NFPA 59A

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

2001 Edition

NFPA INTERNATIONAL

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NFPA 59A

Standard for the

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

2001 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 the National Fire Protection Association, Inc., at its November Meeting held November 12–15, 2000, in Orlando, FL. It was issued by the Standards Council on January 13, 2001, with an effective date of February 9, 2001, and supersedes all previous editions.

This edition of NFPA 59A was approved as an American National Standard on February 9, 2001.

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 the 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, and 1996.

The 2001 edition was developed in a joint effort of the NFPA LNG Committee and the Canadian Standards Association LNG Committee in an effort to harmonize the requirements of NFPA 59A and CSA Z 276.

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

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

Contents

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

Information on referenced publications can be found in Chapter 12 and Appendix E.

NOTE: All pressures used in this standard are gauge pressure unless otherwise indicated.

Chapter 1 General

1.1* Scope.

1.1.1 This standard shall apply to the following:

(1) Design
(2) Location
(3) Construction
(4) Operation
(5) Maintenance of facilities at any location for the liquefaction of natural gas and the storage, vaporization, transfer, handling, and truck transport of liquefied natural gas (LNG), as well as the personnel training

1.1.2 This standard shall apply to all containers for the storage of LNG, including those with insulation systems applying a vacuum.

1.1.3 This standard shall not apply to frozen ground containers.

1.2 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. Technical documentation shall be submitted to the authority having jurisdiction to demonstrate equivalency. The system, method, or device shall be approved for the intended purpose by the authority having jurisdiction.

1.3 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.

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.

In 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.

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.

1.4 Training of Personnel. Persons engaged in the production, handling, and storage of LNG shall be trained in the hazards and properties of LNG.

1.5 Metric Practices. Metric units in this standard are based upon ASTM E 380, *Standard Practice for the Use of the International System of Units (SI)*. Where clearance distances are to be determined, the conversion from English to metric units shall be calculated to the nearest 0.5 m. Alternate usage of English and metric units on a single project shall not be used to lessen clearance distances.

1.6 Referenced Standards. Reference is made to both United States and Canadian standards, because this standard is prepared for use in both the United States and Canada, as well as in other countries. Where this standard is adopted, the adoption shall include a statement of which U.S. or Canadian reference standards shall be used. If no such statement is made, the user shall use either all available U.S. or all available Canadian reference standards. If other reference standards are to be used, it shall be so stated.

1.7 Definitions.

1.7.1* Approved. Acceptable to the authority having jurisdiction.

1.7.2* Authority Having Jurisdiction. The organization, office, or individual responsible for approving equipment, an installation, or a procedure.

1.7.3 Barrel. A unit of volume. One barrel equals 42 U.S. gal, or 5.615 ft^3 (0.159 m^3).

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

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

1.7.6 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.

1.7.7 Container. A vessel for storing liquefied natural gas.

1.7.7.1 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, is dependent on the freezing of water-saturated earth materials, and has appropriate methods for maintaining its tightness or is impervious by nature.

1.7.7.2 Membrane Container. A container that has a non–self-supporting thin layer (membrane) inner tank that is supported through insulation by an outer tank.

1.7.7.3 Prestressed Concrete Container. A concrete container in which the stresses created by the different loads or loading combinations do not exceed the allowable stresses provided for in this standard.

1.7.8 Deriming (synonymous with defrosting or deicing). The removal by heating and evaporation, sublimation, or solutions of accumulated constituents that form solids, such as water and carbon dioxide, from low-temperature process equipment.

1.7.9 Design Pressure. The pressure used in the design of equipment, a container, or a vessel for the purpose of determining the minimum allowable thickness or physical characteristics of its parts; where applicable, static head is included in the design pressure to determine the thickness of any specific part.

1.7.10 Dike. A structure used to establish an impounding area.

1.7.11 Failsafe. 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.

1.7.12 Fired Equipment. Any equipment in which the combustion of fuels takes place; equipment can include fired boilers, fired heaters, internal combustion engines, certain integral heated vaporizers, the primary heat source for remote heated vaporizers, gas-fired oil foggers, fired regeneration heaters, and flared vent stacks.

1.7.13 Fixed Length Dip Tube. A pipe that has a fixed open end inside a container at a designated elevation that is intended to show a liquid level.

1.7.14 Flame Spread Rating. The flame spread rating of materials as determined in accordance with NFPA 255, *Standard Method of Test of Surface Burning Characteristics of Building Materials,* or ULC Standard CAN4-S102, *Surface Burning Characteristics of Building Materials and Assemblies*, 1988, as appropriate.

1.7.15 G. The normal or standard constant of gravity; at sea level, "G" equals approximately 32.2 ft/sec/sec (9.81 m/sec/sec).

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

1.7.17 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.

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

1.7.19 LNG Plant. A plant whose components are used to store liquefied natural gas and may also condition, liquefy, or vaporize natural gas.

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

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

1.7.22 Operating Company. The individual, partnership, corporation, public agency, or other entity that owns or operates an LNG plant.

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

1.7.24 Process Plant. All systems needed to condition, liquefy, or vaporize natural gas in all areas of application as identified under the scope of this standard.

1.7.25 Shall. Indicates a mandatory requirement.

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

1.7.27 Transfer Area. That portion of an LNG plant containing a piping system where LNG, flammable liquids, or flammable refrigerants are introduced into or removed from the facility, such as truck loading or ship unloading areas, or where piping connections are connected or disconnected routinely. Transfer areas do not include product sampling devices or permanent plant piping.

1.7.28 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.

Chapter 2 Plant Siting and Layout

2.1 Plant Site Provisions.

2.1.1 The following factors shall be considered in the selection of plant site locations.

(a) Provision for minimum clearances as stated in this standard between LNG containers, flammable refrigerant storage tanks, flammable liquid storage tanks, structures and plant equipment, both with respect to plant property lines and each other, shall be considered.

(b) 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 9.

(c) The degree that the plant can, within limits of practicality, be protected against forces of nature shall be considered.

(d) Other factors applicable to the specific site that have a bearing on the safety of plant personnel and the surrounding public shall be considered. The review of such factors shall include an evaluation of potential incidents and safety measures incorporated in the design or operation of the facility.

2.1.2 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.

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

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

2.2 Major Site Provisions for Spill and Leak Control.

2.2.1 General.

2.2.1.1 Provisions shall be made to minimize the possibility of the accidental discharge of LNG at containers from endangering adjoining property or important process equipment and structures or from reaching waterways in accordance with one of the following methods:

(1) An impounding area surrounding the container(s) that is formed by a natural barrier, dike, impounding wall, or combination thereof complying with 2.2.2 and 2.2.3
(2) An impounding area formed by a natural barrier, dike, excavation, impounding wall, or combination thereof complying with 2.2.2 and 2.2.3 plus a natural or man-made drainage system surrounding the container(s) that complies with 2.2.2 and 2.2.3
(3) Where the container is constructed below or partially below the surrounding grade, an impounding area formed by excavation complying with 2.2.2 and 2.2.3

2.2.1.2 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

If impounding areas also are required in order to comply with 2.1.2, such areas shall be in accordance with 2.2.2 and 2.2.3.

2.2.1.3 In certain installations, the provisions of 2.1.2, 2.2.1.1, and 2.2.1.2 that apply to adjoining property or waterways shall be permitted to be waived or altered at the discretion of the authority having jurisdiction 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.

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

2.2.2 Impounding Area and Drainage System Design and Capacity.

2.2.2.1 Impounding areas serving LNG containers shall have a minimum volumetric holding capacity, *V*, 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) For impounding areas serving a single container, *V* equals the total volume of liquid in the container, assuming the container is full.
(2) For impounding areas serving more than one container with provision made to prevent low temperature or fire exposure resulting from leakage from any one container served from causing subsequent leakage from any other container served, *V* equals the total volume of liquid in the largest container served, assuming the container is full.
(3) For impounding areas serving more than one container without provision made in accordance with 2.2.2.1(b), *V* equals the total volume of liquid in all containers served, assuming all containers are full.

2.2.2.2 Impounding areas, if provided to serve only vaporization, process, or LNG transfer areas, shall have a minimum volumetric capacity equal to the greatest volume of LNG, flammable refrigerant, or flammable liquid that can be discharged into the area during a 10-minute period from any single accidental leakage source or during a shorter time period based upon demonstrable surveillance and shutdown provisions acceptable to the authority having jurisdiction.

