National Electrical Code*, for hazardous locations.

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Table 10.7.2 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
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 10.7.2(c).]*
		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 10.7.2(b).]*
	Outdoor belowground containers	1	Within any open space between container walls and surrounding grade or dike *[See Figure 10.7.2(d).]*
		2	Within 15 ft (4.5 m) in all directions from roof and sides *[See Figure 10.7.2(d).]*
C	**Nonfired LNG process areas containing pumps, compressors, heat exchangers, pipelines, connections, small containers, and so forth**		
	Indoors with adequate ventilation[c]	2	Entire room and any adjacent room not separated by a gastight partition and 15 ft (4.5 m) beyond any wall or roof ventilation discharge vent or louver
	Outdoors in open air at or above grade	2	Within 15 ft (4.5 m) in all directions from this equipment and within the cylindrical volume between the horizontal equator of the sphere and grade *[See Figure 10.7.2(a).]*
D	**Pits, trenches, or sumps located in or adjacent to Division 1 or 2 areas**	1	Entire pit, trench, or sump
E	**Discharge from relief valves**	1	Within 5 ft (1.5 m) in all directions from point of discharge
		2	Beyond 5 ft (1.5 m) but within 15 ft (4.5 m) in all directions from point of discharge
F	**Operational bleeds, drips, vents, or drains**		
	Indoors with adequate ventilation[c]	1	Within 5 ft (1.5 m) in all directions from point of discharge
		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 point of discharge
		2	Beyond 5 ft (1.5 m) but within 15 ft (4.5 m) in all directions from point of discharge

(continues)

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Table 10.7.2 *Continued*

Part	Location	Group D, Division[a]	Extent of Classified Area
G	**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 *[See Figure 10.7.2(a).]*
H	**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
I	**Marine terminal unloading areas** *[See Figure 10.7.2(f).]*		

[a]See Article 500 in *NFPA 70, National Electrical Code*, for definitions of classes, groups, and divisions. Article 505 may 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 10.7.2. 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 available electrical equipment for hazardous locations is suitable for both groups.
[b]Small containers are those that 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.

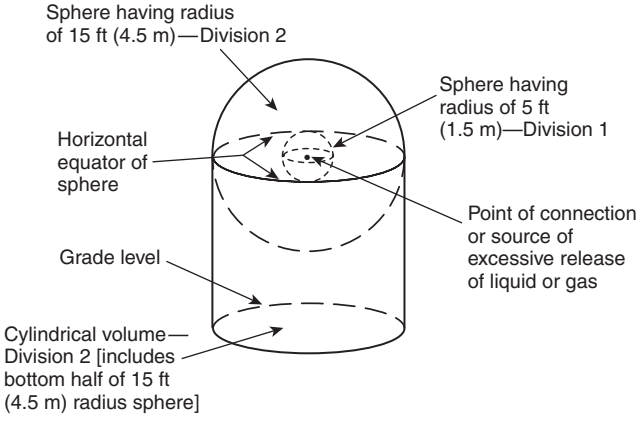


FIGURE 10.7.2(a) Extent of Classified Area Around Containers.

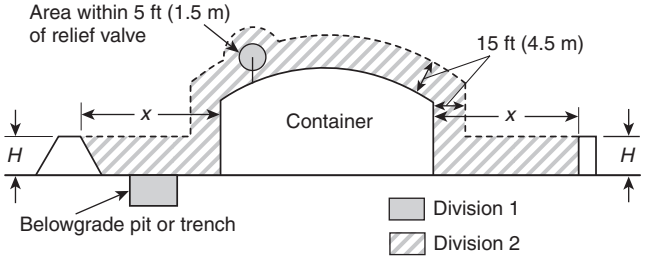


FIGURE 10.7.2(b) Dike Height Less Than Distance from Container to Dike ($H < x$).

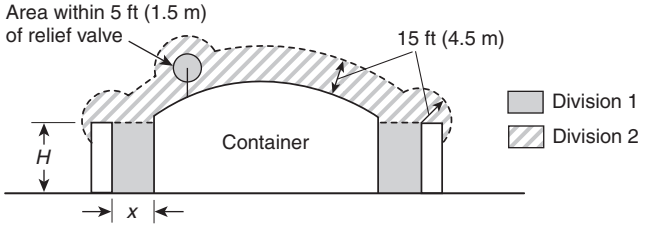


FIGURE 10.7.2(c) Dike Height Greater Than Distance from Container to Dike ($H > x$).

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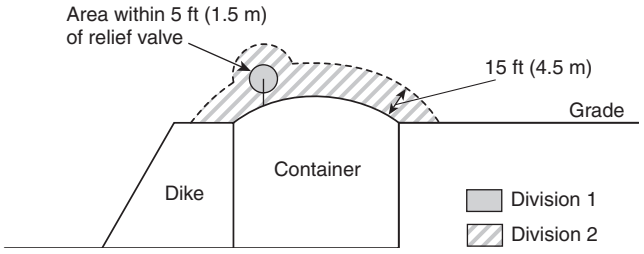


FIGURE 10.7.2(d) Container with Liquid Level Below Grade or Below Top of Dike.

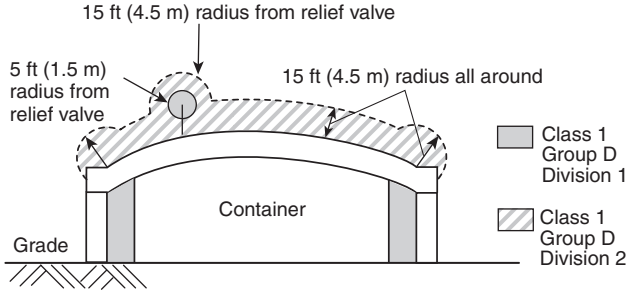


FIGURE 10.7.2(e) Full Containment Container.

10.7.3 Electrically classified areas shall be as specified in Table 10.7.2.

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

(B) The extent of the electrically classified areas shall be measured in accordance with Table 10.7.2.

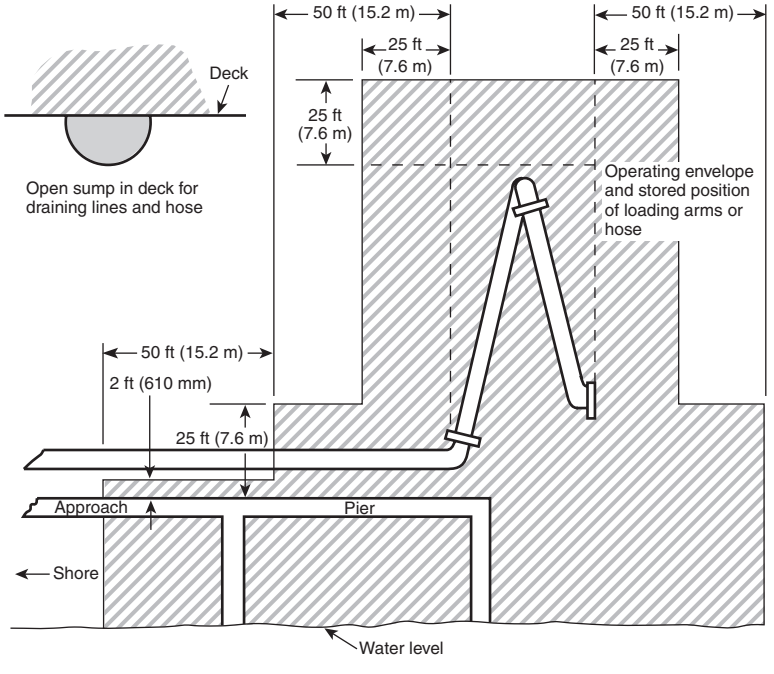
10.7.4 The interior of an LNG container shall not be a classified area where the following conditions are met:

(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.

10.7.5 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.

10.7.5.1 Each seal, barrier, or other means used to comply with 10.7.5 shall be designed to prevent the passage of flammable fluids through the conduit, stranded conductors, and cables.

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





Notes:
(1) The "source of vapor" is the operating envelope and stored position of the outboard flange connection of the loading arm (or hose).
(2) The berth area adjacent to tanker and barge cargo tanks is to be Division 2 to the following extent:
  (a) 25 ft (7.6 m) horizontally in all directions on the pier side from the portion of the hull containing cargo tanks.
  (b) From the water level to 25 ft (7.6 m) above the cargo tanks at their highest position.
(3) Additional locations can be classified as required by the presence of other sources of flammable liquids on the berth, or by Coast Guard or other regulations.

FIGURE 10.7.2(f) Classification of a Marine Terminal Handling LNG.

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(A) 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.

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

(C) 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.

10.7.5.3 Secondary Seal.

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

(B) Similar provisions to 10.7.5.3(A) shall be made on double-integrity primary sealant systems of the type used for submerged motor pumps.

(C) The requirements of 10.7.5.3(A) shall apply to double-integrity primary sealant systems.

10.7.5.4 The seals specified in 10.7.5 and 10.7.6 shall not be used to meet the conduit sealing requirements of *NFPA 70*, *National Electrical Code*, or CSA C 22.1.

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

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

10.8 Electrical Grounding and Bonding.

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

10.8.2 Static protection shall not be required where tank cars, tank vehicles, or marine equipment are loaded or unloaded and where both halves of metallic hose couplings or pipe are in contact.

10.8.3* 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.

10.8.4* Lightning protection ground rods shall be provided for tanks supported on nonconductive foundations.

Chapter 11 Transfer Systems for LNG, Refrigerants, and Other Flammable Fluids

11.1 Scope. This chapter applies to the design, construction, and installation of systems involved in the transfer of LNG, refrigerants, flammable liquids, and flammable gases between storage containers or tanks and points of receipt or shipment by pipeline, tank car, tank vehicle, or marine vessel.

11.2 General Requirements.

11.2.1 Loading and unloading areas shall be posted with signs that read "No Smoking."

11.2.2 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.

11.2.3 Purging of systems described in Section 11.1, when necessary for operations or maintenance, shall meet the requirements in 14.5.5.

11.3 Piping System.

11.3.1 Isolation valves shall be installed at the extremity of each transfer system.

11.4 Pump and Compressor Control.

11.4.1 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.

11.4.2 Remotely located pumps and compressors used for loading or unloading tank cars, tank vehicles, 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.

11.4.3 Controls located aboard a marine vessel shall be considered to be in compliance with 11.4.2.

11.4.4 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.

11.5 Marine Shipping and Receiving.

11.5.1 Berth Design Requirements.

11.5.1.1 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

11.5.2 Piping (or Pipelines).

11.5.2.1 Pipelines 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.

11.5.2.2 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.

11.5.2.3 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.

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(A) 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.

(B) 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.

(C) 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.

(D) Valves shall be located at the point of hose or arm connection to the manifold.

(E) Bleeds or vents shall discharge to a safe area.

11.5.2.4 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.

(A) Where more than one line is involved, the valves shall be grouped in one location.

(B) Valves shall be identified for their service.

(C) Valves 8 in. (200 mm) and larger shall be equipped with powered operators.

(D) Means for manual operation shall be provided.

11.5.2.5 Pipelines used only for liquid unloading shall be provided with a check valve located at the manifold adjacent to the manifold isolation valve.

11.5.2.6 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.

11.5.3* 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

11.6 Tank Vehicle and Tank Car Loading and Unloading Facilities.

11.6.1 Transfer shall be made only into tank cars approved for the service.

11.6.2 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, *Liquefied Petroleum Gas Code.*
(3) Flammable liquid tank vehicles shall comply with NFPA 385, *Standard for Tank Vehicles for Flammable and Combustible Liquids.*

11.6.3 A rack structure, if provided, shall be constructed of a noncombustible material.

11.6.4 A tank vehicle loading and unloading area shall be of sufficient size to accommodate the vehicles without excessive movement or turning of the vehicles.

11.6.5 Transfer piping, pumps, and compressors shall be located or protected by barriers so that they are protected from damage by rail or vehicle movements.

11.6.6 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.

11.6.7 Bleeds or vents shall discharge to a safe area.

11.6.8 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.

11.6.8.1 Emergency valves shall be readily accessible for emergency use.

11.6.8.2 Where a common line serves multiple loading or unloading areas, only one emergency valve shall be required.

11.6.8.3 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.

11.6.9 Pipelines used only for liquid unloading shall have a check valve at the manifold adjacent to the manifold isolation valve.

11.7 Pipeline Shipping and Receiving.

11.7.1 Isolation valves shall be installed at all points where transfer systems connect into pipeline systems.

11.7.2 The pipeline system shall be designed so that it cannot exceed its temperature or pressure limits.

11.7.3 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.

11.7.4 Bleed or vent connections shall be provided so that loading arms and hoses can be drained and depressurized prior to disconnecting.

11.7.5 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.

11.8 Hoses and Arms.

11.8.1 Hoses or arms used for transfer shall be designed for the temperature and pressure conditions of the loading or unloading system.

11.8.2 Hoses shall be approved for the service and shall be designed for a bursting pressure of at least five times the working pressure.

11.8.3 Flexible metallic hose or pipe and swivel joints shall be used where operating temperatures can be below –60°F (–51°C).

11.8.4 Loading arms used for marine loading or unloading shall have alarms to indicate that the arms are approaching the limits of their extension envelopes.

11.8.5 Counterweights shall be selected to operate with ice formation on uninsulated hoses or arms.

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11.8.6 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.

11.8.7 Marine loading or unloading operations shall be periodically tested as required by the authority having jurisdiction.

11.9 Communications and Lighting.

11.9.1 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.

11.9.2 Facilities transferring LNG during hours of darkness shall have lighting at the transfer area.

11.9.3 The LNG marine transfer area for LNG shall have a ship-to-shore communication system and a separate emergency ship-to-shore communication system.

11.9.4 The communication system required in 11.9.3 shall be continuously monitored both aboard ship and at the terminal.

Chapter 12 Fire Protection, Safety, and Security

12.1 Scope.

12.1.1 This chapter covers equipment and procedures designed to minimize the consequences from released LNG, flammable refrigerants, flammable liquids, and flammable gases in facilities constructed and arranged in accordance with this standard.

12.1.2 The provisions in Chapter 12 augment the leak and spill control provisions in other chapters.

12.1.3 This chapter includes basic plant security provisions.

12.2* General. Fire protection shall be provided for all LNG facilities.

12.2.1* 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.

12.2.2* 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, flammable refrigerants, or flammable gases
(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 ESD system, including analysis of subsystems, if any, and the need for depressurizing specific vessels or equipment during a fire emergency
(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 protective equipment, special training, and qualification needed by individual plant personnel as specified by NFPA 600, *Standard on Industrial Fire Brigades*, for their respective emergency duties
(10) Requirements for other fire protection equipment and systems

12.3 Emergency Shutdown (ESD) Systems.

12.3.1 Each LNG facility shall have an ESD system(s) to isolate or shut off a source of LNG, flammable liquids, flammable refrigerant, or flammable gases, and to shut down equipment whose continued operation could add to or sustain an emergency.

12.3.2 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.

12.3.3 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.

12.3.4 The ESD system(s) shall be of a fail-safe design or shall be otherwise 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.