2.2.2.3 Enclosed drainage channels for LNG shall be prohibited.

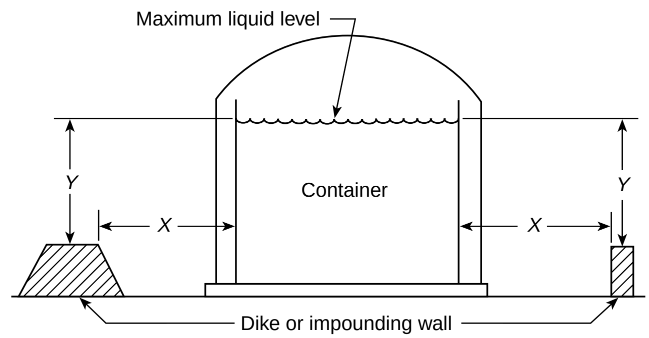
Exception: Container downcomers used to rapidly conduct spilled LNG away from critical areas shall be permitted to be enclosed if they are sized for the anticipated liquid flow and vapor formation rates.

2.2.2.4 Dikes, impounding walls, and drainage systems for LNG and flammable refrigerant containment shall be of compacted earth, concrete, metal, or other materials. They shall be permitted to be independent of the container, or they shall be permitted to be mounded integral to, or constructed against, the container. They, 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. Where the outer shell of a double-wall tank complies with these requirements, it shall be permitted to be considered as the impounding area for purposes of determining the siting area distances in 2.2.3. 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 2.2.1.1 shall be provided.

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

2.2.2.6 The dike or impounding wall height and distance from containers operating at 15 psi (100 kPa) or less shall be determined in accordance with Figure 2.2.2.6.

FIGURE 2.2.2.6 Dike or impoundment wall proximity to containers.



Notes:
- Dimension *X* shall equal or exceed the sum of dimension *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 may have any value.
- Dimension *X* is the distance from the inner wall of the container to the closest face of the dike or impounding wall.
- Dimension *Y* is the distance from the maximum liquid level in the container to the top of the dike or impounding wall.

2.2.2.7 Provision shall be made to clear rain or other water from the impounding area. Automatically controlled sump pumps shall be permitted if equipped with an automatic cutoff device that prevents their operation when exposed to LNG temperatures. Piping, valves, and fittings whose failure could allow liquid to escape from the impounding area shall be capable of withstanding continuous exposure to LNG temperatures. If gravity drainage is employed for water removal, provision shall be made to prevent the escape of LNG by way of the drainage system.

2.2.2.8 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 is a problem, mitigating measures shall be provided.

2.2.3 Impounding Area Siting.

2.2.3.1 The provisions of 2.2.3 shall not apply to impounding areas serving only transfer areas at the water's edge of marine terminals.

2.2.3.2 Provisions shall be made as follows to minimize the possibility of the damaging effects of fire reaching beyond a property line that can be built upon and that would result in a distinct hazard:

(a) Provisions shall be made to prevent thermal radiation flux from a fire from exceeding the following limits when atmospheric conditions are 0 (zero) windspeed, 70°F (21°C) temperature, and 50 percent relative humidity.

(1) 1600 Btu/hr/ft^2 (5000 W/m^2) at a property line that can be built upon for ignition of a design spill (as specified in 2.2.3.5)
(2) 1600 Btu/hr/ft^2 (5000 W/m^2) at the nearest point located outside the owner's property line that, at the time of plant siting, is used for outdoor assembly by groups of 50 or more persons for a fire over an impounding area containing a volume, *V*, of LNG determined in accordance with 2.2.2.1
(3) 3000 Btu/hr/ft^2 (9000 W/m^2) at the nearest point of the building or structure outside the owner's property line that is in existence at the time of plant siting and used for occupancies classified by NFPA *101*®, *Life Safety Code*®, as assembly, educational, health care, detention and correction or residential for a fire over an impounding area containing a volume, *V*, of LNG determined in accordance with 2.2.2.1
(4) 10,000 Btu/hr/ft^2 (30,000 W/m^2) at a property line that can be built upon for a fire over an impounding area containing a volume, *V*, of LNG determined in accordance with 2.2.2.1

(b) Thermal radiation distances shall be calculated in accordance with the following:

(1) The model described in Gas Research Institute report GRI 0176, "LNGFIRE: A Thermal Radiation Model for LNG Fires"

Exception: Distances shall be permitted to be calculated using models that meet the following criteria:

(a) Take into account impoundment configuration, wind speed and direction, humidity, and atmospheric temperature

(b) Have been validated by experimental test data appropriate for the size and conditions of the hazard to be evaluated

(c) Are acceptable to the authority having jurisdiction

(2) If the ratio of the major and minor dimensions of the impoundment does not exceed 2, the following formula, which shall be permitted to be used:

$$d = F\sqrt{A}$$

where:

d = distance, in ft (m), from the edge of impounded LNG
A = surface area, in ft^2 (m^2), of impounded LNG
F = flux correlation factor equal to the following:
3.0 for 1600 Btu/(hr · ft^2)
2.0 for 3000 Btu/(hr · ft^2)
0.8 for 10,000 Btu/(hr · ft^2)

2.2.3.3 The spacing of an LNG tank impoundment to the property line that can be built upon shall be such that, in the event of an LNG spill specified in 2.2.3.5, an average 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 calculations using one of the following:

(a) The model described in Gas Research Institute report GRI 0242, "LNG Vapor Dispersion Prediction with the DEGADIS Dense Gas Dispersion Model"

(b) The model described in Gas Research Institute report GRI-96/0396.5, "Evaluation of Mitigation Models for Accidental LNG Releases, Volume 5; Using FEM3A for LNG Accidental Consequence Analysis"

(c) A model that incorporates the following:

(1) Takes into account physical factors influencing LNG vapor dispersion, including, but not limited to, gravity spreading, heat transfer, humidity, wind speed and direction, atmospheric stability, buoyancy, and surface roughness
(2) Has been validated by experimental test data appropriate for the size and conditions of the hazard to be evaluated
(3) Is acceptable to the authority having jurisdiction

The computed distances shall include calculations based on one of the following:

(1) 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
(2) The Pasquill–Gifford atmospheric stability, Category F, with a 4.5-mph (2-m/sec) wind speed

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).

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.

2.2.3.4 Provisions shall be made to minimize the possibility of a flammable mixture of vapors from a design spill specified in 2.2.3.5, as appropriate, reaching a property line that can be built upon and that would result in a distinct hazard. Flammable mixture dispersion distances shall be determined in accordance with the following:

(a) Flammable mixture dispersion distances shall be calculated in accordance with the model described in Gas Research Institute report GRI 0242, "LNG Vapor Dispersion Prediction with the DEGADIS Dense Gas Dispersion Model."

Exception: Distances shall be permitted to be calculated using models that meet the following criteria:

(a) Take into account physical factors influencing LNG vapor dispersion, including gravity spreading, heat transfer, humidity, wind speed and direction, atmospheric stability, buoyancy, and surface roughness

(b) Have been validated by experimental test data appropriate for the size and conditions of the hazard to be evaluated

(c) Are acceptable to the authority having jurisdiction

(b) The computed distances shall include calculations based on one of the following:

(1) 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
(2) The Pasquill–Gifford atmospheric stability, Category F, with a 4.5-mph (2-m/sec) wind speed

(c) 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).

(d) 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.

2.2.3.5 The design spill shall be determined in accordance with Table 2.2.3.5.

2.2.3.6 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.

2.2.3.7 Containers with an aggregate storage of 70,000 gal (265 m^3) or less on one site shall be permitted to be installed in accordance with Table 2.2.4.1 where the containers are equipped with the following:

(a) All connections shall be equipped with automatic failsafe valves. These automatic valves shall be 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

(3) Gas detection

(4) Manual operation from a local and remote location

Exception No. 1: Relief valves and instrument connection valves shall not apply.

Exception No. 2: Connections used only for flow into the container shall be permitted to be equipped with two backflow check valves in lieu of the requirements in 2.2.3.7(a).

(b) 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. The type, quantity, and location of the detection devices shall be in accordance with the requirements of Chapter 9.

2.2.3.8 In no case shall the distance from the nearest edge of impounded liquid to a property line that can be built upon, or the near edge of a navigable waterway as defined by federal regulations, be less than 50 ft (15 m).

2.2.4 Container Spacing.

2.2.4.1 The minimum separation distance between LNG containers or tanks containing flammable refrigerants and exposures shall be in accordance with Table 2.2.4.1.

Exception: With the approval of the authority having jurisdiction, such equipment shall be permitted to be located a shorter distance from buildings or walls constructed of concrete or masonry but at least 10 ft (3.0 m) from any building openings.

Table 2.2.3.5 Design Spill

Container Penetration	Design Spill	Design Spill Duration
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. Use the container with the largest flow if more than one container in the impounding area.	Use the formula $q = \frac{4}{3} d^2 \sqrt{h}$ until the differential head acting on the opening is 0 (zero). For SI Units: $q = \frac{1.06}{10,000} d^2 \sqrt{h}$
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: (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.
Containers with penetrations below the liquid level with internal shutoff valves in accordance with 6.3.3.3.	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 formula $q = \frac{4}{3} d^2 \sqrt{h}$ for 1 hour. For SI Units: $q = \frac{1.06}{10,000} d^2 \sqrt{h}$
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 is the flow rate [ft^3/min (m^3/min)] of liquid. d is the diameter [in. (mm)] of tank penetration below the liquid level. h is the height [ft (m)] of liquid above penetration in the container when the container is full.