12.3.5 ESD systems that are not of a fail-safe design shall have all components that are located within 50 ft (15 m) of the equipment controlled 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 duration

12.3.6 Operating instructions identifying the location and operation of emergency controls shall be posted in the facility area.

12.3.7 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.

12.4 Fire and Leak Detection.

12.4.1 Areas, including enclosed buildings, that can have the presence of flammable gas, LNG or flammable refrigerant spills, and fire shall be monitored as required by the evaluation in 12.2.1.

12.4.2 Gas Detection.

12.4.2.1 Continuously monitored low-temperature sensors or flammable gas detection systems shall sound an alarm at the plant site and at a constantly attended location if the plant site is not attended continuously.

12.4.2.2 Flammable gas detection systems shall activate an audible and a visual alarm at not more than 25 percent of the lower flammable limit of the gas or vapor being monitored.

12.4.3 Fire Detectors.

12.4.3.1 Fire detectors shall activate an alarm at the plant site and at a constantly attended location if the plant site is not attended continuously.

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12.4.3.2 If so determined by an evaluation in accordance with 12.2.1, fire detectors shall be permitted to activate portions of the ESD system.

12.4.4* The detection systems shall be designed, installed, and maintained in accordance with *NFPA 72, National Fire Alarm and Signaling Code*.

12.5 Fire Protection Water Systems.

12.5.1 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 12.2.1 determines that the use of water is unnecessary or impractical.

12.5.2 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) for hand hose streams for at least 2 hours.

12.6 Fire Extinguishing and Other Fire Control Equipment.

12.6.1* Portable or wheeled fire extinguishers shall be recommended for gas fires by their manufacturer.

12.6.1.1 Portable or wheeled fire extinguishers shall be available at strategic locations, as determined in accordance with 12.2.1, within an LNG facility and on tank vehicles.

12.6.1.2 Portable and wheeled fire extinguishers shall conform to the requirements of NFPA 10, *Standard for Portable Fire Extinguishers*.

12.6.1.3 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.

12.6.1.4 For facility hazard areas where minimal class "A" fire hazards are present, the selection of potassium bicarbonate–based dry chemical extinguishers is recommended.

12.6.1.5 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.

12.6.2 If provided, automotive and trailer-mounted fire apparatus shall not be used for any other purpose.

12.6.3 Fire trucks shall conform to NFPA 1901, *Standard for Automotive Fire Apparatus*.

12.6.4 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).

12.7 Maintenance of Fire Protection Equipment. Facility operators shall prepare and implement a maintenance program for all plant fire protection equipment.

12.8 Personnel Safety.

12.8.1* Protective clothing that will provide protection against the effects of exposure to LNG shall be available and readily accessible at the facility.

12.8.2 Employees who are involved in emergency response activities shall be equipped with protective clothing and equipment and trained in accordance with NFPA 600, *Standard on Industrial Fire Brigades*.

12.8.3* Written practices and procedures shall be developed to protect employees from the hazards of entry into confined or hazardous spaces.

12.8.4* At least three portable flammable gas indicators shall be readily available.

12.9 Security.

12.9.1 Security Assessment.

12.9.1.1 A security assessment covering hazards, threats, vulnerabilities, and consequences shall be prepared for the LNG facility.

12.9.1.2 The security assessment shall be available to the authority having jurisdiction on a nonpublic basis.

12.9.2 The facility operator shall provide a security system with controlled access that is designed to prevent entry by unauthorized persons.

12.9.3 At LNG facilities, there shall be a protective enclosure including a peripheral fence, building wall, or natural barrier enclosing major facility components, such as the following:

(1) LNG storage containers
(2) Flammable refrigerant storage tanks
(3) Flammable liquid storage tanks
(4) Other hazardous materials storage areas
(5) Outdoor process equipment areas
(6) Buildings housing process or control equipment
(7) Onshore loading and unloading facilities

12.9.3.1 The LNG facility shall be enclosed either by a single continuous enclosure or by multiple independent enclosures.

12.9.3.2 Where the enclosed area exceeds 1250 ft^2 (116 m^2), at least two exit gates or doors shall be provided.

12.9.4 LNG facilities shall be illuminated in the vicinity of protective enclosures and in other areas as necessary to promote security of the facility.

Chapter 13 Requirements for Stationary Applications Using ASME Containers

13.1 Scope.

13.1.1 This chapter provides requirements for the installation, design, fabrication, and siting of LNG facilities using containers of 100,000 U.S. gal (379 m^3) water capacity and less, constructed in accordance with the ASME *Boiler and Pressure Vessel Code*.

13.1.2 The maximum aggregate storage capacity of the facility shall be 280,000 U.S. gal (1060 m^3) water capacity.

13.2 General Requirements.

13.2.1 Site preparation shall include provisions for retention of spilled LNG within the limits of plant property and for surface water drainage.

13.2.2 All-weather accessibility to the site for emergency services equipment shall be provided.

13.2.3 Storage and transfer equipment at unattended facilities shall be secured to prevent tampering.

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13.2.4 Operating instructions identifying the location and operation of emergency controls shall be posted conspicuously in the facility area.

13.2.5 Designers, fabricators, and constructors of LNG facility systems and equipment shall be competent in their respective fields.

13.2.6 Supervision shall be provided for the fabrication, construction, and acceptance tests of facility components necessary to ensure that facilities are in compliance with this standard.

13.2.7 Facilities transferring LNG during the night shall have lighting at the transfer area.

13.2.8 The maximum allowable working pressure shall be specified for all pressure-containing components.

13.3 Containers.

13.3.1 All piping that is a part of an 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 B 31.3, *Process Piping*.

13.3.2 Compliance with 13.3.1 shall be stated on or appended to the ASME *Boiler and Pressure Vessel Code*, Appendix W, Form U-1, "Manufacturer's Data Report for Pressure Vessels."

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

13.3.4 Bellows shall not be permitted within the insulation space.

13.3.5 Containers shall be double-walled, with the inner tank holding LNG surrounded by insulation contained within the outer tank.

13.3.6 The inner tank shall be of welded construction and in accordance with the ASME *Boiler and Pressure Vessel Code*, Section VIII, and shall be ASME-stamped and registered with the National Board of Boiler and Pressure Vessel Inspectors or another agency that registers pressure vessels.

13.3.7 The inner tank supports shall be designed for shipping, seismic, and operating loads.

13.3.8 The support system to accommodate the expansion and contraction of the inner tank shall be designed so that the resulting stresses imparted to the inner and outer tanks are within allowable limits.

13.3.9 The outer tank shall be of welded construction using any of the following materials:

(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 Table 1A of the ASME *Boiler and Pressure Vessel Code*, Section II, Part D
(2) Materials with a melting point below 2000°F (1093°C) where the container is buried or mounded

13.3.10 Where vacuum insulation is used, the outer tank shall be designed by either of the following:

(1) The ASME *Boiler and Pressure Vessel Code*, Section VIII, Parts UG-28, UG-29, UG-30, and UG-33, 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*

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

13.3.12 The outer tank shall be equipped with a relief device or other device to release internal pressure.

13.3.12.1 The discharge area shall be at least 0.00024 $in.^2/lb$ ($0.34\ mm^2/kg$) of the water capacity of the inner tank, but the area shall not exceed 300 $in.^2$ ($0.2\ m^2$).

13.3.12.2 The relief device shall function at a pressure not exceeding the internal design pressure of the outer tank, the external design pressure of the inner tank, or 25 psi (172 kPa), whichever is least.

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

13.3.14 Seismic Design.

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

$$V = Z_c \times W$$

For vertical force:

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

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 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

13.3.14.2 Usage.

(A) The method of design described in 13.3.14.1 shall be used only where the natural period, *T*, of the shop-built container and its supporting system is less than 0.06 second.

(B) If the natural period *T* is 0.06 or greater, 7.4.4.1 and 7.4.4.2 shall apply.

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

13.3.14.4 The requirements of Section 13.3 shall apply to ASME containers built prior to July 1, 1996, when reinstalled.

13.3.15 Each container shall be identified by the attachment of a nameplate(s) in an accessible location marked with the information required by the ASME *Boiler and Pressure Vessel Code* and the following:

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(1) Builder's name and date container was built
(2) Nominal liquid capacity
(3) Design pressure at the top of the container
(4) Maximum permitted liquid density
(5) Maximum filling level
(6) Minimum design temperature

13.3.16 All penetrations of storage containers shall be marked with the function of the penetration. Penetration markings shall be visible if frosting occurs.

13.4 Container Filling. 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 the inlet of the relief device(s) from becoming covered with liquid when the pressure in the container reaches the set pressure of the relieving device(s) under all conditions.

13.5 Container Foundations and Supports.

13.5.1 LNG container foundations shall be designed and constructed in accordance with *NFPA 5000, Building Construction and Safety Code*.

13.5.2 The design of saddles and legs shall include shipping loads, erection loads, wind loads, and thermal loads.

13.5.3 Foundations and supports shall have a fire resistance rating of not less than 2 hours and shall be resistant to dislodgment by hose streams.

13.5.4 LNG storage containers installed in an area subject to flooding shall be secured to prevent the release of LNG or flotation of the container in the event of a flood.

13.6 Container Installation.

13.6.1 LNG containers of 1000 gal (3.8 m^3) and smaller shall be located as follows:

(1) 125 gal (0.47 m^3) or less, 0 ft (0 m) from property lines that can be built upon
(2) Larger than 125 gal (0.47 m^3) to 1000 gal (3.8 m^3), 10 ft (3.0 m) from property lines that can be built upon

13.6.2 Minimum Distance.

13.6.2.1 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 13.6.2.1 for each of the following:

(1) Nearest offsite building
(2) The property line that can be built upon
(3) Spacing between containers

13.6.2.2 The distance from the edge of an impoundment or container drainage system to buildings or walls of concrete or masonry construction shall be reduced from the distance in Table 13.6.2.1 with the approval of the authority having jurisdiction with a minimum of 10 ft (3 m).

13.6.3 Underground LNG tanks shall be installed in accordance with Table 13.6.3.

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

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

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

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

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

13.6.9 The point where connections are made for product transfer shall be located not less than 25 ft (7.6 m) from the following:

(1) The nearest important building not associated with the LNG facility
(2) The line of adjoining property that can be built upon

13.6.10 LNG tanks and their associated equipment shall not be located where exposed to failure of overhead electric power lines operating at over 600 volts.

13.7 Automatic Product Retention Valves.

13.7.1 All liquid and vapor connections, except relief valve and instrument connections, shall be equipped with automatic fail-safe product retention valves.

13.7.2* 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

13.7.3 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.

13.7.4 Appurtenances shall be installed as close to the container as practical so that a break resulting from external strain shall occur on the piping side of the appurtenance while maintaining intact the valve and piping on the container side of the appurtenance.

13.8 LNG Spill Containment.

13.8.1 Impoundment (dikes), topography, or other methods to direct LNG spills to a safe location and to prevent LNG spills from entering water drains, sewers, waterways, or any closed-top channel shall be used.

13.8.2 Flammable liquid storage tanks shall not be located within an LNG container impoundment area.

13.8.3 Impounding areas serving aboveground and mounded LNG containers shall have a minimum volumetric holding capacity, including any useful holding capacity of the drainage area and with allowance made for the displacement of snow accumulation, other containers, and equipment, in accordance with the following:

(1) Where containers in the dike area are constructed or protected to prevent failure from spilled LNG and fire in the dike, the minimum holding of the dike shall be the volume of the largest container in the dike.
(2) Where containers in the dike area are not constructed or protected to prevent failure from spilled LNG and fire in the dike, the minimum holding of the dike shall be equal to the total volume of the containers in the dike area.

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Table 13.6.2.1 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	m^3	ft	m	ft	m
1000–2000	3.8–7.6	15	4.6	5	1.5
2001–18,000	≥7.6–56.8	25	7.6	5	1.5
18,001–30,000	≥56.8–114	50	15	5	1.5
30,001–70,000	≥114–265	75	23	¼ of the sum of the diameters of adjacent containers [5 ft (1.5 m) minimum]	
>70,000	>265	0.7 times the container diameter [100 ft (30 m) minimum]			

Table 13.6.3 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	m^3	ft	m	ft	m
<18,000	<15.8	15	4.6	15	4.6
18,000–30,000	15.8–114	25	7.6	15	4.6
30,001–100,000	>114	40	12.2	15	4.6

13.8.4 Impounding areas shall be designed or equipped to clear rain or other water.

13.8.4.1 Where automatically controlled sump pumps are used, they shall be equipped with an automatic cutoff device that prevents their operation when exposed to LNG temperatures.

13.8.4.2 Piping, valves, and fittings whose failure could allow liquid to escape from the impounding area shall be designed to withstand continuous exposure to the temperature of LNG.

13.8.4.3 Where gravity drainage is employed for water removal, the gravity draining system shall be designed to prevent the escape of LNG by way of the drainage system.

13.9 Inspection.

13.9.1 Prior to initial operation, containers shall be inspected to ensure compliance with the engineering design and material, fabrication, assembly, and test provisions of this chapter.

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

13.10 Shop Testing of LNG Containers.

13.10.1 The outer tank shall be leak tested.

13.10.2 Piping between the inner container and the first connection outside the outer container shall be tested in accordance with ASME B 31.3.

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

13.12 Field Testing of LNG Containers.

13.12.1 Containers and associated piping shall be leak tested prior to filling with LNG.

13.12.2 After acceptance tests are completed, there shall be no field welding on the LNG containers.

13.13 Welding on Containers.

13.13.1 Field welding shall be done only on saddle plates or brackets provided for the purpose.

13.13.2 Where repairs or modifications incorporating welding are required, they shall comply with the code or standard under which the container was fabricated.

13.13.3 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 ele-

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ment affected and is necessary to demonstrate the adequacy of the repair or modification.

13.14 Piping.

13.14.1 All piping that is part of an LNG container and the facility associated with the container for handling cryogenic liquid or flammable fluid shall be in accordance with ASME B 31.3, and the following:

(1) Type F piping, spiral welded piping, and furnace butt-welded steel products shall not be permitted.
(2) All welding or brazing shall be performed by personnel qualified to the requirements of the ASME B 31.3, subsection 328.2, Welding Qualifications, and ASME *Boiler and Pressure Vessel Code*, Section IX, as applicable.
(3) Oxygen–fuel gas welding shall not be permitted.
(4) Brazing filler metal shall have a melting point exceeding 1000°F (538°C).
(5) All piping and tubing shall be austenitic stainless steel for all services below –20°F (–29°C).
(6) All piping and piping components, except gaskets, seals, and packing, shall have a minimum melting point of 1500°F (816°C).
(7) Aluminum shall be used only downstream of a product retention valve in vaporizer service.
(8) Compression-type couplings used where they can be subjected to temperatures below –20°F (–29°C) shall meet the requirements of ASME B 31.3, Section 315.
(9) Stab-in branch connections shall not be permitted.
(10) Extended bonnet valves shall be used for all cryogenic liquid service, and they shall be installed so that the bonnet is at an angle of not more than 45 degrees from the upright vertical position.

13.14.2* The level of examination of piping shall be specified.