Table 2.2.4.1 Distances from Impoundment Areas to Buildings and Property Lines

Container Water Capacity		Minimum Distance from Edge of Impoundment or Container Drainage System to Buildings and Property Lines		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
2,001–15,000	7.6–56.8	25	7.6	5	1.5
15,001–30,000	56.8–114	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)		$^1/_4$ of the sum of the diameters of adjacent containers [5 ft (1.5 m) minimum]	

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

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

2.2.5 Vaporizer Spacing. See Chapter 5 for vaporizer classification.

2.2.5.1 Unless the intermediate heat transfer fluid is nonflammable, vaporizers and their primary heat sources shall be located at least 50 ft (15 m) from any other source of ignition. In multiple vaporizer installations, an adjacent vaporizer or primary heat source shall not be considered to be a source of ignition.

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 is either cooled down or being cooled down.

2.2.5.2 Integral heated vaporizers shall be located at least 100 ft (30 m) from a property line that can be built upon *(see 2.2.5.4)* and at least 50 ft (15 m) from the following:

(1) Any impounded LNG, flammable refrigerant, or flammable liquid *(see 2.2.4)*, 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

Exception: Vaporizers used in conjunction with LNG containers having a capacity of 70,000 gal (265 m^3) or less in accordance with the exception to 2.2.5.4.

2.2.5.3 Heaters or heat sources of remote heated vaporizers shall comply with 2.2.5.2.

Exception: If the intermediate heat transfer liquid is nonflammable, the property line clearance and 2.2.5.2(3) shall not apply.

2.2.5.4 Remote heated, ambient, and process vaporizers shall be located at least 100 ft (30 m) from a property line that can be built upon. Remote heated and ambient vaporizers shall be permitted to be located within an impounding area.

Exception: 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 2.2.4.1, assuming the vaporizer to be a container with a capacity equal to the largest container to which it is connected.

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

2.2.6 Process Equipment Spacing.

2.2.6.1 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 rooms, offices, shops, and other occupied structures.

Exception: Control rooms shall be permitted to be located in a building housing flammable gas compressors where the building construction complies with 2.3.1.

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

2.2.7 Loading and Unloading Facility Spacing.

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

2.2.7.2 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.

Exception: This requirement shall not apply to structures or equipment directly associated with the transfer operation.

2.3 Buildings and Structures.

2.3.1 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.

2.3.2 If rooms containing LNG and flammable fluids are located within or attached to buildings in which such fluids are not handled (e.g., control rooms, 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.

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 4.3.3.2 to 4.3.3.4.

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

2.3.2.2 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.

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

2.3.3 Buildings or structural enclosures not covered by Section 2.3 and 2.3.2 shall be located, or provision otherwise shall be made, to minimize the possibility of entry of flammable gases or vapors. *(See 9.4.1.)*

2.3.4 The temporary use of LNG portable equipment for peak-shaving applications or for service maintenance during gas systems repair or alteration or for other short-term applications shall be permitted where the following requirements are met:

(a) LNG transport vehicles complying with DOT requirements *(see 8.5.1.1)* shall be used as the supply container.

(b) All portable LNG equipment shall be operated by at least one person qualified by experience and training in the safe operation of these systems. All other operating personnel, at a minimum, shall be qualified by training.

(c) 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.

(d) 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. Portable or temporary containment means shall be permitted to be used.

(e) Vaporizer controls shall comply with 5.3.1, 5.3.2, and Section 5.4. Each heated vaporizer shall be provided with a means to shut off the fuel source remotely. The device also shall be operable at the installed location.

(f) Equipment and operations shall comply with 11.4.5(b), 11.4.5.2(b), Section 8.7, 8.8.1, 9.1.2, 9.2.1, 9.2.2, 9.2.3, and 2.3.4(c). Clearance distance provisions shall not apply.

(g) The LNG facility spacing specified in Table 2.2.4.1 shall be maintained, except where necessary to provide temporary service on a public right-of-way or on property where clearances specified in Table 2.2.4.1 are not feasible and the following additional requirements are met:

(1) Traffic barriers shall be erected on all sides of the facility subject to passing vehicular traffic.
(2) The operation shall be continuously attended to monitor the operation whenever LNG is present at the facility.
(3) If the facility or the operation causes any restriction to the normal flow of vehicular traffic, in addition to the monitoring personnel required in 2.3.4(g)(2), flag persons shall be continuously on duty to direct such traffic.

(h) Reasonable provision shall be made to minimize the possibility of accidental ignition in the event of a leak.

(i) Portable or wheeled fire extinguishers recommended by their manufacturer for gas fires shall be available at strategic locations. These extinguishers shall be provided and maintained in accordance with NFPA 10, *Standard for Portable Fire Extinguishers*.

(j) The site shall be continuously attended and provisions shall be made to restrict public access to the site whenever LNG is present.

2.3.5 If odorization is required of the emergency facility, the restrictions of 2.2.4.1 shall not apply to the location of odorizing equipment containing 20 gal (7.6 L) of flammable odorant or less within the retention system.

2.4 Designer and Fabricator Competence.

2.4.1 Designers and fabricators of LNG facilities shall have competence in the design or fabrication of LNG containers, process equipment, refrigerant storage and handling equipment, loading and unloading facilities, fire protection equipment, and other components of the facility.

2.4.2 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.

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

2.4.4 Designers, fabricators, and constructors of LNG facility equipment shall be competent in the design, fabrication, and construction of LNG containers, cryogenic equipment, piping systems, fire protection equipment, and other components of the facility. Supervision shall be provided for the fabrication, construction, and acceptance tests of facility components to the extent necessary to ensure that the facilities are structurally sound and otherwise in compliance with this standard.

2.5* Soil Protection for Cryogenic Equipment. LNG containers *(see 4.1.7)*, cold boxes, piping and pipe supports, and other cryogenic apparatus shall be designed and constructed properly 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.

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

2.7 Concrete Materials.

2.7.1 Concrete used for construction of LNG containers shall be in accordance with Section 4.3.

2.7.2 Concrete structures that are normally or periodically in contact with LNG shall be designed to withstand the design load, applicable environmental loadings, and anticipated temperature effects. Such structures shall include, but shall not be limited to, foundations for cryogenic equipment. They shall comply with the following:

(a) The design of the structures shall be in accordance with the provisions of 4.3.2.

(b) The materials and construction shall be in accordance with the provisions of 4.3.3.

2.7.3 Pipe supports shall comply with Section 6.4.

2.7.4 All other concrete structures shall be investigated for the effects of potential contact with LNG. 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 2.7.2(a) or (b).

2.7.5 Concrete for incidental nonstructural uses, such as slope protection and impounding area paving, shall conform to ACI 304R, *Guide for Measuring, Mixing, Transportation and Placing of Concrete*. Reinforcement shall be a minimum of 0.5 percent of the cross-sectional area of concrete for crack control in accordance with 2.2.1 of ACI 344R-W, *Design and Construction of Circular Wire and Strand Wrapped Prestressed Concrete Structures*.

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

Chapter 3 Process Equipment

3.1 General. 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 fire fighting, and to facilitate dispersal of accidentally released liquids and gases
(2) Indoors, in enclosing structures complying with Section 2.3 and 2.3.2

3.2 General. Process system equipment containing LNG, flammable refrigerants, or flammable gases shall be in accordance with one of the following:

(1) Outdoors, for ease of operation, to facilitate manual fire fighting, and to facilitate dispersal of accidentally released liquids and gases
(2) Indoors, in enclosing structures complying with 2.3.2 and 2.3.3

3.2.1 Pumps and compressors shall be constructed of materials suitable for the temperature and pressure conditions that might be considered.

3.2.2 Valving shall be installed so that each pump or compressor can be isolated for maintenance. Where pumps or centrifugal compressors are installed for operation in parallel, each discharge line shall be equipped with a check valve.

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

3.2.4 Each pump shall be provided with an adequate vent, relief valve, or both, that will prevent over-pressuring the pump case during the maximum possible rate of cooldown.

3.3 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 2.2 of this standard.

3.4 Process Equipment.

3.4.1 Process equipment shall be sited in accordance with Section 2.2.

3.4.2 Boilers shall be designed and fabricated in accordance with the ASME *Boiler and Pressure Vessel Code*, Section I, or CSA Standard B 51, *Boiler, Pressure Vessel and Pressure Piping Code*, and 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 CSA Standard B 51, *Boiler, Pressure Vessel and Pressure Piping Code*, and shall be code-stamped.