13.15 Container Instrumentation.

13.15.1 General. Instrumentation for LNG facilities shall be designed so that, in the event of power or instrument air failure, the system will go into a fail-safe condition that can be maintained until the operators can take action to reactivate or secure the system.

13.15.2 Level Gauging. LNG containers shall be equipped with liquid level devices as follows:

(1) Containers of 1000 gal (3.8 m^3) or larger shall be equipped with two independent liquid level devices.
(2) Containers smaller than 1000 gal (3.8 m^3) shall be equipped with either a fixed length dip tube or other level devices.
(3) Containers of 1000 gal (3.8 m^3) or larger shall have one liquid level device that provides a continuous level indication ranging from full to empty and that is maintainable or replaceable without taking the container out of service.

13.15.3 Pressure Gauging and Control.

13.15.3.1 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.

13.15.3.2 Vacuum-jacketed equipment shall be equipped with instruments or connections for checking the pressure in the annular space.

13.15.3.3 Safety relief valves shall be sized to include conditions resulting from operational upset, vapor displacement, and flash vaporization resulting from pump recirculation and fire.

13.15.4 Pressure relief valves shall communicate directly with the atmosphere.

13.15.5 Pressure relief valves shall be sized in accordance with 7.3.6.5 or with CGA S-1.3, *Pressure Relief Device Standards — Part 3 — Compressed Gas Storage Containers*.

13.15.6 Inner container pressure relief valves shall have a manual full-opening stop valve to isolate it from the container.

13.15.6.1 The stop valve shall be lockable or sealable in the fully open position.

13.15.6.2 The installation of pressure relief valves shall allow each relief valve to be isolated individually for testing or maintenance while maintaining the full relief capacities determined in 7.3.6.5.

13.15.6.3 Where only one pressure relief valve is required, either a full-port opening three-way valve used under the pressure relief valve and its required spare or individual valves beneath each pressure relief valve shall be installed.

13.15.7 Stop valves under individual safety relief valves shall be locked or sealed when opened and shall not be opened or closed except by an authorized person.

13.15.8 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, if arranged to discharge directly into the atmosphere, shall discharge vertically upward.

13.16 Fire Protection and Safety. The requirements of Sections 12.1 and 12.2; 12.3.1; 12.4.1; Sections 12.5, 12.6, and 12.7; 12.8.2; and 12.8.3 shall apply.

13.17 Gas Detection. An operating portable flammable gas indicator shall be readily available.

13.18 Operations and Maintenance. Each facility shall have written operating, maintenance, and training procedures based on experience, knowledge of similar facilities, and conditions under which the facility will be operated.

13.18.1 Basic Operations Requirements. Each facility shall meet the following requirements:

(1) Have written procedures covering operation, maintenance, and training
(2) Keep up-to-date drawings of plant equipment, showing all revisions made after installation
(3) Revise the plans and procedures as operating conditions or facility equipment require
(4) Establish a written emergency plan
(5) Establish liaison with appropriate local authorities such as police, fire department, or municipal works and inform them of the emergency plans and their role in emergency situations
(6) Analyze and document all safety-related malfunctions and incidents for the purpose of determining their causes and preventing the possibility of recurrence

13.18.2 Operating Procedures Manual.

13.18.2.1 Each facility shall have a written manual of operating procedures, including the following:

(1) Conducting a proper startup and shutdown of all components of the facility, including those for an initial startup of the LNG facility that will ensure that all components will operate satisfactorily
(2) Purging and inerting components

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(3) Cooling down components
(4) Ensuring that each control system is properly adjusted to operate within its design limits
(5) Maintaining the vaporization rate, temperature, and pressure so that the resultant gas is within the design tolerance of the vaporizer and the downstream piping
(6) Determining the existence of any abnormal conditions and indicating the response to those conditions
(7) Ensuring the safety of personnel and property while repairs are carried out, whether or not equipment is in operation
(8) Ensuring the safe transfer of hazardous fluids
(9) Ensuring security at the LNG plant
(10) Monitoring operation by watching or listening for warning alarms from an attended control center and by conducting inspections on a planned, periodic basis
(11) Monitoring the foundation heating system weekly

13.18.2.2 The manual shall be accessible to operating and maintenance personnel.

13.18.2.3 The manual shall be updated when changes in equipment or procedures are made.

13.18.2.4 The operations manual shall contain procedures to ensure the following:

(1) That the cooldown of each system of components under its control and subjected to cryogenic temperatures is limited to a rate and a distribution pattern that maintain the thermal stresses within the design limits of the system during the cooldown period, having regard for the performance of expansion and contraction devices
(2) That each facility has procedures to check each cryogenic piping system under its control during and after cooldown stabilization for leaks in areas where there are flanges, valves, and seals

13.18.2.5 Each operations manual shall include purging procedures that, when implemented, minimize the presence of a combustible mixture in plant piping or equipment when a system is being placed into or taken out of operation.

13.18.2.6 The operations manual shall contain procedures for loading or unloading operations applicable to all transfers, including the following:

(1) Written procedures shall cover all transfer operations and shall cover emergency as well as normal operating procedures.
(2) Written procedures shall be kept up-to-date and available to all personnel engaged in transfer operations.
(3) Prior to transfer, gauge readings shall be obtained or inventory established to ensure that the receiving vessel cannot be overfilled.
(4) Levels of the receiving vessel shall be checked during transfer operations.
(5) The transfer system shall be checked prior to use to ensure that valves are in the correct position.
(6) Pressure and temperature conditions shall be observed during the transfer operation.

13.18.2.7 Each operations manual for a facility that transfers LNG from or to a cargo tank vehicle or a tank car shall contain procedures for loading or unloading tank cars or tank vehicles, including the following:

(1) While tank car or tank vehicle 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.
(2) Prior to connecting a tank car, the car shall be checked and the brakes set, the derailer or switch properly positioned, and warning signs or lights placed as required.
(3) The warning signs or lights shall not be removed or reset until the transfer is completed and the car disconnected.
(4) Unless required for transfer operations, truck vehicle engines shall be shut off.
(5) Brakes shall be set and wheels checked prior to connecting for unloading or loading.
(6) The engine shall not be started until the truck vehicle has been disconnected and any released vapors have dissipated.
(7) Prior to loading LNG into a tank car or tank vehicle that is not in exclusive LNG service, a test shall be made to determine the oxygen content in the container.
(8) If a tank car or tank vehicle in exclusive LNG service does not contain a positive pressure, it shall be tested for oxygen content.
(9) If the oxygen content in either case exceeds 2 percent by volume, the container shall not be loaded until it has been purged to below 2 percent oxygen by volume.

13.18.3 Emergency Procedures.

13.18.3.1 Each facility shall have a written manual of emergency procedures that shall include the types of emergencies that are anticipated from an operating malfunction, structural collapse of part of the facility, personnel error, forces of nature, and activities carried on adjacent to the facility, including the following:

(1) Procedures for responding to controllable emergencies, including notification of personnel and the use of equipment that is appropriate for handling of the emergency and the shutdown or isolation of various portions of the equipment and other applicable steps to ensure that the escape of gas or liquid is promptly cut off or reduced as much as possible
(2) Procedures for recognizing an uncontrollable emergency and for taking action to ensure that harm to the personnel at the facility and to the public is minimized
(3) Procedures for the prompt notification of the emergency to the appropriate local officials, including the possible need to evacuate persons from the vicinity of the facility
(4) 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

13.18.3.2* When local officials are contacted in an emergency, procedures shall include the method of notification of the following:

(1) The quantity and location of fire equipment throughout the facility
(2) Potential hazards at the facility
(3) Communication and emergency control capabilities of the facility
(4) The status of each emergency

13.18.4 Maintenance. Each facility shall have written maintenance procedures based on experience, knowledge of similar facilities, and conditions under which the facilities will be maintained.

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13.18.4.1 Each facility operator shall carry out periodic inspection, tests, or both on a schedule that is included in the maintenance plan on identified components and its support system in service in the facility, to verify that the components are maintained in accordance with the equipment manufacturer's recommendations and the following:

(1) The support system or foundation of each component shall be inspected at least annually to ensure that the support system or foundation is sound.
(2) Each emergency power source at the facility shall be tested monthly to ensure that it is operational and tested annually to ensure that it is capable of performing at its intended operating capacity.
(3) When a safety device serving a single component is taken out of service for maintenance or repair, the component shall also be taken out of service, except where the safety function is provided by an alternative means.
(4) 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 equivalent, shall be attached to the controls of the component, or the component shall be locked out.
(5) Stop valves for isolating pressure or vacuum-relief valves shall be locked or sealed open and shall be operated only by an authorized person.
(6) No more than one pressure or vacuum relief valve stop valve shall be closed at one time on an LNG container.

13.18.4.2 Maintenance Manual.

(A) Each facility operator shall prepare a written manual that sets out an inspection and maintenance program for identified components that are used in the facility.

(B) The maintenance manual for facility components shall include the following:

(1) The manner of carrying out and the frequency of the inspections and tests referred to in 13.18.4.1
(2) A description of any other action in addition to those referred to in 13.18.4.2(B)(1) that is necessary to maintain the 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 facility

(C) Each facility operator shall conduct the facility's maintenance program in accordance with the written manual for facility components.

13.18.4.3 Facility Maintenance.

(A) Each facility operator shall keep the grounds of the facility free from rubbish, debris, and other materials that could present a fire hazard.

(B) Each facility operator shall ensure that the components of the facility are kept free from ice and other foreign materials that could impede their performance.

(C) Each facility operator shall maintain the grassed area of its facility so that it does not create a fire hazard.

(D) All fire-control access routes within an LNG facility shall be maintained and kept unobstructed in all weather conditions.

13.18.4.4 Repairs that are carried out on components of a 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 the components will operate in a safe manner
(3) That the safety of personnel and property during a repair activity is maintained

13.18.4.5 Each facility operator shall ensure that a control system that is out of service for 30 days or more is tested prior to its return to service, to ensure that it is in proper working order.

(A) Each facility operator shall ensure that the inspections and tests in this section are carried out at the intervals specified.

(B) Control systems that are used seasonally shall be inspected and tested before use each season.

(C) Control systems that are used as part of the fire protection system at the facility shall be inspected and tested in accordance with the applicable fire codes and standards and conform to the following criteria:

(1) Monitoring equipment shall be maintained in accordance with *NFPA 72, National Fire Alarm and Signaling Code*, and NFPA 1221, *Standard for the Installation, Maintenance, and Use of Emergency Services Communications Systems*.
(2) Fire protection water systems, if required, shall be maintained in accordance with NFPA 13, *Standard for the Installation of Sprinkler Systems*; NFPA 14, *Standard for the Installation of Standpipe and Hose Systems*; NFPA 15, *Standard for Water Spray Fixed Systems for Fire Protection*; NFPA 20, *Standard for the Installation of Stationary Pumps for Fire Protection*; NFPA 22, *Standard for Water Tanks for Private Fire Protection*; NFPA 24, *Standard for the Installation of Private Fire Service Mains and Their Appurtenances*; and NFPA 25, *Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems*.
(3) Portable or wheeled fire extinguishers suitable for gas fires, preferably of the dry-chemical type, shall be available at strategic locations, as determined in accordance with Chapter 12, within an LNG facility and on tank vehicles, and shall be maintained in accordance with NFPA 10, *Standard for Portable Fire Extinguishers*.
(4) Fixed fire extinguishers and other fire-control systems that are installed shall be maintained in accordance with NFPA 11, *Standard for Low-, Medium-, and High-Expansion Foam*; NFPA 12, *Standard on Carbon Dioxide Extinguishing Systems*; NFPA 12A, *Standard on Halon 1301 Fire Extinguishing Systems*; NFPA 16, *Standard for the Installation of Foam-Water Sprinkler and Foam-Water Spray Systems*; and NFPA 17, *Standard for Dry Chemical Extinguishing Systems*.

(D) 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.

(E) The external surfaces of LNG storage tanks shall be inspected and tested as set out in the maintenance manual for the following:

(1) Inner tank leakage
(2) Soundness of insulation
(3) Tank foundation heating to ensure that the structural integrity or safety of the tanks is not affected

(F) LNG storage plants 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 plant is intact.

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13.18.4.6 Maintenance Records.

(A) Each facility operator shall maintain a record of the date and the type of each maintenance activity performed.

(B) Maintenance records shall be retained for a period of not less than 5 years.

13.18.5 Training.

13.18.5.1 Every facility operator shall develop, implement, and maintain a written training plan to instruct appropriate facility personnel with respect to the following:

(1) Carrying out the emergency procedures that relate to their duties at the facility as set out in the procedure manual referred to in 13.18.3, and providing first aid
(2) For permanent maintenance, operating, and supervisory personnel the following:
   (a) The basic operations carried out at the facility
   (b) The characteristics and potential hazards of LNG and other hazardous fluids involved in operating and maintaining the facility, including the serious danger from frostbite that can result from contact with LNG or cold refrigerants
   (c) The methods of carrying out their duties of maintaining and operating the facility as set out in the manual of operating and maintenance procedures referred to in 13.18.2 and 13.18.4
   (d) The LNG transfer procedures required in 13.18.2.6 and 13.18.2.7
   (e) Fire prevention, including familiarization with the fire control plan of the facility, fire fighting, the potential causes of fire in a facility, and the types, sizes, and likely consequences of a fire at a facility
   (f) Recognition of situations in which it is necessary to obtain assistance in order to maintain the security of the facility

13.18.5.2 Each facility operator shall develop, implement, and maintain a written plan to keep the personnel at the facility up to date on the function of the systems, fire prevention, and security at the facility.

13.18.5.3 The plans required in 13.18.5.2 shall provide for training sessions to update personnel at intervals that do not exceed 2 years.

13.18.5.4 Employee Records.

(A) Every facility operator shall maintain a record for each applicable employee of the facility that sets out the training given to the employee under 13.18.5.

(B) The employee records shall be maintained for at least 2 years after the date that the employee ceases to be employed at the facility.

13.18.5.5 Each facility operator shall ensure the following:

(1) That facility personnel receive applicable training referred to in 13.18.5
(2) That facility personnel have experience related to their assigned duties

13.18.5.6 Any person who has not completed the training or who does not have the experience set out in 13.18.5 shall be under the control of trained personnel.

Chapter 14 Operating, Maintenance, and Personnel Training

14.1* Scope. This chapter contains basic requirements and minimum standards for the safety aspects of the operation and maintenance of LNG plants.

14.2 General Requirements.

14.2.1 Each operating company shall develop documented operating, maintenance, and training procedures, based on experience and conditions under which the LNG plant is operated.

14.2.2 The operating company shall meet the following requirements:

(1) Document procedures covering operation, maintenance, and training
(2) Maintain up-to-date drawings, charts, and records of plant equipment
(3) Revise plans and procedures when operating conditions or plant equipment are revised
(4) Ensure cooldown of components in accordance with 14.3.5.
(5) Establish a documented emergency plan
(6) Establish liaison with local authorities such as police, fire department, or municipal works to inform them of the emergency plans and their role in emergency situations
(7)*Analyze and document all safety-related conditions for the purpose of determining their causes and preventing the possibility of recurrence

14.3 Manual of Operating Procedures.

14.3.1 All LNG plant components shall be operated in accordance with the operating procedures manual.

14.3.2 The operating procedures manual shall be accessible to all plant personnel and shall be kept readily available in the operating control center.

14.3.3 The operating manual shall be updated when there are changes in equipment or procedures.

14.3.4 The operating manual shall include procedures for the startup and shutdown of all components of the plant, including those for initial startup of the LNG plant, to ensure that all components operate satisfactorily.

14.3.5 The operating manual shall include procedures for purging components, making components inert, and cooldown of components.

14.3.5.1 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.

14.3.6 The operating manual shall include procedures to ensure that each control system is adjusted to operate the process within its design limits.

14.3.7 The operating manual of LNG plants with liquefaction facilities shall include procedures to maintain the temperatures, levels, pressures, pressure differentials, and flow rates within their design limits for the following:

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(1) Boilers
(2) Turbines and other prime movers
(3) Pumps, compressors, and expanders
(4) Purification and regeneration equipment
(5) Equipment in cold boxes

14.3.8 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 plant
(3) The safe transfer of LNG and hazardous fluids, including prevention of overfilling of containers
(4) Security

14.3.9 The operations manual shall include procedures for monitoring operations.

14.3.10 Written procedures shall be available to cover all transfer operations and shall cover emergency as well as normal operating procedures.

14.3.11 Written procedures shall be kept up to date and available to all personnel engaged in transfer operations.

14.4 Emergency Procedures.

14.4.1 Each operations manual shall contain emergency procedures.

14.4.2 The emergency procedures shall include, at a minimum, emergencies that are anticipated from an operating malfunction, structural collapse of part of the LNG plant, personnel error, forces of nature, and activities carried on adjacent to the plant.

14.4.3 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

14.4.4 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

14.4.5 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

14.4.6 Emergency procedures shall include procedures for dealing with unignited gas releases.

14.4.7 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

14.5 Monitoring Operations.

14.5.1* Control Center. Operations monitoring shall be carried out by an attended control center that watches or listens for warning alarms and by inspections conducted at least at the intervals set out in the written operating procedures referred to in Section 14.3 and, at a minimum, on a weekly basis.

14.5.2 LNG Tank Foundation.

14.5.2.1 Where the bottom of the outer tank is in contact with the soil, the heating system shall be monitored at least once a week to ensure that the 32°F (0°C) isotherm is not penetrating the soil.

14.5.2.2 Any settlement in excess of that anticipated in the design shall be investigated, and corrective action taken as required.

14.5.3 Cooldown. Each cryogenic piping system that is under the operating company's control shall be checked during and after cooldown stabilization for leaks in areas where there are flanges, valves, and seals.

14.5.4 Depressurizing. The discharge from depressurizing shall be directed to minimize exposure to personnel or equipment.

14.5.5 Purging.

14.5.5.1 The temperature of the purge gas or liquid shall be within the design temperature limits of the container or other equipment.

14.5.5.2 The pressure of the container or other equipment during purging shall be within the design pressure limits of the container.

14.5.5.3 Piping systems shall be purged of air or gas in a safe manner. *(See Section 9.8.)*

14.5.5.4* Container Purging Procedures.

14.5.5.4.1 Taking an LNG container out of service shall not be regarded as a normal operation.

14.5.5.4.2 The activities of 14.5.5 shall require the preparation of detailed procedures.

14.5.5.4.3 Only experienced, trained personnel shall purge LNG containers.

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14.5.5.4.4 Before an LNG container is put into service, the air shall be displaced by an inert gas, by following a written purging procedure.

14.5.5.4.5* Before a container is taken out of service, the natural gas in the container shall be purged from the container with an inert gas, using a written purging procedure.

14.5.5.5 During purging operations, the oxygen content of the container or other equipment shall be monitored by the use of an oxygen analyzer.

14.6 Transfer of LNG and Flammables.

14.6.1 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.

14.6.2 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.

14.6.3 Where a mixing nozzle or agitation system is provided, it shall be designed to prevent rollover.

14.6.4 At least one qualified person shall be in constant attendance while a transfer is in progress.

14.6.5 Sources of ignition shall not be permitted in loading or unloading areas while transfer is in progress.

14.6.6 Loading and Unloading Tank Vehicle and Tank Car.

14.6.6.1 Sources of ignition shall not be allowed in loading or unloading areas while transfer is in progress.

14.6.6.2 Loading and unloading areas shall be posted with signs that read "No Smoking."

14.6.6.3 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.

14.6.6.4 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.

14.6.6.5 The transfer system shall be checked prior to use to ensure that valves are in the correct position.

14.6.6.6 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.

14.6.6.7 Pressure and temperature conditions shall be monitored during the transfer operation.

14.6.6.8 While tank car or tank vehicle 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.

14.6.6.8.1 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.

14.6.6.8.2 The warning signs or lights shall not be removed or reset until the transfer is completed and the car disconnected.

14.6.6.8.3 Truck vehicle engines shall be shut off if they are not required for transfer operations.

14.6.6.8.4 Brakes shall be set and wheels chocked prior to connection for unloading or loading.

14.6.6.8.5 The engine shall not be started until the truck vehicle has been disconnected and any released vapors have dissipated.

14.6.6.9 Oxygen Content.

(A) Before LNG is loaded into a tank car or tank vehicle that is not in exclusive LNG service, a test shall be made to determine the oxygen content in the container.

(B) 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.

(C) If a tank car or tank vehicle in exclusive LNG service does not contain a positive pressure, it shall be tested for oxygen content.

14.6.6.10 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.

14.6.6.11 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.

14.6.6.12 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.

14.6.7 Marine Shipping and Receiving.

14.6.7.1 Vessel Arrival.

14.6.7.1.1 The requirements of 14.4.7 shall be communicated to the vessel operator to facilitate safe vessel berthing and unberthing.

14.6.7.1.2 Warning signs or barricades shall be used to indicate that transfer operations are in progress.

14.6.7.1.3 A vessel-specific mooring plan utilizing the criteria developed in 11.5.1 shall be developed for each ship calling at the waterfront facility.

14.6.7.1.4 The vessel shall be moored in a safe and effective manner.

14.6.7.1.5 The terminal operator shall certify in writing that the provisions of 14.9.5.1 and 14.9.5.3 are met.

14.6.7.1.6 This certification shall be available for inspection at the waterfront facility that handles LNG.

14.6.7.2 Prior to Transfer.

14.6.7.2.1 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

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(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

14.6.7.2.2 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.

14.6.7.2.3 Following the inspection described in 14.6.7.2.2, 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.

14.6.7.2.4 After the pretransfer inspection required by 14.6.7.2.1 has been satisfactorily completed, there shall be no transfer of LNG until a declaration of inspection that demonstrates full compliance with 14.6.7.2.2 is executed and signed.

(A) 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.

(B) 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

14.6.7.2.5 The communication system required in 11.9.3 shall be continuously monitored both aboard ship and at the terminal.

14.6.7.3 Marine Connections.

14.6.7.3.1 When loading arms are connected for marine loading or unloading operations, all bolt holes in a flange shall be utilized for the connection.

14.6.7.3.2 Blind flanges shall be utilized on those arms not engaged in loading or unloading operations.

14.6.7.3.3 All connections shall be leaktight and tested prior to operation.

14.6.7.3.4 Marine loading or unloading arms shall be purged prior to use and purged and completely drained upon completion of transfer.

14.6.7.3.5 Marine loading or unloading operations shall be at atmospheric pressure when the arm(s) are connected or disconnected.

14.6.7.4* Transfer Operations in Progress.

14.6.7.4.1 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.

14.6.7.4.2 Warning signs or barricades shall be used to indicate that transfer operations are in progress.

14.6.7.4.3* There shall be two independent means of egress, including emergency egress, from the ship.

14.6.7.4.4 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.

14.6.7.4.5 Sources of ignition shall not be permitted in the marine transfer area while transfer is in progress.

14.6.7.4.6 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) of the point where connections are made for LNG, and flammable fluids transfer while LNG or flammable fluids are being transferred through piping systems.

14.6.7.5 Bunkering Operations.

14.6.7.5.1 Bunkering operations shall be in accordance with any requirements established by the authority having jurisdiction over vessels or terminals.

14.6.7.5.2 During bunkering operations, the following shall apply:

(1) Personnel involved in bunkering operations shall not have simultaneous responsibility involved in the transfer of LNG.
(2) No vessels shall be moored alongside the LNG vessel without the permission of the authority having jurisdiction.

14.7 Maintenance Manual.

14.7.1 Each operating company shall have a documented plan that sets out inspection and maintenance program requirements for each component used in its LNG plant that is identified as requiring inspection and maintenance.

14.7.2 Each maintenance program shall be conducted in accordance with its documented plan for LNG plant components identified in the plan as requiring inspection and maintenance.

14.7.3 Each operating company shall perform the periodic inspections, tests, or both, on a schedule that is included in

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the maintenance plan on identified components and its support system identified as requiring inspection and maintenance that is in service in its LNG plant.

14.7.4 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.

14.7.5 The maintenance manual shall include the following for LNG plant 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 14.7.5, that is necessary to maintain the LNG plant 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

14.7.6 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.

14.7.7 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.

14.8 Maintenance.

14.8.1 Each operating company shall ensure that components in its LNG plant that could accumulate combustible mixtures are purged after being taken out of service and before being returned to service.

14.8.2 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.

14.8.3 Foundation.

14.8.3.1 The support system or foundation of each component shall be inspected at least annually.

14.8.3.2 If the foundation is found to be incapable of supporting the component, it shall be repaired.

14.8.4 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.

14.8.5 Insulation systems for impounding surfaces shall be inspected annually.

14.8.6 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.

14.8.7 Marine loading or unloading operations shall be periodically tested as required by the authority having jurisdiction.

14.8.8 Repairs. Repairs that are carried out on components of an LNG plant 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

14.8.9 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 or ice is avoided or controlled to maintain the operational safety of each LNG plant 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

14.8.10 Control Systems, Inspection, and Testing.

14.8.10.1 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.

14.8.10.2 Each operating company shall ensure that the inspections and tests in this section are carried out at the intervals specified.

14.8.10.3 Control systems that are used seasonally shall be inspected and tested before use each season.

14.8.10.4 Control systems that are used as part of the fire protection system at the LNG plant 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, National Fire Alarm and Signaling Code*, and NFPA 1221, *Standard for the Installation, Maintenance, and Use of Emergency Services Communications Systems.*
(2) Fire protection water systems shall be maintained in accordance with NFPA 13, *Standard for the Installation of Sprinkler Systems*; NFPA 14, *Standard for the Installation of Standpipe and Hose Systems*; NFPA 15, *Standard for Water Spray Fixed Systems for Fire Protection*; NFPA 20, *Standard for the Installation of Stationary Pumps for Fire Protection*; NFPA 22, *Standard for Water Tanks for Private Fire Protection*; NFPA 24, *Standard for the Installation of Private Fire Service Mains and Their Appurtenances*; and NFPA 25, *Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems.*
(3) *Portable or wheeled fire extinguishers suitable for gas fires shall be available at strategic locations, as determined in accordance with Chapter 12, within an LNG facility and on tank vehicles and shall be maintained in accordance with NFPA 10, *Standard for Portable Fire Extinguishers.*
(4) Fixed fire extinguishers and other fire control equipment shall be maintained in accordance with NFPA 11, *Standard for Low-, Medium-, and High-Expansion Foam*; NFPA 12, *Standard on Carbon Dioxide Extinguishing Systems*; NFPA 12A, *Standard on Halon 1301 Fire Extinguishing Systems*; NFPA 16, *Standard for the Installation of Foam-Water Sprinkler and Foam-Water Spray Systems*; NFPA 17, *Standard for Dry Chemical Extinguishing Systems*; and NFPA 2001, *Standard on Clean Agent Fire Extinguishing Systems.*

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14.8.10.5 Control systems, other than those referred to in 14.8.10.3 and 14.8.10.4, shall be inspected and tested once each calendar year at intervals that do not exceed 15 months.

14.8.10.6 Stationary LNG tank 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.

14.8.10.7 All other relief valves protecting hazardous fluid components shall be randomly inspected and set-point tested at intervals not exceeding 5 years plus 3 months.

14.8.10.8 Stop valves for isolating pressure or vacuum-relief valves shall be locked or sealed open.

14.8.10.9 Stop valves shall not be operated except by an authorized person.

14.8.10.10 An LNG container shall have no more than one stop valve closed at one time.

14.8.10.11 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.

14.8.11 LNG Storage Tanks. The external surfaces of LNG storage tanks shall be inspected and tested as set out in the maintenance manual for the following:

(1) Inner tank leakage
(2) Soundness of insulation
(3) Tank foundation heating, to ensure that the structural integrity or safety of the tanks is not affected

14.8.12 Meteorological and Geophysical Events.

14.8.12.1 LNG storage plants 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 plant is intact.

14.8.12.2 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.

14.8.13 Corrosion Control.

14.8.13.1 Each operating company shall ensure the following for metallic components of its LNG plant that could be adversely affected with respect to integrity or reliability by corrosion during their service life:

(1) Protection from corrosion in accordance with Section 9.10
(2) Inspection and replacement or repair under a program of scheduled maintenance in accordance with the manual referred to under Section 14.3

14.8.13.2 Each operating company shall ensure that each component of its LNG plant that is subject to interference from an electrical current is protected so that the electrical interference is minimized.

14.8.13.3 Each impressed current power source shall be installed and maintained such that it does not interfere with any communication or control system at the LNG plant.

14.8.13.4* Every operating company shall monitor the corrosion control provided in accordance with Section 9.10.

14.8.13.5 Each buried or submerged component that is cathodically protected shall be surveyed at least once each calendar year at intervals that do not exceed 15 months, to ensure that the system meets the corrosion control requirements of applicable standards.

14.8.13.6 Each cathodic protection rectifier or impressed current system shall be inspected at least six times each calendar year at intervals that do not exceed 2½ months, to ensure that it is operating properly.

14.8.13.7 Interference bonds shall be inspected at least once each calendar year at intervals that do not exceed 15 months.

14.8.13.8 Each exposed component that is subject to corrosion from the atmosphere shall be inspected at intervals that do not exceed 3 years.

14.8.13.9 Where a component is protected from internal corrosion by a coating or inhibitors, monitoring devices designed to detect internal corrosion, such as coupons or probes, shall be located where corrosion is most likely to occur.

14.8.13.10 Internal corrosion control monitoring devices shall be checked at least two times each calendar year at intervals not exceeding 7½ months.

14.8.13.11 Components that will not be adversely affected by internal corrosion during the time that the component will be in use in the LNG plant shall be exempt from the requirements of 14.8.13.

14.8.13.12 If it is discovered by inspection or otherwise that corrosion is not being controlled at the LNG plant, necessary actions to control or monitor the corrosion shall be taken.