3.4.3 Shell and tube heat exchangers shall be designed and fabricated in accordance with the standards of the Tubular Exchanger Manufacturers Association (TEMA). The shells and internals of all exchangers shall be pressure tested, inspected, and stamped in accordance with the ASME *Boiler Pressure Vessel Code*, Section VIII, Division 1 or Division 2, or CSA B51, where such components fall within the jurisdiction of the pressure vessel code.

3.4.4* 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*.

3.4.5 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. Boil-off and flash gases shall discharge safely into the atmosphere or into a closed system. The boil-off venting system shall be designed so that it cannot normally inspirate air during operation.

3.4.6 If internal vacuum conditions can occur in any piping, process vessels, cold boxes, or other equipment, the facilities subject to vacuum shall be designed to withstand the vacuum conditions or provision shall be made to prevent the development of a vacuum in the equipment that might create a hazardous condition. If gas is introduced to obviate this problem, it shall be of such composition or so introduced that it does not create a flammable mixture within the system.

Chapter 4 Stationary LNG Storage Containers

4.1 General.

4.1.1 Inspection. Prior to initial operation, containers shall be inspected to ensure compliance with the engineering design and material, fabrication, assembly, and test provisions of this standard. The operator shall be responsible for this inspection. The performance of any part of the inspection shall be permitted to be delegated to inspectors who are employees of the operator's own organization, an engineering or scientific organization, or a recognized insurance or inspection company. Inspectors shall be qualified in accordance with the code or standard applicable to the container and as specified in this standard.

Exception: ASME containers.

4.1.2 Basic Design Considerations.

4.1.2.1 The operator shall specify (1) the maximum allowable working pressure, which includes a margin above the normal operating pressure, and (2) the maximum allowable vacuum.

4.1.2.2 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 −29°C (−20°F)] shall be physically and chemically compatible with LNG and intended for service at −168°C (−270°F).

4.1.2.3 All piping that is a part of an LNG container shall be in accordance with Chapter 6. This container piping shall include all piping internal to the container, within insulation spaces, within void spaces, and external piping attached or connected to the container up to the first circumferential external joint of the piping. Inert gas purge systems wholly within the insulation spaces are exempt from this provision. In the case of ASME containers, all piping that is a part of an 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 ASME B 31.3, *Process Piping*. Compliance with this requirement 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."

4.1.2.4 All LNG containers shall be designed to accommodate both top and bottom filling unless other positive means are provided to prevent stratification. *(See 11.3.7.)*

4.1.2.5 Any portion of the outer surface area of an LNG container that accidentally could be exposed to low temperatures resulting from the leakage of LNG or cold vapor from flanges, valves, seals, or other nonwelded connections shall be intended for such temperatures or otherwise protected from the effects of such exposure.

4.1.2.6 Where two or more containers are sited in a common dike, the container foundations shall be capable of withstanding contact with LNG or shall be protected against contact with an accumulation of LNG that might endanger structural integrity.

4.1.2.7 The density of the liquid shall be assumed to be the actual mass per unit volume at the minimum storage temperatures, except that in no case shall the density assumed be less than 470 kg/m^3 (29.3 lb/ft^3).

4.1.2.8 Provisions shall be made for removal of the container from service.

4.1.3 Seismic Design.

4.1.3.1 Seismic loads shall be considered in the design of the LNG container and its impoundment system. For all installations, except those provided for in 4.1.3.8, the operator shall perform a site-specific investigation to determine the characteristics of seismic ground motion and associated response spectra. This site-specific investigation 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, rear source effects, if any, and the characteristics of subsurface conditions.

On the basis of this investigation, the ground motion of a probabilistic maximum considered earthquake (MCE) shall be the motion having a 2 percent probability of exceedance within a 50-year period (mean recurrence interval of 2475 years), subject to the exception in 4.1.3.1(a). Using this MCE ground motion vertical and horizontal acceleration response, spectra shall be constructed covering the entire range of anticipated damping factors and natural periods of vibration, including the damping factor and first-mode sloshing period of vibration of the contained LNG. The MCE spectral response acceleration for any period, *T*, shall be taken from the selected design spectrum with a damping that best represents the structure being investigated.

The ordinates of the vertical response spectrum shall not be less than $^2/_3$ of those of the horizontal spectrum.

(a) Where the probabilistic spectral response ordinates for a 5 percent damped response spectrum having a 2 percent probability of exceedance within a 50-year period at periods of 0.2 second or 1 second exceed the corresponding ordinates of the deterministic limit of 4.1.3.1(c), the MCE ground motion shall be taken as the lesser of the following:

(1) The probabilistic MCE ground motion as defined in 4.1.3.1
(2) The deterministic ground motion of 4.1.3.1(b), but shall not be less than the deterministic limit ground motion of 4.1.3.1(c)

(b) The deterministic MCE ground motion response spectrum shall be calculated at 50 percent of the median 5 percent damped spectral response acceleration at all periods resulting from a characteristic earthquake on a known active fault within the region.

(c) The deterministic limit on MCE ground motion shall be taken as the response spectrum determined in accordance with the provisions of the *NEHRP Recommended Provisions for Seismic Regulation for New Buildings and Other Structures* (FEMA), using an importance factor, *I*, of 1.0, with the value of *Ss* (mapped MCE spectral response acceleration at short periods) taken as 1.5g, and the value of *S*1 (mapped MCE spectral response acceleration at 1 second) taken as 0.6g, for the site class most representative of the site conditions where the LNG facility is located.

4.1.3.2 The LNG container and its impounding system shall be designed for two levels of seismic ground motion, the operating basis earthquake (OBE) and the safe shutdown earthquake (SSE) defined as follows.

(a) The OBE shall be represented by a ground motion response spectrum in which the spectral acceleration at any period *T* shall be equal to $^2/_3$ of the spectral acceleration of the MCE ground motion defined in 4.1.3.1. The 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.

(b) The SSE ground motion shall be the motion represented by a 5 percent damped acceleration response spectrum having a 1 percent probability of exceedance within a 50-year period (mean return interval of 4975 years). However, the spectral acceleration of the SSE response spectrum shall not exceed twice the corresponding OBE spectral accelerations.

4.1.3.3 The two levels of ground motion defined in 4.1.3.2 shall be used for the earthquake-resistant design of the following structures and systems:

(1) An LNG container and its impounding system

(2) System components required to isolate the LNG container 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 4.1.3.3(1) or (2)

4.1.3.4 The structures and systems identified in 4.1.3.3(1), (2), and (3) shall be designed to remain operable during and after an OBE. The design shall provide for no loss of containment capability of the primary container, and it shall be possible to isolate and maintain the LNG container during and after the SSE.

4.1.3.5 The impounding system shall, as a minimum, be designed to withstand an SSE while empty and an OBE while holding the volume, *V*, as specified in 2.2.2.1. After an OBE or an SSE, there shall be no loss of containment capability.

4.1.3.6 An LNG container shall be designed for the OBE, and a stress-limit check shall be made for the SSE to ensure compliance with 4.1.3.4. OBE and SSE analyses shall include the effect of liquid pressure on buckling stability. Stresses for the OBE shall be in accordance with the document referenced in Sections 4.2, 4.3, or 6.1, as applicable. Stresses for the SSE shall be subjected to the following limits:

(a) In metal containers, stresses shall be allowed to reach the specified minimum yield for the tensile conditions and critical buckling for the compression condition.

(b) In prestressed concrete containers, axial hoop stresses from unfactored loads shall not exceed the modulus of rupture for the tensile condition and 60 percent of the specified 28-day compressive strength for the compressive condition. Extreme fiber stresses from combined axial and bending hoop forces from unfactored loads shall not exceed the modulus of rupture for the tensile condition and 69 percent of the specified 28-day compressive strength for the compressive condition. Hoop tensile stresses shall not exceed the yield stress in non-prestressed reinforcement and 94 percent of the yield stress in prestressed reinforcement with the assumption of a cracked section.

(c) After an SSE event, the container shall be emptied and inspected prior to resumption of container-filling operations.

4.1.3.7 The design of the LNG container and associated structural components shall incorporate a dynamic analysis that includes the effects of sloshing and restrained liquid. Container flexibility, including shear deformation, shall be included in the determination of the container response. For a container not founded on bedrock, soil–structure interaction shall be included. Where the container is supported by pile caps, the flexibility of the pile system shall be considered in the analysis.

4.1.3.8 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:

Horizontal force:

$$V = Z_c \times W$$

where:

Z_c = the seismic coefficient equal to 0.60 SDS

SDS = the maximum design spectral acceleration determined in accordance with the structures provisions of the *NEHRP Recommended Provisions for Seismic Regulation for New Buildings and Other Structures*, (FEMA), using an importance factor, *I*, of 1.0, for the site class most representative of the site conditions where the LNG facility is located

W = the total weight of the container and its contents

Design vertical force:

$$P = {}^{2}/_{3} \times Z_c \times W$$

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. For periods of vibration greater than 0.06 second, the method of design in 4.1.3.1 through 4.1.3.5 shall be followed.