14.9 Personnel Training.

14.9.1 Every operating plant shall have a written training plan to instruct all LNG plant personnel.

14.9.2 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 plant
(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
(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 14.3 and 14.7
(4) LNG transfer procedures
(5) Fire prevention, including familiarization with the fire control plan of the LNG plant, fire fighting, the potential causes of fire in an LNG plant, and the types, sizes, and likely consequences of a fire at an LNG plant
(6) Recognition of situations when it would be necessary to obtain assistance in order to maintain the security of the LNG plant

14.9.3 All LNG plant personnel shall meet the following requirements:

(1) LNG plant personnel shall receive the training referred to in 14.9.2.

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(2) LNG plant personnel shall have experience related to their assigned duties.

14.9.4 Any person who has not completed the training or received experience set out in 14.9.2 shall be under the control of trained personnel.

14.9.5 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.

14.9.5.1 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 14.4.7

14.9.5.2 Time spent assisting in the transfer shall fulfill this practical training requirement.

14.9.5.3 Each person involved in the shoreside transfer operations shall have been trained in accordance with the requirements of 14.9.2 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 11
(4) Knowledge of the procedures in the terminal's operations manual and emergency manual

14.9.6 Refresher Training.

14.9.6.1 Persons who are required to receive the training in 14.9.2 or 14.9.5 shall receive refresher training in the same subjects at least once every 2 years.

14.9.6.2 Performing actual loading or unloading operations, under the observation of a qualified individual, shall fulfill the requirement for refreshing of practical training in 14.9.5.

14.10 Records.

14.10.1 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 plant, including a record of the date that a component is taken out of or placed into service.

14.10.2 Records shall be made available during business hours upon reasonable notice.

14.10.3 For the life of the LNG facility, each LNG plant 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.

14.10.4 A record of all training shall be maintained for each employee of an LNG plant, and the records shall be maintained for at least 2 years after the date that the employee ceases to be employed at the LNG plant.

Chapter 15 Performance (Risk Assessment) Based LNG Plant Siting

15.1 Scope.

15.1.1 This chapter includes the calculation of risks to persons outside the boundary of a liquefied natural gas (LNG) plant, arising from potential releases of LNG and other hazardous substances stored, transferred, or handled in the plant.

15.1.2 Where approved, the requirements of this chapter shall be complied with, in LNG facility siting and layout analysis, as an alternative to the assessments required in Chapter 5 of this code.

15.1.3 The provisions of this chapter are applicable to newly proposed facilities and existing facilities where significant modifications and improvements are proposed. Only the modifications and improvements in existing facilities shall be subject to the requirements of this chapter.

15.1.4 The chapter does not include the assessment of risks from LNG or other hazardous materials associated with the plant arising from transportation caused releases outside the plant boundary.

15.2 General Requirements.

15.2.1 LNG plants shall be designed and located in such areas as to not pose intolerable risks to the surrounding populations, installations, or property.

15.2.2* The requirements of this chapter shall be used to assess the level of risks to surrounding population to ensure that the individual risk and the societal risk do not exceed tolerable levels in accordance with Section 15.9.

15.2.3 If the plant is modified or other conditions change, the plant risk may change. Therefore, reassessments of plant risk shall be undertaken at the earlier of:

(1) When conditions change as a direct consequence of actions and significant modifications undertaken by the plant
(2) Every 5 years
(3) As required by the AHJ

15.3 Definitions. The following definitions shall apply only to usage in Chapter 15.

15.3.1* 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.

15.3.2 Event. The combination of successive outcomes of LNG, flammable fluids, flammable refrigerants or toxic material release and its subsequent hazard to persons exposed.

15.3.3* Individual Risk. The frequency, expressed in number of realizations per year, at which an individual, with continuous potential exposure, may be expected to sustain a serious or fatal injury.

15.3.4 Societal Risk. The cumulative risk exposure by all persons sustaining serious or fatal injury from an event in the LNG plant.

15.4 Risk Calculations and Basis of Assessment.

15.4.1* Both individual risks and societal risk(s) values shall be evaluated in the area around the LNG plant by using quantitative risk assessment (QRA) protocol. The generally accepted QRA protocol, specified in any one of the following publications shall be used in assessing the risks:

(1) American Institute of Chemical Engineers (AICHE) Center for Chemical Process Safety (CCPS), "Guidelines for Chemical Process Quantitative Risk Analysis," 2000

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(2) TNO, "Guidelines for Quantitative Risk Assessment, RIVM, The Purple Book," Netherlands, 2005
(3) Health and Safety Executive (HSE), "Risk Criteria for Land-use Planning in the Vicinity of Major Industrial Hazards, HMSO, HSE 1989" and "Five Steps to Risk Assessment, INDC 163, rev.1, HSE 1998," United Kingdom
(4) European Norm Standard, BSI EN 31010:2010, "Risk Management–Risk Assessment Techniques"

15.4.2 The selected QRA procedure shall be approved by the AHJ.

15.4.3 Individual risks shall be presented in the form of contours of constant individual risk values. Societal risk shall be presented in the form of a diagram of cumulative annual frequency of casualty exceedance vs. the number of exposed population subject to the casualty. (i.e., the F-N plot). Uncertainty values in the calculation of the risks (both frequency and casualty) shall be included in the diagram.

15.4.4 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.

15.5 LNG and Other Hazardous Materials Release Scenarios.

15.5.1 Catalog of Scenarios of Release. A spectrum of LNG and other hazardous material release scenarios from transfer piping, storage tank(s), vaporizer(s) and other vulnerable equipment in the plant shall be developed through the use of process hazard analyses (PHAs), HAZOP, or other thorough, systematic hazard-identification studies and scenario evaluations acceptable to the AHJ. In addition, the spectrum of releases shall include those identified as design spills in 5.3.3.7. Credible large-release scenarios that may pose risks outside the property line shall also be included along with their occurrence probabilities.

15.5.2 Release Specifications.

15.5.2.1 The release rates and durations (and when necessary the total release quantity) of LNG and other hazardous material releases shall be calculated for the scenarios of release identified in 15.5.1.

15.5.2.2 The calculation of the rate of release shall document the following:

(1) The hole or puncture sizes and upstream conditions consistent with the different storage conditions and appurtenances considered in the release scenarios identified in Section 15.5.1.
(2) The thermodynamic condition, including the pressure and temperature, of the fluid upstream of the release point

15.5.2.3 The thermal and physical characteristics of the substrate exposed to a release shall be considered in analyzing the subsequent behavior of the fluid released.

15.5.2.4 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. These behavior modes that shall be considered include, but not limited to, flashing, aerosol formation, liquid jetting, pool formation and flow, dispersion of vapors, jet fires, flash fires, explosions, fireballs, pool fires, BLEVES, and liquid water interaction effects.

Table 15.6.1 Example Component Failure Database

Component	Annual Probability of Failure
Atmospheric Cryogenic Tanks	
(1) Instantaneous failure of primary container and outer shell, release of entire contents (single containment tank)	5E-07
(2) Instantaneous failure of primary container and outer shell, release of entire contents (double containment tank)	1.25E-08
(3) Instantaneous failure of primary and secondary container, release of entire contents (full containment tank)	1E-08
Pressurized Storage	
(Containers) — instantaneous release of entire contents	5E-07
Piping — aboveground	
(1) Rupture for nominal diameter <75 mm	1E-06
(2) Rupture for 75 mm < nominal diameter < 150 mm	3E-07
(3) Rupture for nominal diameter > 150 mm	1E-07
Pressure relief valves — outflow at the maximum rate	2E-05
Process equipment	
(1) Pumps — catastrophic failure	1E-04
(2) Compressors with gasket — catastrophic failure	1E-04
(3) Heat exchanger — instantaneous release of entire contents from plate heat exchanger	5E-05
Transfer equipment — rupture of loading/unloading arm	3E-08

15.6 Release Probabilities and Conditional Probabilities.

15.6.1* The annual probability of LNG and other hazardous material releases from various equipment, for scenarios identified in Sections 15.4.1 and 15.4.2, shall be based on Table 15.6.1.

15.6.2 Site-specific modifications to the probability values in Table 15.6.1 shall be considered and, if used in subsequent analysis, shall be approved.

15.6.3 The conditional probability for each type of hazardous behavior, identified pursuant to the requirements in 15.5.2.4, shall be obtained from the AHJ approved conditional probability databases.

15.6.4 The details of values of probabilities used in the calculations and the sources of data shall be documented.

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15.7 Environmental Conditions and Occurrence Probabilities.

15.7.1 Site specific statistics on the environmental conditions shall be gathered either by direct measurements at the site for periods of time acceptable to obtain statistically meaningful data or from the nearest meteorological station.

15.7.2 The frequency of occurrence of different weather and other environmental parameters with conditional probabilities of occurrence of 25 percent, 50 percent, 75 percent and 99 percent shall be documented and considered in hazard calculations. These environmental parameters shall include wind speed, wind direction, atmospheric temperature, atmospheric relative humidity, and ground/water substrate temperature (if available).

15.7.3 Topographic and structural features in the vicinity of the proposed plant site that impact on the consequence of the released fluid shall be considered in the assessment of hazards. These features include, but are not limited to, liquid momentum for dike overtopping assessment, aerodynamic roughness of the site and surrounding area for dispersion behavior of vapors, and congestion due to plants, shrubs, and trees and its effect on potential vapor explosions.

15.7.4 The location and characteristics of vapor ignition sources in and around the plant shall be surveyed and documented as follows:

(1) The probabilities of ignition sources being active during the dispersion of a vapor cloud shall be assessed and approved
(2) The probabilities, including conditional probabilities of occurrence of various environmental parameters, determined pursuant to the requirements of 15.7.1 through 15.7.4 shall be documented.

15.8 Hazard and Consequence Assessment.

15.8.1 The hazard consequences of releases identified pursuant to the requirements in 15.4 shall be assessed.

15.8.2 For each identified scenario of release, type of hazard behavior, weather, and environmental or other condition (e.g., time to detect, response time, blow-down, ignition of a vapor cloud at different distances, effects of obstructions, effects of passive mitigation techniques) impacting the hazard areas or hazard distances shall be determined by accepted methods, including those identified in 5.3.3.4 through 5.3.3.9.

15.8.3 The following types of hazards and calculations of extent of hazard shall be considered, as a minimum:

(1) Distance to limit concentration levels arising from gas/vapor dispersion
(2) Distance to limit heat flux or heat dosage levels arising from pool fire exposures
(3) Distance to limit heat flux or heat dosage levels arising from vapor fires
(4) Distance to limit heat flux or heat dosage levels arising from fireballs
(5) Distance to limit overpressure levels arising from explosions
(6) Distances to other hazards from rapid phase transition (RPT), toxic releases and so forth

15.8.3.1 Potential cascading damages from primary release scenarios identified in 15.5.1 within the plant boundaries shall be considered and evaluated. If the assessment identifies significant hazards from cascading in-plant failures or external out-of-plant events, the risk calculation shall include the cascading effects.

Table 15.8.4.1 Radiant Heat Flux and Thermal Dosage Outside the Plant Boundary

Maximum Heat Flux Level (kW/m^2)	Maximum Modified Dosage Unit ($[kW/m^2]^{4/3}$ t)	Consequences
5.0	500	At least 10 persons would suffer 2nd degree skin burns on at least 10% of their bodies within 30 seconds of exposure to the fire.
5.0	300	At least one person inside the building would suffer 2nd degree skin burns on at least 10% of the body within 30 seconds of exposure to the fire.
32	N/A	Loss of strength of structural steel exposed to the fire to an extent that its primary load-bearing capacity is reduced significantly over the duration of LNG fire being analyzed.

15.8.4 The distances to various types of hazards shall be calculated using mathematical models in accordance with 15.8.4.1 through 15.8.4.4.

15.8.4.1 Distances to safe levels of radiant heat fluxes and modified thermal dosage values specified in Table 15.8.4.1 and Table 15.8.4.2 shall be calculated with a model that meets the following criteria:

(1) Takes into account the physical phenomena observed, and has been validated with available experimental data, including applicable experimental LNG fire published in the literature
(2) Has been published in an archival, peer-reviewed scientific journal in the related scientific/engineering disciplines including, but not limited to, fluid dynamics, heat transfer, combustion, or fire science
(3) Has been verified to accurately represent the physics
(4) Has a scientific assessment of the details of the physics, analysis, and execution process
(5) Has been approved by the AHJ

15.8.4.2* Distances to vapor dispersion to concentrations equal to the lower flammability limit (LFL) (volume concentration value 5 percent) shall be calculated using a model that is acceptable for use by the AHJ or a model that has been evaluated by an independent body using the Model Evaluation Protocol facilities published by the Fire Protection Research Foundation report "Evaluating Vapor Dispersion Models for Safety Analysis of LNG Facilities," 2007. Alternatively, distances to the occurrences of ignition of a vapor cloud shall be calculated using a methodology that is acceptable by the AHJ.

15.8.4.3 Hazard distances for damage criteria specified in Table 15.8.4.3 for scenarios of vapor cloud explosions shall be based on mathematical models approved by the AHJ.

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Table 15.8.4.2 Criteria for Property Damage Due to Radiant Heat from Fires

Exposed structure	Type of construction/ occupancy	Threshold damage criteria
Adjacent LNG container	Reinforced concrete	(1) Temperature of no part of the exposed concrete outer surface of the container structure shall exceed 570°F (300°C) over the duration of the fire. (2) Temperature of steel reinforcements in pre-stressed concrete shall not exceed 1000°F (540°C) over the duration of the fire.
Steel structures		Temperature shall not exceed 1000°F (540°C) over the duration of the fire.
Wooden structures		Net heat flux into the structure shall not exceed 8115 Btu/hr-ft^2 (26,500 w/m^2) for unpiloted ignition or 4660 Btu/hr-ft^2 (14,700 w/m^2) for piloted ignition.

Table 15.8.4.3 Blast Damage Criteria

Overpressure Damage Category	Reflected Damage Overpressure (N/m^2)	
	Lower Limit	Upper Limit
Window glass damage	250	4,000
Damage to doors, cladding, and persons	5,000	10,000
Severe structural damage to buildings	15,000	20,000
Severe injury to people	25,000	50,000*

*Complete demolition of a building.

15.8.4.4 RPT and other phenomena hazard distances shall be determined with models approved by the AHJ.

15.8.5 For each identified scenario of release and type of hazard identified in Section 15.5 and hazard distances or areas evaluated in Section 15.8, the total number of persons located within the hazard distance or area shall be enumerated using public demographic or census data or other methodology approved by the AHJ.

15.8.6 Other hazard criteria for exposure to persons and property damage from potential exposures to different types of hazards indicated in Annex A shall be used as a guide in the hazard assessment required under Section 15.8.

15.8.7 The values of the hazard criteria used and the scientific justification or source of information shall be documented.

15.9 Risk Result Presentation.

15.9.1 Risk Contours of Constant Individual Risks.

15.9.1.1 The individual risk values for various combinations of release scenarios, materials released, and environmental and substrate conditions shall be combined with the various event occurrence probabilities to calculate the risk posed to an individual inside the plant boundary and outside the plant boundary.

15.9.1.2 Individual risk values shall be calculated for various distances in different compass directions from the event location.

15.9.1.3 Contours of constant individual risks shall be developed.

15.9.1.4 The uncertainty in calculating the individual risks shall be enumerated and presented.

15.9.2 Societal Risks on F-N Diagrams.

15.9.2.1 The potential number of exposed persons that may occur as a result of an event and combination of other parameters shall be determined using the approved local demographic data and the calculated hazard distances or areas.