4.1.3.9 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.

4.1.3.10 The requirements of this subsection shall apply to ASME containers built prior to July 1, 1996, when reinstalled.

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

4.1.4 Wind and Snow Loads. The wind and snow loads for the design of LNG storage containers shall be determined using the procedures outlined in ASCE 7, *Minimum Design Loads for Buildings and Other Structures*. Where a probabilistic approach is used, a 100-year mean occurrence interval shall be used.

In Canada: The wind and snow loads for the design of LNG storage containers shall be determined using the procedure outlined in the *National Building Code of Canada*. For wind, the value in the *National Building Code* for a 100-year mean recurrence interval shall be used.

4.1.5 Container Insulation.

4.1.5.1 Any 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. Where an outer shell is used to retain loose insulation, the shell shall be constructed of steel or concrete. Exposed weatherproofing shall have a flame spread rating not greater than 25. *(See 1.7.14, Flame Spread Rating.)*

4.1.5.2 The space between the inner tank and the outer tank shall contain insulation that is compatible with LNG and natural gas and that is noncombustible. The insulation shall be such that a fire external to the outer tank cannot cause significant deterioration to the insulation thermal conductivity by means such as melting or settling. The load-bearing bottom insulation shall be designed and installed in such a manner that cracking from thermal and mechanical stresses does not jeopardize the integrity of the container.

Exception: Materials used between the inner and outer tank bottoms (floors) only shall not be required to meet the combustibility requirements, provided the material and the design of the installation comply with all of the following:

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

(b) 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 rating not greater than 25 and shall not support continued progressive combustion.

(c) 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.

(d) The materials, in the installed condition, shall be demonstrated to be capable of being purged of natural gas. The natural gas remaining after purging shall not be significant and shall not increase the combustibility of the material.

4.1.6 Filling Volume. Containers designed to operate at a pressure in excess of 15 psi (100 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.

4.1.7 Foundations.

4.1.7.1* LNG containers shall be installed on foundations designed by a qualified engineer and constructed in accordance with recognized structural engineering practices. Prior to the start of design and construction of the foundation, a subsurface investigation shall be conducted by a qualified soils engineer to determine the stratigraphy and physical properties of the soils underlying the site.

4.1.7.2 The bottom of the outer tank shall be above the groundwater table or otherwise protected from contact with groundwater at all times. The outer tank bottom material in contact with soil shall be one of the following:

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

4.1.7.3 Where an outer tank is in contact with the soil, a heating system shall be provided to prevent the 32°F (0°C) isotherm from penetrating the soil. The heating system shall be designed to allow functional and performance monitoring, which shall be done, at a minimum, on a weekly basis. Where there is a discontinuity in the foundation, such as for bottom piping, careful attention and separate treatment shall be given to the heating system in this zone. Heating systems shall be installed so that any heating element or temperature sensor used for control can be replaced. Provisions shall be incorporated to protect against the detrimental effects of moisture accumulation in the conduit, which could result in galvanic corrosion or other forms of deterioration within the conduit or heating element.

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

4.1.7.5 A tank 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 tank foundation heating system (if provided) shall be installed. This system shall be used to conduct a tank bottom temperature survey 6 months after the tank has been placed in service and annually thereafter, after an operating basis earthquake and after the indication of an abnormally cool area.

4.1.7.6 The LNG container foundation shall be monitored periodically for settlement during the life of the facility, including during construction, hydrostatic testing, commissioning, and operation. Any settlement in excess of that anticipated in the design shall be investigated and corrective action taken as required.

4.2 Metal Containers.

4.2.1 Containers Designed for Operation at 15 psi (100 kPa) and Less. Welded containers designed for not more than 15 psi (100 kPa) shall comply with API 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks.* API 620, Appendix Q, shall be applicable for LNG with the following changes:

(a) In Q-7.6.5, “twenty-five percent” shall be changed to “all.”

(b) In Q-7.6.1 through Q-7.6.4, 100 percent radiographic inspection of all vertical and horizontal butt welds associated with the container wall shall be required.

Exception: The shell-to-bottom welds associated with a flat bottom container are exempt from this radiographic inspection requirement.

(c) API 620, Appendix C, C.11, shall be a mandatory requirement.

4.2.2 Containers Designed for Operation at More Than 15 psi (100 kPa).

4.2.2.1 Containers shall be double-walled, with the inner tank holding the LNG surrounded by insulation contained within the outer tank. The insulation shall be evacuated or purged.

4.2.2.2 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) In the case of vacuum insulation, the design pressure shall be the sum of the required working pressure, 101 kPa (14.7 psi) for vacuum allowance, and the hydrostatic head of LNG. In the case of nonvacuum insulation, the design pressure shall be the sum of the required working pressure and the hydrostatic head of LNG.

(b) The inner tank 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 tank expands after an in-service period, the purging and operating pressure of the space between the inner and outer tanks, and seismic loads.

4.2.2.3 The outer tank shall be of welded construction.

(a) Any of the carbon steels in Section VIII, Part UCS of the ASME *Boiler and Pressure Vessel Code* shall be permitted to be used 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.

Exception: Materials with a melting point below 2000°F (1093°C) where the container is buried or mounded.

(b) 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, -29, -30, and -33, using an external pressure of not less than 15 psi (100 kPa)
(2) Paragraph 3.6.2 of CGA 341, *Standard for Insulated Cargo Tank Specification for Cryogenic Liquids*

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, -29, -30, and -33, using an external pressure of 15 psi (100 kPa).

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

(d) The outer tank shall be equipped with a relief device or other device to release internal pressure. The discharge area shall be at least 0.00024 in.^{2}/lb (0.0034 cm^2/kg) of the water capacity of the inner tank, but the area shall not exceed 300 in.^{2} (2000 cm^2). Such a 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 less.

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

(f) Saddles and legs shall be designed in accordance with recognized structural engineering practices. Consideration shall be given to shipping loads, erection loads, seismic loads, wind loads, and thermal loads.

(g) Foundations and supports shall be protected to have a fire-resistance rating of not less than 2 hours. If insulation is used to achieve this requirement, it shall be resistant to dislodgement by fire hose streams.

4.2.2.4 Stress concentrations from the support system shall be minimized by the use of such items as pads and load rings. Consideration shall be given to the expansion and contraction of the inner tank, and the support system shall be designed so that the resulting stresses imparted to the inner and outer tanks are within allowable limits.

4.2.2.5 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. Bellows shall not be permitted within the insulation space.

Piping shall be of materials satisfactory for −278°F (−168°C) as determined by the ASME *Boiler and Pressure Vessel Code*. No liquid line external to the outer tank shall be of aluminum, copper, or copper alloy, unless it is protected against a 2-hour fire exposure. Transition joints shall not be prohibited.

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

(a) For shipping load, the supports shall be designed for the maximum number of G (gravitational acceleration) to be encountered, multiplied by the empty mass of the inner tank.

(b) For operating load, the supports shall be designed for the total mass of the inner tank plus the maximum loading. Appropriate seismic factors shall be included. 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 at least 470 kg/m^3 (29.3 lb/ft^3).

4.2.2.7 The allowable design stress in support members shall be the lesser of $^1/_3$ of the specified minimum tensile strength or $^5/_8$ of the specified minimum yield strength at room temperature. For threaded members, the minimum area at the root of the threads shall be used.

4.3 Concrete Containers.

4.3.1 Scope. This section shall apply to the design and construction of prestressed concrete containers for any operating pressure, whether externally or internally insulated, and for prestressed concrete protective walls surrounding any type of container.

4.3.2 Container Structure.

4.3.2.1 The design of concrete containers shall be in accordance with 4.3.2.2 through 4.3.2.5 and shall comply with standards ACI 318, *Building Code Requirements for Reinforced Concrete*, or CSA Standard CAN 3-A23.3, *Design of Concrete Structures*.

4.3.2.2 Allowable stresses for normal design considerations shall be based on room temperature specified minimum strength values.

4.3.2.3 Tensile stresses (exclusive of direct temperature and shrinkage effects) in carbon steel reinforcing bars when exposed to LNG temperatures under design conditions shall be limited to the allowable stresses listed in Table 4.3.2.3.

Table 4.3.2.3 Allowable Stress of Rebar

Bar Description No.	Maximum Allowable Stresses	
	psi	MPa
ASTM A 615 (USA)		
#4 and smaller	12,000	82.7
#5, #6, and #7	10,000	68.9
#8 and larger	8,000	55.2
CSA G30.18 (Canada)		
#10 and smaller	12,000	82.7
#15, 20	10,000	68.9
#25 and larger	8,000	55.2

4.3.2.4 Steel wire or strands, as specified in 4.3.3.4 and used as unstressed reinforcement, shall be designed with a maximum allowable stress as follows:

(1) Crack control applications — 30,000 psi (207 MPa)
(2) Other applications — 80,000 psi (552 MPa)

4.3.2.5 External forces imposed on the container by backfill restraint during warm-up shall be considered.

4.3.3 Materials Subject to LNG Temperature.

4.3.3.1 Concrete shall be in accordance with the requirements of the following standards:

(1) (USA): ACI 304R, *Guide for Measuring, Mixing, Transportation and Placing of Concrete*, and ACI 318, *Building Code Requirements for Reinforced Concrete*
(2) (CANADA): CAN/CSA A23.1, *Concrete Materials and Methods of Concrete Construction*, CAN 3-A23.3, *Design of Concrete*

Structures, and CAN 3-A23.4, *Precast Concrete — Materials and Construction/Qualification Code for Architectural and Structural Precast Concrete Products*

Tests on concrete shall be carried out for the compressive strength and for the coefficient of contraction of the concrete at the projected low temperature, unless prior test data on these properties are available.

4.3.3.2 Aggregate shall be specified by ASTM C 33, *Standard Specification for Concrete Aggregates* (USA), or CSA Standard CAN/CSA A23.1, *Concrete Materials and Methods of Concrete Construction* (CANADA). Aggregate shall be dense and physically and chemically sound to provide a high strength and durable concrete.

4.3.3.3 Pneumatic mortar shall be in accordance with ACI Standard 506.2, *Specification for Materials, Proportioning, and Application of Shotcrete.*

4.3.3.4 High tensile strength elements for prestressed concrete shall meet the requirements of the following standards:

(1) (USA): ASTM A 416, *Standard Specification for Steel Strand, Uncoated Seven-Wire for Prestressed Concrete*; ASTM A 421, *Standard Specification for Uncoated Stressed-Relieved Steel Wire for Prestressed Concrete*; ASTM A 722, *Standard Specification for Uncoated High-Strength Steel Bar for Prestressing Concrete;* or ASTM A 821, *Standard Specification for Steel Wire, Hand Drawn for Prestressing Concrete Tanks*
(2) (CANADA): CSA Standard G279, *Steel for Prestressed Concrete Tendons* (1998)

In addition, any materials acceptable for service at LNG temperature, such as those materials specified for primary components in API 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*, Appendix Q, or any material shown by test to be acceptable for LNG service, shall be used. Material for permanent end anchorages shall maintain its structural capability at LNG temperatures.

4.3.3.5 Reinforcing steel for reinforced concrete shall be as specified by ACI 318, *Building Code Requirements for Reinforced Concrete.*

Exception: Use of ASTM A 996, Standard Specification for Rail-Steel and Axle-Steel Deformed Bars for Concrete Reinforcement, materials is not permitted.

In Canada: Reinforcing steel for reinforced concrete shall conform to one or more of the following CSA standards: G30.3, *Cold-Drawn Steel Wire for Concrete Reinforcement*; G30.5, *Welded Steel Wire Fabric for Concrete Reinforcement*; and CAN/CSA G30.18, *Billet-Steel Bars for Concrete Reinforcement.*

4.3.3.6 Nonstructural metallic barriers incorporated in, and functioning compositely with, prestressed concrete in direct contact with LNG during normal operations shall be of a metal classified for either "primary components" or "secondary components" in API Standard 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*, Appendix Q, if the composite section is prestressed such that no significant tensile stresses are developed under any design loading condition.

4.3.3.7 Nonstructural metallic barriers incorporated in, and functioning compositely with, prestressed concrete serving primarily as moisture barriers for internally insulated tanks shall be of a metal classified for either "primary component," or "secondary component," service in API Standard 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*, Appendix Q, or of steel conforming to ASTM A 366, *Standard Specification for Steel, Sheet, Carbon, Cold-Rolled Commercial Quality*, if the composite section is prestressed such that no significant tensile stresses are developed under any design loading condition.

4.3.4 Construction, Inspection, and Tests.

4.3.4.1 Concrete LNG containers shall be built in accordance with the applicable requirements of the following standards and publications:

(1) (USA): ACI 318R, *Building Code Requirements for Structural Concrete*; Section 9 of ACI 301, *Specifications for Structural Concrete*; ACI 372R, *Design and Construction of Circular Wire- and Strand Wrapped Prestressed Concrete Structures*; and ACI 373R, *Design and Construction of Circular Prestressed Concrete Structures with Circumferential Tendons*
(2) (CANADA): CSA Standard CAN 3-A23.3, *Design of Concrete Structures*

4.3.4.2 Concrete LNG containers shall be inspected in accordance with ACI Standard 311.4R, *Guide for Concrete Inspection*, and Section 6.5 of this standard.

4.3.4.3 Metal components shall be constructed and tested in accordance with the applicable provisions in Appendix Q of API Standard 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks.*

4.3.4.4 Other materials used in the construction of concrete LNG containers shall be qualified before use based on inspection and test.

4.4 Marking of LNG Containers.

4.4.1 Each container shall be identified by the attachment in an accessible location of a corrosion-resistant nameplate marked with the following information:

(1) Builder's name and date built
(2) Nominal liquid capacity (in barrels, gallons, or cubic meters)
(3) Design pressure for methane gas at top of container
(4) Maximum permitted density of liquid to be stored
(5) Maximum level to which container can be filled with stored liquid *(see 4.1.6)*
(6) Maximum level to which container can be filled with water for test, if applicable
(7) Minimum temperature in degrees Fahrenheit (Celsius) for which the container was designed

4.4.2 Storage containers shall have all penetrations marked with the function of the penetration. Markings shall be visible if frosting occurs.

4.5 Testing of LNG Containers. LNG containers shall be leak tested in accordance with the governing construction code or standard. All leaks shall be repaired.

4.5.1 Where no specific single construction code is applicable, the equivalent of API 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*, shall be applied for containers designed for ≤103 kPa (≤15 psi).

4.5.2 Containers designed for pressures in excess of 103 kPa(g) (15 psi) shall be tested in accordance with the following.

(a) Shop-fabricated containers shall be pressure tested by the manufacturer prior to shipment to the installation site.

(b) The inner tank shall be tested in accordance with the ASME *Boiler and Pressure Vessel Code* or CSA B 51, *Boiler, Pressure Vessel and Pressure Piping Code.* The outer tank shall be leak tested. Piping shall be tested in accordance with Section 6.6.

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

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

Exception No. 1: Field welding shall be permitted on saddle plates or brackets provided for the purpose.

Exception No. 2: Field welding shall be permitted where such repairs or modifications comply with the code or standard under which the container was fabricated originally.

4.6 Container Purging and Cooldown. Before an LNG container is put into service, it shall be purged and cooled in accordance with 11.3.5 and 11.3.6.

4.7 Relief Devices.

4.7.1 General. All containers shall be equipped with pressure and vacuum relief devices in accordance with the following:

(a) API 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*, for containers designed to operate at 15 psi (103 kPa) and below. The relief devices shall be sized in accordance with Section 4.7.

(b) The ASME *Boiler and Pressure Vessel Code,* Section VIII, for containers designed to operate at above 15 psig (103 kPag). The relief devices shall be sized in accordance with Section 4.7.

4.7.2 Relief devices shall communicate directly with the atmosphere. 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. They shall be installed in accordance with the following.

4.7.2.1 Each pressure and vacuum safety relief valve for LNG containers shall be able to be isolated from the container for maintenance or other purposes by means of a manual full-opening stop valve. This stop valve(s) shall be lockable or sealable in the fully open position. Sufficient pressure and vacuum relief valves shall be installed on the LNG container to allow each relief valve to be isolated individually for testing or maintenance while maintaining the full relieving capacities required. 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.

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

4.7.2.3 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.

4.7.3 Relief Device Sizing.

4.7.3.1 Pressure Relief. 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

The pressure relief devices shall be sized to relieve the flow capacity determined for the largest single contingency or any reasonable and probable combination of contingencies.

4.7.3.2* Minimum Capacity. The minimum pressure relieving capacity in kg/hr (lb/hr) shall not be less than 3 percent of the full tank contents in 24 hours.

4.7.3.3 Vacuum Relief. 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

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 tank contents. No vacuum relief capacity credit shall be permitted for gas-repressuring or vapor makeup systems.

4.7.3.4 Fire Exposure. The pressure relieving capacity required for fire exposure shall be computed by the following formula:

$$H = 34{,}500\ FA^{0.82} + H_n \left(\frac{\text{Btu}}{\text{hr}}\right)$$

$$[H = 71{,}000\ FA^{0.82} + H_n\ (\text{watt})]$$

where:

H = total heat influx, Btu/hr (watt)

H_n = normal heat leak in refrigerated tanks, Btu/hr (watt)

A = exposed wetted surface area of the container, ft^2 (m^2)

F = environmental factor (from Table 4.7.3.4)

In the case of large containers, the exposed wetted area shall be the area up to a height of 30 ft (9.15 m) above grade.