15.9.2.2* The societal risk values shall be presented in the form of cumulative annual frequency of exceedance of a specified number of fatalities vs. number of fatalities.

15.9.2.3 Estimated error values in the calculation of both the cumulative annual frequency of specified casualty exceedance and the number of casualties shall be indicated on the F-N plots. The details of the error estimations shall be documented.

15.10 Risk Tolerability Criteria.

15.10.1 Individual risk acceptability criteria specified in Table 15.10.1 shall be used.

15.10.2* The societal risk acceptability criteria specified in Table 15.10.2 and illustrated in Figure 15.10.2 shall be used.

15.10.3 The acceptability criteria used in sections 15.10.1 and 15.10.2 shall be suitably modified taking into consideration the geographic location of the site and other local risk acceptability norms, if any.

15.10.4 The criteria used for the tolerable individual risk and the societal risk, as modified, shall be approved.

15.11 Risk Mitigation Approaches.

15.11.1* In the case that the calculated risks are in the unacceptable region or lie in regions between the lower and upper bound acceptable ranges, reduction of risks to tolerable levels shall be considered by implementing additional mitigation measures.

15.11.2* Mitigation measures shall include, but not limited to, incorporation of the latest technology and instruments in plant design, improved equipment layout design, use of upgraded equipment, improved spill notification and emergency response procedures, and operational changes.

15.11.3* Mitigation measures proposed shall be approved.

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Table 15.10.1 Criteria for Tolerability of Individual Risk (IR) from Injury Due to Exposure to Dangerous Dose or Higher

Criterion Annual Frequency	Remarks
Zone 1 $IR \le 10^{-5}$	Not permitted: Residential, office, and retail Permitted: Occasionally occupied developments (e.g., pump houses, transformer stations)
Zone 2 $10^{-6} \le IR \le 10^{-5}$	Not permitted: Shopping centers, large-scale retail outlets, restaurants, etc. Permitted: Work places, retail and ancillary services, residences in areas of 28 to 90 persons/hectare density
Zone 3 $3 \times 10^{-7} \le IR \le 10^{-6}$	Not permitted: Churches, schools, hospitals, major public assembly areas, and other sensitive establishments Permitted: All other structures and activities

Table 15.10.2 Criteria for Tolerability of Societal (Fatalities) Risks

Criterion Annual Frequency (CAF)	Remarks
$F = 10^{-4}$, $N = 10$ Slope = –1	Unacceptable above the line defined by the CAF column
$F = 10^{-6}$, $N = 10$ Slope = –1	Broadly acceptable below the line defined by the CAF column
ALARP	Acceptable with AHJ review in the region between the two lines above

(F = Annual probability of experiencing N or more fatalities)

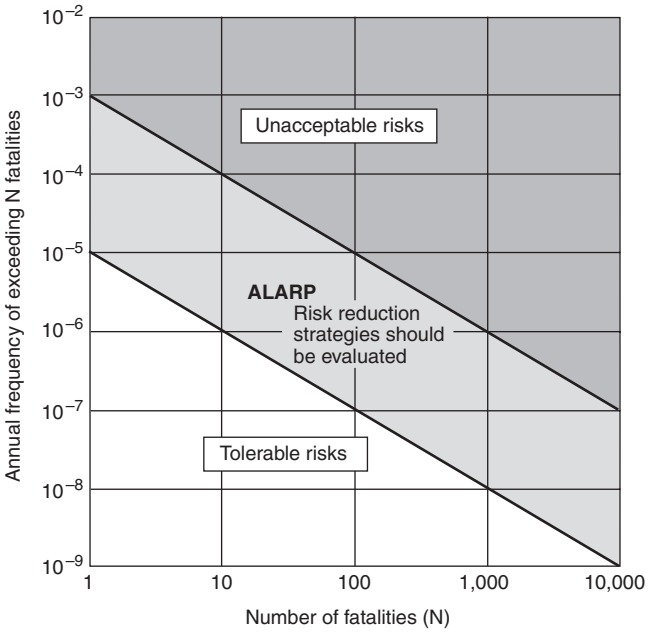


FIGURE 15.10.2 Acceptability Regions of Societal (Injury) Risk in the F-N Domain.

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 3.3.15. For information on the use of LNG as a vehicle fuel, see NFPA 52, *Vehicular Gaseous Fuel Systems Code*.

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

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(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.

A.3.3.5.3.1 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 625, *Tank Systems for Refrigerated Liquefied Gases,* for further definition.

A.3.3.5.3.2 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 625 for further definition.

A.3.3.5.3.4 Single Containment Tank System. A single containment tank system incorporates a liquid-tight container and a vapor-tight container. It can be a liquidtight and vaportight 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 vaportight. 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 625 for further definition.

A.3.3.11 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.3.3.26 Transfer Area. Transfer areas do not include product sampling devices or permanent plant piping.

A.3.3.28 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.4.6 The provisions of 4.6 do not require inherently noncombustible materials to be tested in order to be classified as noncombustible materials. [***101,*** A.4.6.13]

A.4.6.1(1) Examples of such materials include steel, concrete, masonry, and glass. [***101,*** A.4.6.13.1(1)]

A.5.2 The following factors should be considered in the selection of plant site locations:

(1) Provision for minimum clearances as stated in this standard between LNG containers, flammable refrigerant storage tanks, flammable liquid storage tanks, structures,

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and plant equipment, with respect to both plant property lines and each other
(2) The degree that the plant can, within limits of practicality, be protected against forces of nature
(3) Other factors applicable to the specific site that have a bearing on the safety of plant personnel and the surrounding public

The review of such factors should include an evaluation of potential incidents and safety measures incorporated in the design or operation of the facility.

A.5.2.4 New plant site locations should avoid flood hazard areas. 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. Where encroachment into a flood hazard area is unavoidable, measures to minimize flood exposure and damage to the site and facilities should be investigated. Flood loads are outlined in ASCE 7, *Minimum Design Loads 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.5.3.3.3 Methods that can be used to mitigate the effects of thermal radiation include the following:

(1) Affecting the burning rate of LNG
(2) Reducing the size of the LNG fire
(3) Reducing the radiant heat emission characteristics of the fire
(4) Impeding the transmission of the radiant heat from the fire to the exposed objects
(5) Other approved methods

A.5.3.3.4 Several models are available to determine the thermal radiation distance required by 5.3.3.4. These include but are not limited to, the following:

(1) The Gas Research Institute's GRI Report 0176, *LNGFIRE: A Thermal Radiation Model for LNG Fires*, which is also available as the "LNGFIRE III" computer model produced by GRI
(2) The "Large Size LNG Pool Fire Model" described in the U.S. DOT report, *Spectrum of Fires in an LNG Facility Assessments, Models and Consideration in Risk Evaluations*, developed under the U.S. DOT Contract DTRS56-04-T-005, December 2006, and the related computer code, Pool Fire Model Including Smoke Effects (PoFMISE)

These references are for informational purposes only. The information concerning these software models has not been independently verified, nor have the models been endorsed or certified by NFPA or any of its Technical Committees.

A.5.3.3.6 The 50 percent LFL level reflects the uncertainty associated with current modeling programs. One model that has been used to calculate methane concentrations in air is described in GRI Report 0242, *LNG Vapor Dispersion Prediction with the DEGADIS Dense Gas Dispersion Model*.

A.5.4.1(1) Examples of buildings and structures included in Classification I are control rooms, 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.

A.5.5 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.5.5.2 See API 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*, Appendix C, for further information.

A.5.6 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.5.8.5 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.6.5.6 For information on internal combustion engines or gas turbines exceeding 7500 horsepower per unit, see NFPA 850, *Recommended Practice for Fire Protection for Electric Generating Plants and High Voltage Direct Current Converter Stations*.

A.7.3.1.3 Operating requirements for prevention of stratification are located in Section 14.6.

A.7.3.1.7 ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases*, contains further information regarding decomissioning of concrete containment tanks. Additional consideration for continued outgasing of concrete should be considered in decomissioning procedures.

A.7.3.6.5.3 For double-wall, perlite-insulated tanks, the minimum pressure-relieving capacity can be the governing criterion for pressure relief valve sizing.

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A.7.3.6.7.3 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.7.3.7.1 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 620, can be used as guides for the subsurface investigation.

A.7.3.7.5(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 plant ground and lightning protection system. Grounding can make a cathodic protection system ineffective.

A.7.3.7.6(D) Moisture accumulation in the conduit can lead to galvanic corrosion or other forms of deterioration within the conduit or heating element.

A.7.4.1.1 API 625, Figure 11.2 provides acceptable information and format for a certification document. This form may be used to provide that compliance.

A.7.4.2.2 API 620 defines examination as either radiographic or ultrasonic examination.

A.7.4.4.4 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.

A.8.3.1 Because these vaporizers operate over a temperature range of –260°F to 212°F (–162°C to 100°C), the rules of the ASME *Boiler and Pressure Vessel Code*, Section I, Part PVG are not applicable.

A.8.4.5.2 Valves meeting this requirement should meet the testing requirements of API 607, *Fire Test for Quarter-turn Valves and Valves Equipped with Nonmetallic Seats,* or similar test.

A.9.1 Refer to 7.3.1.2 and Section 13.14 for piping that is part of an LNG tank

A.9.2.1 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.9.2.3 Particular consideration should be given where changes in size of wall thickness occur between pipes, fittings, valves, and components.

A.9.3.1.4 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.9.3.3.3 PFI ES-24, *Pipe Bending Methods, Tolerances, Process and Material Requirements,* can be used as a guide for all pipe bending.

A.9.4.2 Table 5.3.3.7 provides the size of the design spill, which should be considered when specifying the closing time of a powered valve operator.

A.9.4.2.6(1) Valves meeting this requirement would be designed to meet the testing requirements of API 607, or similar test.

A.9.4.2.9 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.9.4.4(2) 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.

A.9.6 For information on identification of piping systems, see ASME A 13.1, *Scheme for the Identification of Piping Systems.*

A.9.7.3.4 All branch connections shall be attached to the run pipe by full penetration groove welds. See paragraph 328.5.4(d) in ASME B 31.3.

A.9.8.1 The AGA publication *Purging, Principles and Practices* can be used as a guide.

A.9.10.1 49 CFR 193, "Liquefied Natural Gas" Subpart G, includes corrosion protection requirements applicable to the LNG facility.

A.9.11.8 Consideration shall be given to the installation of "witness" pieces to monitor the installed condition of material associated with "buried" pipe.

A.10.7.2 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 unloading points and to the effect those variations might have on the point of connection.

A.10.8.1 For information on grounding and bonding, see NFPA 77, *Recommended Practice on Static Electricity*, Section 5.4 and 6.1.3, and *NFPA 70, National Electrical Code.*

A.10.8.3 For information on stray currents, see API RP 2003, *Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents.*

A.10.8.4 For information on lightning protection, see NFPA 780, *Standard for the Installation of Lightning Protection Systems*, and API RP 2003.

A.11.5.3 The ESD required by 11.5.3 can be part of the facility ESD system, or it can be a separate ESD system specific to transfer operations.

A.12.2 For information on fire extinguishing systems, see the following:

(1) NFPA 10, *Standard for Portable Fire Extinguishers*
(2) NFPA 11, *Standard for Low-, Medium-, and High-Expansion Foam*
(3) NFPA 12, *Standard on Carbon Dioxide Extinguishing Systems*
(4) NFPA 12A, *Standard on Halon 1301 Fire Extinguishing Systems*
(5) NFPA 13, *Standard for the Installation of Sprinkler Systems*
(6) NFPA 14, *Standard for the Installation of Standpipe and Hose Systems*

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(7) NFPA 15, *Standard for Water Spray Fixed Systems for Fire Protection*
(8) NFPA 16, *Standard for the Installation of Foam-Water Sprinkler and Foam-Water Spray Systems*
(9) NFPA 17, *Standard for Dry Chemical Extinguishing Systems*
(10) NFPA 20, *Standard for the Installation of Stationary Pumps for Fire Protection*
(11) NFPA 22, *Standard for Water Tanks for Private Fire Protection*
(12) NFPA 24, *Standard for the Installation of Private Fire Service Mains and Their Appurtenances*
(13) NFPA 25, *Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems*
(14) NFPA 68, *Standard on Explosion Protection by Deflagration Venting*
(15) NFPA 69, *Standard on Explosion Prevention Systems*
(16) *NFPA 72, National Fire Alarm and Signaling Code*
(17) NFPA 750, *Standard on Water Mist Fire Protection Systems*
(18) NFPA 1961, *Standard on Fire Hose*
(19) NFPA 1962, *Standard for the Inspection, Care, and Use of Fire Hose, Couplings, and Nozzles and the Service Testing of Fire Hose*
(20) NFPA 1963, *Standard for Fire Hose Connections*
(21) NFPA 2001, *Standard on Clean Agent Fire Extinguishing Systems*

A.12.2.1 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.

A.12.2.2 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.12.2.2(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.12.2.2(9) Plant fire brigades are not required by this standard. Where the facility elects to have a fire brigade, NFPA 600, *Standard on Industrial Fire Brigades*, is required for protective equipment and training.

A.12.4.4 When installed as determined by the evaluation required in , the following detection system components should be designed, installed, documented, tested, and maintained in accordance with *NFPA 72, National Fire Alarm and Signaling Code*, or as approved by the AHJ:

(1) Initiating devices (detectors – smoke, flame, heat, etc.)
(2) Fire system controllers and monitoring panels
(3) Notification appliances (strobes, sirens, etc)
(4) Fire system activation devices on installed extinguishment/suppression systems (water deluge, fixed dry chemical systems, etc.)
(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 12.2.1

A.12.6.1 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 12.2.1.

A.12.8.1 Protective clothing for normal liquid transfer operations should include cryogenic gloves, safety glasses, face shields, and coveralls or long-sleeve shirts.

A.12.8.3 Information concerning confined entry practices and procedures can be found in 29 CFR 1910.146, "Labor"; Canadian Federal Employment and Labor Statutes, Part II; and any local, state, or provincial requirements and standards that apply.

A.12.8.4 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.13.6.6 For information on corrosion protection, see NACE SP 0169, *Control of External Corrosion on Underground or Submerged Metallic Piping Systems*.

A.13.7.2 Valves meeting this requirement are designed to meet the testing requirements of API 607 or similar test.

A.13.14.2 LNG facilities within the United States should at a minimum adhere to Section 9.7 requirements for examination and testing of piping.

A.13.18.3.2 Extinguishment of gaseous fires can cause a buildup of flammable vapors that can result in a re-ignition of the gases or an explosion, causing damage beyond that resulting from the fire itself. Normally the best method for suppression of a gaseous fuel fire is shutoff of the fuel supply, which results in extinguishment of the fire by fuel starvation. In cases where the control equipment is involved in the fire or where damage to equipment or structures will result in loss of control or loss of life, the fire may need to be extinguished. In those cases, vapor control must be implemented immediately to prevent an accumulation of vapors that could result in a re-ignition or an explosion.

A.14.1 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.

A.14.2.2(7) Definitions of safety-related malfunctions are given in 49 CFR 191, "Transportation," for LNG plants under the jurisdiction of the U.S. Department of Transportation under 49 CFR 193, "Liquefied Natural Gas Facilities: Federal Safety Standards."

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A.14.5.1 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.

A.14.5.5.4 Several methods can be used for purging large containers into and out of service.

Several references cover the purging of large containers. Refer to the AGA publication *Purging, Principles and Practice*.

A.14.5.5.4.5 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*.

A.14.6.7.4 For information on operation of piers, docks, and wharves, see NFPA 30, *Flammable and Combustible Liquids Code*.

A.14.6.7.4.3 The ship's existing lifesaving appliances (i.e., lifeboats) can fulfill the requirement for emergency egress.

A.14.8.10.4(3) Normally, dry chemical–type fire extinguishers are recommended for gas fires.

A.14.8.13.4 API RP 651, *Cathode Protection of Aboveground Petroleum Storage Tanks*, provides guidance in the use of cathodic protection.

A.15.2.2 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 15.10.2. Tolerable individual and societal risk criteria are then subject to the approval of the AHJ.

A.15.3.1 Refer to United Kingdom Health and Safety Executive publication "Reducing Risks, Protecting People" available for free download from http://www.hse.gov.uk/risk/theory/r2p2.pdf.

A.15.3.3 A serious injury is any detrimental outcome of an event to a person exposed to or affected by the LNG or other in-plant hazardous material release, which results in the person requiring first-aid (to preserve life) or being treated and kept in a medical facility for at least 24 hours.

A.15.4.1 The list of methodologies here is not intended to override the Equivalency clause of 1.3. Users, with sufficient documentation and approval of the authority having jurisdiction, should be permitted to use alternate methodologies.

A.15.6.1 Some additional references for failure rate data of equipment items are listed below:

(1) OREDA: Contains data for use in reliability, availability and maintainability studies - failure rates, failure mode distribution and repair times for equipment (Reference: OREDA, Offshore Reliability Data Handbook 4th Edition, SINTEF, 2002)
(2) Reliability Data for Control and Safety Systems, 1998, SINTEF Industrial Management, Trondheim, Norway
(3) CCPS Process Equipment Reliability Database. The database is only open to CCPS members but some data are available in the book Guidelines for Process Equipment Reliability Data (CCPS 1989). Guidelines for Process Equipment Reliability Data, CCPS, 1989
(4) FMD-97, Failure mode / Mechanism Distributions, 1997, Reliability Analysis Center, Rome, NY
(5) NPRD-95, Nonelectronic Parts Reliability Data, 1995, Reliability Analysis Center, Rome, NY
(6) IEEE Std. 500, IEEE Guide To The Collection and Presentation Of Electrical, Electronic, Sensing Component, And Mechanical Equipment Reliability Data For Nuclear-Power Generating Stations, 1984, IEEE, New York, NY
(7) Johnson, E.M. and Welker, J. R., "Development of an Improved LNG Plant Failure Rate Data Base", GRI-80/0093, Gas Research Institute, Chicago, IL, USA, 1980.

Some references for leak frequency data are listed below:

(1) Hydrocarbon Releases (HCR) Database, UK Health and Safety Executive, with the following associated documents:
(2) Offshore hydrocarbon releases statistics and analysis, 2002, HID statistics report, HSR 2002 002, February 2003, HSE
(3) Revised guidance on reporting of offshore hydrocarbon releases, OTO 96 956, November 1996, HSE
(4) Supplementary Guidance for Reporting Hydrocarbon Releases, September 2002, UKOOA
(5) MHIDAS (Major Hazard Incident Data Service): database maintained by AEA Technology, Warrington
(6) Purple Book, Guidelines for quantitative risk assessment – CPR 18E, RVIM, 1999
(7) E & P Forum Hydrocarbon Leak Database (Reference: Quantitative risk assessment datasheet directory, E Forum Report N0 11.8/250, October 1996)
(8) Lees "Loss Prevention in the Process Industry." Loss Prevention in the Process Industry, Frank P Lees, 2nd edition, 1996, ISBN 0750615478 (Note: 3rd edition published in 2005)

A.15.8.4.2 Distance to the LFL should take into consideration the validation results in the model evaluation protocol (MEP), but distances to the LFL should not be adjusted to less than the predicted distance to the LFL of the model.

A.15.9.2.2 The fatalities alluded to in this section are only those caused as a direct consequence of, and occurring within a short period of time after exposure to hazards associated with LNG or other hazardous materials released from a LNG plant.

A.15.10.2 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.15.10.2.

A.15.11.1 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 facility. Inherent safety is the use of mitigations that avoid the hazard rather than attempt to control the hazardous event or process. Kletz in *Plant Design for Safety: A User friendly Approach* (New York: Hemisphere Publishing, 1991) states the basic principles of inherent safety as follows: These principles are based upon a hierarchy starting with intensification and ending with administrative controls and procedures. This hierarchy is explained further below.

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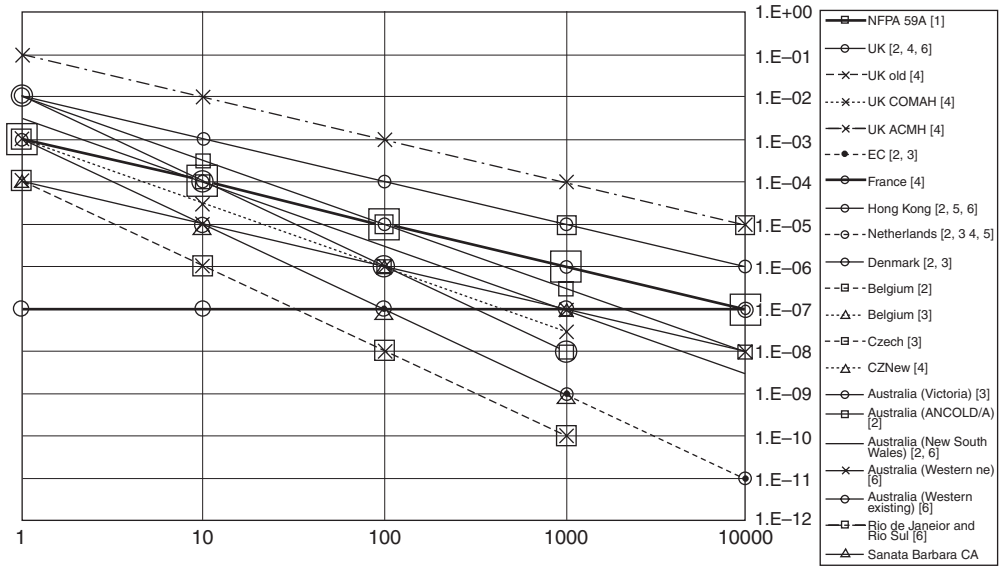


FIGURE A.15.10.2 Societal Risk Tolerance Criteria Used by Different Jurisdictions.

(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 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, for example, 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 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.

A.15.11.2 With regard to the reduction of risk to persons outside the boundaries of the facility, the basic principles illustrated in A.15.11.1 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 facility. Revision of the plant layout and orientation should be considered to increase the separation distance. When changes to the 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 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 are an effective way to reduce the impact to the general public from the facility.
(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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A.15.11.3 Some examples of mitigation measures are provided below:

(1) *Tier 1: Remove the hazard.*
   (a) Plant spacing and layout
   (b) Spill containment

(2) *Tier 2: Reduce the amount of hazardous substance/prevent the release.*
   (a) Design of equipment, including relief valve design, redundancy, and so forth
   (b) Valve arrangements
   (c) Safety instrumented systems, including changes to safety integrity levels, ESD logic, alarm management, and so forth
   (d) Fire and gas systems, including system reliability, F & G logic, response time, detector coverage, and alarm management
   (e) Fire protection equipment, including passive and active mitigation techniques

(3) *Tier 3: Additional procedures or controls to mitigate the risk.*
   (a) Maintenance and operating procedures
   (b) Security procedures and equipment
   (c) Emergency response actions

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 7.4.4.6 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).

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 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 criteria (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 facility 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 625, API 620 (Appendix L), and ACI 376, which have 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 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 620 and ACI 376. 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 the ALE level of loading while holding the volume, *V*, as specified in 7.4.4.7. 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.

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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. 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 7.5.2.1 , 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 occupancy category in accordance with 5.4.1 and 5.4.2 and ASCE 7.

Annex C Security

This annex is not a part of the requirements of this NFPA document but is included for informational purposes only.

C.1 General. This annex is reprinted from Title 49 of the Code of Federal Regulations, Part 193, Subpart J, Appendix J. The references herein are found in 49 CFR 193 "Transportation." These federal requirements are applicable to LNG plants in the United States under the jurisdiction of the Department of Transportation.

Sec. 193.2901 Scope. This subpart prescribes requirements for security at LNG plants. However, the requirements do not apply to existing LNG plants that do not contain LNG.

Sec. 193.2903 Security procedures. Each operator shall prepare and follow one or more manuals of written procedures to provide security for each LNG plant. The procedures must be available at the plant in accordance with Sec. 193.2017 and include at least:

(1) A description and schedule of security inspections and patrols performed in accordance with Sec. 193.2913;
(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; and
(7) Liaison with local law enforcement officials to keep them informed about current security procedures under this section.

Sec. 193.2905 Protective enclosures.

(1) The following facilities must be surrounded by a protective enclosure:
   (a) Storage tanks;
   (b) Impounding systems;
   (c) Vapor barriers;
   (d) Cargo transfer systems;
   (e) Process, liquefaction, and vaporization equipment;
   (f) Control rooms and stations;
   (g) Control systems;
   (h) Fire control equipment;
   (i) Security communications systems; and
   (j) Alternative power sources.

   The protective enclosure may be one or more separate enclosures surrounding a single facility or multiple facilities.
(2) Ground elevations outside a protective enclosure must be graded in a manner that does not impair the effectiveness of the enclosure.
(3) Protective enclosures may not be located near features outside of the facility, such as trees, poles, or buildings, which could be used to breach the security.
(4) At least two accesses must be provided in each protective enclosure and be located to minimize the escape distance in the event of emergency.
(5) Each access must be locked unless it is continuously guarded. During normal operations, an access may be unlocked only by persons designated in writing by the operator. During an emergency, a means must be readily available to all facility personnel within the protective enclosure to open each access.

Sec. 193.2907 Protective enclosure construction.

(1) Each protective enclosure must have sufficient strength and configuration to obstruct unauthorized access to the facilities enclosed.
(2) Openings in or under protective enclosures must 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.

Sec. 193.2909 Security communications. A means must be provided for:

(1) Prompt communications between personnel having supervisory security duties and law enforcement officials; and
(2) Direct communications between all on-duty personnel having security duties and all control rooms and control stations.

Sec. 193.2911 Security lighting. Where security warning systems are not provided for security monitoring under Sec. 193.2913, the area around the facilities listed under Sec. 193.2905(a) and each protective enclosure must be illuminated with a minimum in service lighting intensity of not less than 2.2 lux (0.2 ft candles) between sunset and sunrise.

Sec. 193.2913 Security monitoring. Each protective enclosure and the area around each facility listed in Sec. 193.2905(a) must be monitored for the presence of unauthorized persons. Monitoring must be by visual observation in accordance with the schedule in the security procedures under Sec. 193.2903(a) or by security warning systems that continuously transmit data to an attended location. At an LNG plant with less than 40,000 m^3 (250,000 bbl) of storage capacity, only the protective enclosure must be monitored.

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Sec. 193.2915 Alternative power sources. An alternative source of power that meets the requirements of Sec. 193.2445 must be provided for security lighting and security monitoring and warning systems required under Secs. 193.2911 and 193.2913.

Sec. 193.2917 Warning signs.

(1) Warning signs must be conspicuously placed along each protective enclosure at intervals so that at least one sign is recognizable at night from a distance of 30 m (100 ft) from any way that could reasonably be used to approach the enclosure.
(2) Signs must be marked with at least the following on a background of sharply contrasting color:

The words "NO TRESPASSING," or words of comparable meaning.

Annex D Training

This annex is not a part of the requirements of this NFPA document but is included for informational purposes only.

D.1 General. This annex is reprinted from Title 49 of the Code of Federal Regulations, Part 193, Subpart H. The references herein are found in 49 CFR 193, "Transportation." It is applicable to LNG plants in the United States under the jurisdiction of the Department of Transportation.

Sec. 193.2701 Scope. This subpart prescribes requirements for personnel qualifications and training.

Sec. 193.2703 Design and fabrication. For the design and fabrication of components, each operator shall use —

(1) With respect to design, persons who have demonstrated competence by training or experience in the design of comparable components.
(2) With respect to fabrication, persons who have demonstrated competence by training or experience in the fabrication of comparable components.

Sec. 193.2705 Construction, installation, inspection, and testing.

(1) Supervisors and other personnel utilized for construction, installation, inspection, or testing must have demonstrated their capability to perform satisfactorily the assigned function by appropriate training in the methods and equipment to be used or related experience and accomplishments.
(2) Each operator must periodically determine whether inspectors performing duties under Sec. 193.2307 are satisfactorily performing their assigned function.

Sec. 193.2707 Operations and maintenance.

(1) Each operator shall utilize for operation or maintenance of components only those personnel who have demonstrated their capability to perform their assigned functions by —
    (a) Successful completion of the training required by Secs. 193.2713 and 193.2717; and
    (b) Experience related to the assigned operation or maintenance function; and
    (c) Acceptable performance on a proficiency test relevant to the assigned function.
(2) A person who does not meet the requirements of paragraph (a) of this section may operate or maintain a component when accompanied and directed by an individual who meets the requirements.
(3) Corrosion control procedures under Sec. 193.2605(b), including those for the design, installation, operation, and maintenance of cathodic protection systems, must be carried out by, or under the direction of, a person qualified by experience and training in corrosion control technology.

Sec. 193.2709 Security. Personnel having security duties must be qualified to perform their assigned duties by successful completion of the training required under Sec. 193.2715.

Sec. 193.2711 Personnel health. Each operator shall follow a written plan to verify that personnel assigned operating, maintenance, security, or fire protection duties at the LNG plant do not have any physical condition that would impair performance of their assigned duties. The plan must be designed to detect both readily observable disorders, such as physical handicaps or injury, and conditions requiring professional examination for discovery.

Sec. 193.2713 Training: operations and maintenance.

(1) Each operator shall provide and implement a written plan of initial training to instruct —
    (a) All permanent maintenance, operating, and supervisory personnel —
        i. About the characteristics and hazards of LNG and other flammable fluids used or handled at the facility, including, with regard to LNG, low temperatures, flammability of mixtures with air, odorless vapor, boiloff characteristics, and reaction to water and water spray;
        ii. About the potential hazards involved in operating and maintenance activities; and
        iii. To carry out aspects of the operating and maintenance procedures under Secs. 193.2503 and 193.2605 that relate to their assigned functions; and
    (b) All personnel —
        i. To carry out the emergency procedures under Sec. 193.2509 that relate to their assigned functions; and
        ii. To give first-aid; and
    (c) All operating and appropriate supervisory personnel —
        i. To understand detailed instructions on the facility operations, including controls, functions, and operating procedures; and
        ii. To understand the LNG transfer procedures provided under Sec. 193.2513.
(2) A written plan of continuing instruction must be conducted at intervals of not more than two years to keep all personnel current on the knowledge and skills they gained in the program of initial instruction.