Table 4.7.3.4 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	$F = U(1660 - T_f)/34{,}500$
Insulation or thermal protection (metric)	$F = U(904 - T_f)/71{,}000$

Note: U is the 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 is the temperature of vessel content at relieving conditions, °F (°C).

The following shall also apply:

(a)*The insulation shall resist dislodgment by fire fighting equipment, shall be noncombustible, and shall not decompose at temperatures up to 1000°F (538°C). If the insulation does not meet these criteria, no credit for the insulation shall be allowed.

The relieving capacity shall be determined by the following formula:

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

where:

W = relieving capacity in lb/hr (g/s) of product vapor at relieving conditions

L = latent heat of vaporization of the stored liquid at the relieving pressure and temperature, Btu/lb (J/g)

Once the relieving capacity, W, has been determined, the equivalent airflow shall be calculated by the following formula:

$$Q_a = 3.09\,W\frac{\sqrt{TZ}}{\sqrt{M}}\ (\text{ft}^3/\text{hr})$$

$$Q_a = 0.93\,W\frac{\sqrt{TZ}}{\sqrt{M}}\ (\text{m}^3/\text{hr})$$

where:

Q_a = the equivalent flow capacity of air, ft^3/hr (m^3/hr) at 60°F (15°C) and 14.7 psia (101 kPa)

Z = compressibility factor of product vapor at relieving condition

T = absolute temperature of product vapor at relieving conditions, °R (°K)

M = product vapor molecular mass, lbm/lb mol (g/g mol)

Chapter 5 Vaporization Facilities

5.1 Classification of Vaporizers.

5.1.1 Heated Vaporizers. Heated vaporizers shall be classified as those vaporizers that derive their heat from the combustion of fuel, electric power, or waste heat, such as from boilers or internal combustion engines.

5.1.1.1 Integral Heated Vaporizers. Integral heated vaporizers shall be classified as those heated vaporizers in which the heat source is integral to the actual vaporizing exchanger. This classification includes submerged combustion vaporizers.

5.1.1.2 Remote Heated Vaporizers. Remote heated vaporizers shall be classified as those heated vaporizers 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.

5.1.2 Ambient Vaporizers. Ambient vaporizers shall be classified as those vaporizers that derive their heat from naturally occurring heat sources, such as the atmosphere, seawater, or geothermal waters. If the temperature of the naturally occurring heat source exceeds 212°F (100°C), the vaporizer shall be considered to be a remotely heated vaporizer.

If the naturally occurring heat source 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.

5.1.3 Process Vaporizers. Process vaporizers shall be classified as those vaporizers that derive their heat from another thermodynamic or chemical process or in such a fashion to conserve or utilize the refrigeration from the LNG.

5.2 Design and Materials of Construction.

5.2.1 Vaporizers shall be designed, fabricated, and inspected in accordance with the ASME *Boiler and Pressure Vessel Code*, Section VIII, Division 1. Because these vaporizers operate over a temperature range of −260°F to +100°F (−162°C to +37.7°C), the rules of the ASME *Boiler and Pressure Vessel Code*, Section I, Part PVG, are not applicable.

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

5.3 Vaporizer Piping and Intermediate Fluid Piping and Storage.

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

5.3.2 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)].

5.3.3 Automatic equipment shall be provided to prevent the discharge of either LNG or vaporized gas into a distribution system at a temperature either above or below the design temperatures of the sendout system. Such automatic equipment shall be independent of all other flow control systems and shall incorporate a line valve(s) used only for emergency purposes.

5.3.4 Isolation of an idle manifolded vaporizer to prevent leakage of LNG into that vaporizer shall be accomplished with two inlet valves, and a safe means shall be provided to dispose of the LNG or gas that can accumulate between the valves. Ambient vaporizers having inlets of 2 in. (50 mm) or less shall not be required to comply with this provision.

5.3.5 Each heated vaporizer shall be provided with a device to shut off the heat source. The device shall be operated both locally and remotely. The remote location shall be at least 50 ft (15 m) from the vaporizer.

5.3.6 A shutoff valve shall be installed on the LNG line to a heated vaporizer at least 50 ft (15 m) from the vaporizer. If the vaporizer is installed in a building, the shutoff valve shall be installed at least 50 ft (15 m) from the building. This shall be permitted to be the valve provided in 6.3.3.2. The shutoff valve shall be operable either at its installed location or from a remote location, and the valve shall be protected from becoming inoperable due to external icing conditions.

Exception: Where the vaporizer is closer than 50 ft (15 m) to the container from which it is supplied (see 2.2.5.4), in which case the provisions of 5.3.7 shall apply.

5.3.7 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 liquid line. This valve shall be located at least 10 ft (3 m) from the vaporizer and shall close when loss of line pressure (excess flow) occurs, when abnormal temperature is sensed in the immediate vicinity of the vaporizer (fire), or when low temperature in the vaporizer discharge line occurs. At attended facilities, remote operation of this valve from a point at least 50 ft (15 m) from the vaporizer shall be permitted.

5.3.8 If a flammable intermediate fluid is used with a remote heated vaporizer, shutoff valves shall be provided on both the hot and cold lines of the intermediate fluid system. The controls for these valves shall be located at least 50 ft (15 m) from the vaporizer.

5.4 Relief Devices on Vaporizers.

5.4.1 Each vaporizer shall be provided with a safety relief valve(s) sized in accordance with either of the following requirements.

(a) The relief valve capacity of heated or process vaporizers shall be such that the relief valve(s) discharges 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.

(b) The relief valve capacity for ambient vaporizers shall be such that the relief valve(s) discharges at least 150 percent of rated vaporizer natural gas flow capacity (as specified for standard operating conditions) without allowing the pressure to rise more than 10 percent above the vaporizer maximum allowable working pressure.

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

5.5 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.

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

Chapter 6 Piping Systems and Components

6.1 General.

6.1.1 All piping systems shall be in accordance with ASME B 31.3, *Process Piping*. The additional provisions of this chapter shall apply to piping systems and components for flammable liquids and flammable gases with service temperatures below −20°F (−29°C).

Exception: Fuel gas systems covered by NFPA 54, National Fuel Gas Code.

6.1.2 The seismic ground motion used in the piping design shall be the OBE. *(See 4.1.3.2.)* The piping loads shall be determined by a dynamic analysis or by applying an amplification factor of 0.60 to the maximum design spectral acceleration, SDS, as defined in 4.1.3.8. The allowable stress for the piping shall be in accordance with the requirements of ASME B 31.3, *Process Piping*. Container-associated piping up to and including the first container shutoff valve in LNG lines shall be designed to meet the provisions of 4.1.3.3(2).

6.1.3 Piping systems and components shall be designed to accommodate the effects of fatigue resulting from the thermal cycling to which the systems are subjected. Particular consideration shall be given where changes in size of wall thickness occur between pipes, fittings, valves, and components.

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

6.2 Materials of Construction.

6.2.1 General.

6.2.1.1 All piping materials, including gaskets and thread compounds, shall be used with the liquids and gases handled throughout the range of temperatures to which they are subjected. The temperature limitations for pipe materials shall be as specified in ASME B 31.3, *Process Piping*.

6.2.1.2 Piping that can be exposed to the cold 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 significantly increase the emergency shall be in accordance with one of the following:

(1) Made of material(s) that can withstand both its normal operating temperature and the extreme temperature to which it 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.

6.2.1.3 Piping insulation used in areas where the mitigation of fire exposure is necessary shall be made of material(s) that cannot propagate fire in the installed condition and shall maintain any properties that are necessary during an emergency when exposed to fire, heat, cold, or water, as applicable.

6.2.2 Piping.

6.2.2.1 Furnace lap weld and furnace butt shall not be used. Where longitudinal or spiral weld pipe is used (welded with or without filler metal), the weld and heat-affected zone shall comply with Section 323.22 of ASME B 31.3, *Process Piping*.

6.2.2.2 Threaded pipe shall be at least Schedule 80. *(See 6.3.2.1 and 6.3.2.2.)*

6.2.2.3 A liquid line on a storage container, cold box, or other major item of 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 other material that has low resistance to flame temperatures. Transition joints shall be permitted to be used where protected against fire exposure.

Exception No. 1: Liquid lines protected against fire exposure.

Exception No. 2: Loading arms and hoses.

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

6.2.3 Fittings.

6.2.3.1 Threaded nipples shall be at least Schedule 80.

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

6.2.3.3 Bends shall be permitted only in accordance with ASME B 31.3, *Process Piping*, Section 332.

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

6.2.3.5 Compression-type couplings shall not be used where they can be subjected to temperatures below −20°F (−29°C).

Exception: Couplings meeting the requirements of ASME B 31.3, Process Piping, Section 315.

6.2.4 Valves.

6.2.4.1 In addition to complying with ASME B 31.3, *Process Piping*, Section 307, valves shall comply with ASME B 31.5, *Refrigeration Piping*; ASME B 31.8, *Gas Transmission and Distribution Piping Systems*; or API 6D, *Specification for Pipeline Valves*, if design conditions fall within the scope of these standards.