Sec. 193.2715 Training: security.

(1) Personnel responsible for security at an LNG plant must be trained in accordance with a written plan of initial instruction to:
    (a) Recognize breaches of security;
    (b) Carry out the security procedures under Sec. 193.2903 that relate to their assigned duties;

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(c) Be familiar with basic plant operations and emergency procedures, as necessary to effectively perform their assigned duties; and

(d) Recognize conditions where security assistance is needed.

(2) A written plan of continuing instruction must be conducted at intervals of not more than two years to keep all personnel having security duties current on the knowledge and skills they gained in the program of initial instruction.

Sec. 193.2717 Training: fire protection.

(1) All personnel involved in maintenance and operations of an LNG plant, including their immediate supervisors, must be trained in accordance with a written plan of initial instruction, including plant fire drills, to:

(a) Know and follow the fire prevention procedures under Sec. 193.2805(b);

(b) Know the potential causes and areas of fire determined under Sec. 193.2805(a);

(c) Know the types, sizes, and predictable consequences of fire determined under Sec. 193.2817(a); and

(d) Know and be able to perform their assigned fire control duties according to the procedures established under Sec. 193.2509 and by proper use of equipment provided under Sec. 193.2817.

(2) A written plan of continuing instruction, including plant fire drills, must be conducted at intervals of not more than two years to keep personnel current on the knowledge and skills they gained in the instruction under paragraph (a) of the section.

(3) Plant fire drills must provide personnel hands-on experience in carrying out their duties under the fire emergency procedures required by Sec. 193.2509.

Sec. 193.2719 Training: records.

(1) Each operator shall maintain a system of records which —

(a) Provide evidence that the training programs required by this subpart have been implemented; and

(b) Provide evidence that personnel have undergone and satisfactorily completed the required training programs.

(c) Records must be maintained for one year after personnel are no longer assigned duties at the LNG plant.

Annex E Informational References

E.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.

E.1.1 NFPA Publications. National Fire Protection Association, 1 Batterymarch Park, Quincy, MA 02169-7471.

NFPA 10, *Standard for Portable Fire Extinguishers*, 2010 edition.

NFPA 11, *Standard for Low-, Medium-, and High-Expansion Foam*, 2010 edition.

NFPA 12, *Standard on Carbon Dioxide Extinguishing Systems*, 2011 edition.

NFPA 12A, *Standard on Halon 1301 Fire Extinguishing Systems*, 2009 edition.

NFPA 13, *Standard for the Installation of Sprinkler Systems*, 2013 edition.

NFPA 14, *Standard for the Installation of Standpipe and Hose Systems*, 2010 edition.

NFPA 15, *Standard for Water Spray Fixed Systems for Fire Protection*, 2012 edition.

NFPA 16, *Standard for the Installation of Foam-Water Sprinkler and Foam-Water Spray Systems*, 2011 edition.

NFPA 17, *Standard for Dry Chemical Extinguishing Systems*, 2009 edition.

NFPA 20, *Standard for the Installation of Stationary Pumps for Fire Protection*, 2013 edition.

NFPA 22, *Standard for Water Tanks for Private Fire Protection*, 2008 edition.

NFPA 24, *Standard for the Installation of Private Fire Service Mains and Their Appurtenances*, 2013 edition.

NFPA 25, *Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems*, 2011 edition.

NFPA 30, *Flammable and Combustible Liquids Code*, 2012 edition.

NFPA 52, *Vehicular Gaseous Fuel Systems Code*, 2010 edition.

NFPA 68, *Standard on Explosion Protection by Deflagration Venting*, 2007 edition.

NFPA 69, *Standard on Explosion Prevention Systems*, 2008 edition.

NFPA 70®, *National Electrical Code®*, 2011 edition.

NFPA 72®, *National Fire Alarm and Signaling Code*, 2013 edition.

NFPA 77, *Recommended Practice on Static Electricity*, 2007 edition.

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

NFPA 600, *Standard on Industrial Fire Brigades*, 2010 edition.

NFPA 750, *Standard on Water Mist Fire Protection Systems*, 2010 edition.

NFPA 780, *Standard for the Installation of Lightning Protection Systems*, 2011 edition.

NFPA 850, *Recommended Practice for Fire Protection for Electric Generating Plants and High Voltage Direct Current Converter Stations*, 2010 edition.

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

NFPA 1962, *Standard for the Inspection, Care, and Use of Fire Hose, Couplings, and Nozzles and the Service Testing of Fire Hose*, 2008 edition.

NFPA 1963, *Standard for Fire Hose Connections*, 2009 edition.

NFPA 2001, *Standard on Clean Agent Fire Extinguishing Systems*, 2012 edition.

E.1.2 Other Publications.

E.1.2.1 ACI Publications. American Concrete Institute, P.O. Box 9094, Farmington Hills, MI 48333.

ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases*, 2010.

E.1.2.2 AGA Publications. American Gas Association, 400 North Capitol Street, NW, Washington, DC 20001.

Purging, Principles and Practice, 1975.

E.1.2.3 API Publications. American Petroleum Institute, 1220 L Street, NW, Washington, DC 20005-4070.

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API 607, *Fire Test for Quarter-turn Valves and Valves Equipped with Nonmetallic Seats,* 2010.

API 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks,* 2008 with 2009 addendum.

API 625, *Tank Systems for Refrigerated Liquefied Gas Storage,* 2010.

API RP 651, *Cathode Protection of Aboveground Petroleum Storage Tanks,* 2007.

API RP 2003, *Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents,* 2008.

E.1.2.4 ASCE Publications. American Society of Civil Engineers, 1801 Alexander Bell Drive, Reston, VA 20191-4400.

ASCE 7, *Minimum Design Loads for Buildings and Other Structures,* 2010.

E.1.2.5 ASME Publications. American Society of Mechanical Engineers, Three Park Avenue, New York, NY 10016-5990.

ASME *Boiler and Pressure Vessel Code,* 2007.

ASME A 13.1, *Scheme for the Identification of Piping Systems,* 2007.

ASME B 31.3, *Process Piping,* 2008.

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Canadian Foundation Engineering Manual, 1993.

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GRI Report 0242, *LNG Vapor Dispersion Prediction with the DEGADIS Dense Gas Dispersion Model,* 1989.

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NACE SP 0169, *Control of External Corrosion on Underground or Submerged Metallic Piping Systems,* 2007.

E.1.2.9 PFI Publications. Piping Fabrication Institute, 511 Ave of Americas, #611, New York, NY 10011.

ES-24, *Pipe Bending Methods, Tolerances, Process and Material Requirements,* 2010.

E.1.2.10 U.S. Government Publications. U.S. Government Printing Office, Washington, DC 20402.

Title 29, Code of Federal Regulations, Part 1910.146, "Permit-Required Confined Spaces," January 14, 1993, effective April 15, 1993.

Title 49, Code of Federal Regulations, Part 191, "Transportation of Natural and Other Gas by Pipeline; Annual Reports, Incident Reports, and Safety-Related Condition Reports."

Title 49, Code of Federal Regulations, Part 193, "Liquefied Natural Gas Facilities: Federal Safety Standards."

U.S. DOT Report DTRS56-04-T-0005, *Spectrum of Fires in an LNG Facility Assessments, Models and Consideration in Risk Evaluations,* December 2006.

E.1.2.11 Other Publications.

Guidelines for Quantitative Risk Assessment (TNO Purple Book).

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E.3 References for Extracts in Informational Sections.

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Formal Interpretation

NFPA 59A

Liquefied Natural Gas (LNG)

2013 Edition

Reference: Chapter 13
F.I. No.: 59A-96-1

Question: Is it the intent of the LNG Committee to require that Chapter 10 of NFPA 59A be applicable to all facilities using LNG conta iners designed and constructed in accordance with the ASME Boiler and Pressure Vessel Code for use in commercial and industrial applications as well as vehicle refueling facilities?

Answer: Yes.

Issue Edition: 1996
Reference: Chapter 10
Issue Date: December 23, 1997
Effective Date: January 12, 1998

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Tentative Interim Amendment

NFPA® 59A

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

2013 Edition

Reference: Table 15.6.1 and Table 15.8.4.1
TIA 13-1
(SC 13-3-7/TIA Log #1090)

Pursuant to Section 5 of the NFPA *Regulations Governing the Development of NFPA Standards*, the National Fire Protection Association has issued the following Tentative Interim Amendment to NFPA 59A, *Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG),* 2013 edition. The TIA was processed by the Technical Committee on Liquefied Natural Gas, and was issued by the Standards Council on March 7, 2013, with an effective date of March 27, 2013.

A Tentative Interim Amendment is tentative because it has not been processed through the entire standards-making procedures. It is interim because it is effective only between editions of the standard. A TIA automatically becomes a public input of the proponent for the next edition of the standard; as such, it then is subject to all of the procedures of the standards-making process.

1. *Modify the format of Table 15.6.1 and add descriptive units for probability of failure of piping as follows:*

Table 15.6.1 Example Component Failure Database

Component	Annual Probability of Failure
Atmospheric Cryogenic Tanks	
(1) Instantaneous failure of primary container and outer shell, release of entire contents (single containment tank)	5E-07
(2) Instantaneous failure of primary container and outer shell, release of entire contents (double containment tank)	1.25E-08
(3) Instantaneous failure of primary and secondary container, release of entire contents (full containment tank)	1E-08
Pressurized Storage (Containers) — instantaneous release of entire contents	5E-07
Pressure relief valves — outflow at the maximum rate	2E-05
Process equipment	
(1) Pumps — catastrophic failure	1E-04
(2) Compressors with gasket — catastrophic failure	1E-04
(3) Heat exchanger — instantaneous release of entire contents from plate heat exchanger	5E-05
Transfer equipment — rupture of loading/unloading arm	3E-08
Piping — aboveground	**Annual probability of failure per meter**
(1) Rupture for nominal diameter <75 mm	1E-06
(2) Rupture for 75 mm < nominal diameter < 150 mm	3E-07
(3) Rupture for nominal diameter > 150 mm	1E-07

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2. *Correct units in Table 15.8.4.1 as follows:*

Table 15.8.4.1 Radiant Heat Flux and Thermal Dosage Outside the Plant Boundary

Maximum Heat Flux Level (kW/m^2)	**Maximum Modified Dosage Unit** ($[kW/m^2]^{4/3}s$)	**Consequences**
5.0	500	At least 10 persons would suffer 2nd degree skin burns on at least 10% of their bodies within 30 seconds of exposure to the fire.
5.0	300	At least one person inside the building would suffer 2nd degree skin burns on at least 10% of the body within 30 seconds of exposure to the fire.
32	N/A	Loss of strength of structural steel exposed to the fire to an extent that its primary load-bearing capacity is reduced significantly over the duration of LNG fire being analyzed.

Issue Date: March 7, 2013

Effective Date: March 27, 2013

(Note: For further information on NFPA Codes and Standards, please see http://www.nfpa.org/docinfolist**)**

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Tentative Interim Amendment

NFPA® 59A

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

2013 Edition

Reference: Table 15.8.4.2
TIA 13-2
(SC 14-3-7/TIA Log #1122)

Pursuant to Section 5 of the NFPA *Regulations Governing the Development of NFPA Standards*, the National Fire Protection Association has issued the following Tentative Interim Amendment to NFPA 59A, *Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG),* 2013 edition. The TIA was processed by the Technical Committee on Liquefied Natural Gas, and was issued by the Standards Council on March 3, 2014, with an effective date of March 23, 2014.

A Tentative Interim Amendment is tentative because it has not been processed through the entire standards-making procedures. It is interim because it is effective only between editions of the standard. A TIA automatically becomes a public input of the proponent for the next edition of the standard; as such, it then is subject to all of the procedures of the standards-making process.

1. Revise Table 15.8.4.2 to read as follows:

Table 15.8.4.2 Criteria for Property Damage Due to Radiant Heat from Fires

Exposed structure	Type of construction/occupancy	Threshold damage criteria
Adjacent LNG container	Reinforced concrete	(1) Temperature of no part of the exposed concrete outer surface of the container structure shall exceed 1000°F (540°C) over the duration of the fire. (2) Temperature of steel reinforcements in pre-stressed concrete shall not exceed 570°F (300°C) over the duration of the fire.
Steel structures		Temperature shall not exceed 570°F (300°C) over the duration of the fire.
Wooden structures		Net heat flux into the structure shall not exceed 8115 Btu/hr-ft^2 (26,500 w/m^2) for unpiloted ignition or 4660 Btu/hr-ft^2 (14,700 w/m^2) for piloted ignition.

Issue Date: March 3, 2014

Effective Date: March 23, 2014

(Note: For further information on NFPA Codes and Standards, please see www.nfpa.org/codelist**)**

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Sequence of Events Leading to Issuance of this NFPA Committee Document

Step 1: Call for Proposals

- Proposed new Document or new edition of an existing Document is entered into one of two yearly revision cycles, and a Call for Proposals is published.

Step 2: Report on Proposals (ROP)

- Committee meets to act on Proposals, to develop its own Proposals, and to prepare its Report.
- Committee votes by written ballot on Proposals. If two-thirds approve, Report goes forward. Lacking two-thirds approval, Report returns to Committee.
- Report on Proposals (ROP) is published for public review and comment.

Step 3: Report on Comments (ROC)

- Committee meets to act on Public Comments to develop its own Comments, and to prepare its report.
- Committee votes by written ballot on Comments. If two-thirds approve, Report goes forward. Lacking two-thirds approval, Report returns to Committee.
- Report on Comments (ROC) is published for public review.

Step 4: Technical Report Session

- "*Notices of intent to make a motion*" are filed, are reviewed, and valid motions are certified for presentation at the Technical Report Session. ("Consent Documents" that have no certified motions bypass the Technical Report Session and proceed to the Standards Council for issuance.)
- NFPA membership meets each June at the Annual Meeting Technical Report Session and acts on Technical Committee Reports (ROP and ROC) for Documents with "certified amending motions."
- Committee(s) vote on any amendments to Report approved at NFPA Annual Membership Meeting.

Step 5: Standards Council Issuance

- Notification of intent to file an appeal to the Standards Council on Association action must be filed within 20 days of the NFPA Annual Membership Meeting.
- Standards Council decides, based on all evidence, whether or not to issue Document or to take other action, including hearing any appeals.

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The following classifications apply to Technical Committee members and represent their principal interest in the activity of the committee.

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U *User:* A representative of an entity that is subject to the provisions of the standard or that voluntarily uses the standard.

I/M *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.

L *Labor:* A labor representative or employee concerned with safety in the workplace.

R/T *Applied Research/Testing Laboratory:* A representative of an independent testing laboratory or independent applied research organization that promulgates and/or enforces standards.

E *Enforcing Authority:* A representative of an agency or an organization that promulgates and/or enforces standards.

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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 the *User* classification.

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NOTES:
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