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

6.3 Installation.

6.3.1 Bolted Connections. Care shall be taken to ensure the tightness of all bolted connections. Spring washers or similar devices designed to compensate for the contraction and expansion of bolted connections during operating cycles shall be used where required.

6.3.2 Piping Joints.

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

Exception: Joints of 4 in. (100 mm) nominal diameter or less shall be permitted to be threaded where necessary for special connections to equipment or components, where the connection is not subject to fatigue-producing stresses.

6.3.2.2 The number of threaded or flanged joints shall be kept to a minimum and used only where necessary, such as at material transitions or instrument connections, or where required for maintenance. If threaded joints are unavoidable, they shall be seal-welded or sealed by other means proven by test.

6.3.2.3 Metals shall be permitted to be joined for cryogenic service by silver brazing. Silver brazing shall be permitted to be used in joining copper to itself, to copper alloys, and to stainless steel. Dissimilar metals shall be joined by flanges or transition joint techniques that have been proven by test.

6.3.2.4 The selection of gasket material shall include the consideration of exposure to fire.

6.3.3 Valves.

6.3.3.1 Extended bonnet valves shall be installed with packing seals in a position that prevents leakage or malfunction due to freezing. If the extended bonnet in a cryogenic liquid line is installed at an angle greater than 45 degrees from the upright vertical position, evidence of satisfactory service in the installed position shall be demonstrated.

6.3.3.2 Shutoff valves shall be provided on container, tank, and vessel connections.

Exception No. 1: Relief valve connections. [Shutoff valves shall be permitted only at connections for relief valves in accordance with the ASME Boiler and Pressure Vessel Code, Section VIII, Division 1, UG-125(d), and Appendix M, M-5 and M-6.]

Exception No. 2: Connections for liquid level alarms shall be as required by 7.1.1.2.

Exception No. 3: Connections that are blind flanged or plugged.

Shutoff valves shall be located as close as practical to such containers, tanks, and vessels and shall be located inside the impounding area.

6.3.3.3 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.

6.3.3.4 In the design of the piping system, consideration shall be given to the installation of shutoff or block valves as a means of limiting the contained volume that could be discharged in the event of a piping system failure.

(a) Sufficient valves shall be provided that can be operated both at the installed location and from a remote location to allow shutdown of the process and transfer systems by system or area, or to allow complete shutdown in the event of an emergency.

(b) In addition to the provisions of 6.3.3.2, 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 shall remain closed except during the operating period
(3) A check valve on filling connections

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

6.3.3.6 Powered operators shall be provided for emergency shutoff valves that would require excessive time to operate during an emergency or if the valve is 8 in. (200 mm) or larger. Means for manual operation shall be provided.

6.3.4 Welding.

6.3.4.1 Qualification and performance of welders shall be in accordance with Section 328.2 of ASME B 31.3, *Process Piping*, and 6.3.4.2 of this standard.

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

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

6.3.4.3 Oxygen-fuel gas welding shall not be permitted.

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

(a) Markings shall be made with a material compatible with the basic material or with a round-bottom, low-stress die.

Exception: Materials less than $^1/_4$ in. (6.35 mm) in thickness shall not be die-stamped.

(b) Marking materials that are corrosive to the pipe material shall not be used. Under some conditions, marking materials containing carbon or heavy metals can cause corrosion of aluminum. Marking materials containing chloride or sulfur compounds cause corrosion of some stainless steels. Chalk, wax-base crayons, or marking inks with organic coloring shall be permitted to be used.

6.4 Pipe Supports.

6.4.1 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.

6.4.2 Pipe supports for cold lines shall be designed to prevent excessive heat transfer, which can result in piping restraints caused by ice formations or embrittlement of supporting steel. The design of supporting elements shall conform to ASME B 31.3, *Process Piping*, Section 321.

6.5* Piping Identification. Piping shall be identified by color-coding, painting, or labeling. Any existing company color code scheme for the identification of piping systems shall be permitted to be used.

6.6 Inspection and Testing of Piping.

6.6.1 Pressure Testing. Pressure tests shall be conducted in accordance with ASME B 31.3, *Process Piping*, Section 345. To avoid possible brittle failure, carbon and low-alloy steel piping shall be pressure tested at metal temperatures suitably above their nil ductility transition temperature.

6.6.2 Record Keeping. Records of pressure, test medium temperature, and ambient temperature shall be maintained for the duration of each test, and these records shall be maintained for the life of the facility or until such time as a retest is conducted.

6.6.3 Welded Pipe Tests.

6.6.3.1 Longitudinal or spiral welded pipe that is subjected to service temperatures below −20°F (−29°C) shall have a design pressure of less than $^2/_3$ of the mill proof test pressure or subsequent shop or field hydrostatic test pressure.

Exception: Pipe that has been subjected to 100 percent radiographic or ultrasonic inspection of the longitudinal or spiral weld.

6.6.3.2 All circumferential butt welds shall be examined fully by radiographic or ultrasonic inspection.

Exception No. 1: Liquid drain and vapor vent piping with an operating pressure that produces a hoop stress of less than 20 percent specified minimum yield stress shall not be required to be nondestructively tested if it has been inspected visually in accordance with ASME B 31.3, Process Piping, Section 344.2.

Exception No. 2: Pressure piping operating above −20°F (−29°C) shall have 30 percent of each day's circumferentially welded pipe joints nondestructively tested over the entire circumference in accordance with ASME B 31.3.

6.6.3.3 All socket welds and fillet welds shall be examined fully by liquid penetrant or magnetic particle inspection.

6.6.3.4 All fully penetrated groove welds for branch connections (as required by ASME B 31.3, *Process Piping*, Section 328.5.4) shall be examined fully by in-process examination in accordance with ASME B 31.3, Section 344.7, as well as by liquid penetrant or magnetic particle techniques after the final pass of the weld.

Exception: If specified in the engineering design or specifically authorized by the inspector, examination by radiographic or ultrasonic techniques shall be permitted to be substituted for the examinations required by 6.6.3.4.

6.6.4 Inspection Criteria. Nondestructive examination methods, limitations on defects, the qualifications of the authorized inspector, and the personnel performing the examination shall meet the requirements of ASME B 31.3, *Process Piping*, Sections 340 and 344.

Exception: Substitution of in-process examination for radiography or ultrasonics as permitted in ASME B 31.3, Paragraph 341.4.1, shall be prohibited.

6.6.5 Record Retention. Test records and written procedures required when conducting nondestructive examinations shall be maintained for the life of the piping system or until such time as a reexamination is conducted.

Records and certifications pertaining to materials, components, and heat treatment as required by ASME B 31.3, *Process Piping*, subparagraphs 341.4.1(c) and 341.4.3(d) and Section 346, shall be maintained for the life of the system.

6.7 Purging of Piping Systems.

6.7.1* Systems shall be purged of air or gas in a safe manner.

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

6.8 Safety and Relief Valves.

6.8.1 Pressure-relieving safety devices shall be arranged so that the possibility of damage to piping or appurtenances is reduced to a minimum. The means for adjusting relief valve set pressure shall be sealed.

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

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

6.8.2.2 Discharge from such valves shall be directed to minimize hazard to personnel and other equipment.

6.9 Corrosion Control.

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

6.9.2 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. Tapes or other packaging materials that are corrosive to the pipe or piping components shall not be used. Where insulation materials can cause corrosion of aluminum or stainless steels, inhibitors or waterproof barriers shall be utilized.

Chapter 7 Instrumentation and Electrical Services

7.1 Liquid Level Gauging.

7.1.1 LNG Containers.

7.1.1.1 LNG containers shall be equipped with two independent liquid level gauging devices. Density variations shall be considered in the selection of the gauging devices. These gauges shall be designed and installed so that it is possible to replace them without taking the tank out of operation.

7.1.1.2 The container shall be provided with two high-liquid-level alarms, which shall be permitted to be part of the liquid level gauging devices. They shall be independent of each other. The alarm shall be set so that the operator has sufficient time to stop the flow without exceeding the maximum permitted filling height and shall be located so that it is audible to personnel controlling the filling. The high-liquid-level flow cutoff device required in 7.1.1.3 shall not be considered as a substitute for the alarm.

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

7.1.2 Tanks for Refrigerants or Flammable Process Fluids.

7.1.2.1 Each storage tank shall be equipped with a liquid level gauging device. If it is possible to overfill the tank, a high-liquid-level alarm shall be provided in accordance with 7.1.1.2.

7.1.2.2 The requirements of 7.1.1.3 shall also apply to installations of flammable refrigerants.

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

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

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

7.4.1 Vaporizers. 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.

7.4.2 Heated Foundations of Cryogenic Containers and Equipment. 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.

7.5 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 failsafe condition that is maintained until the operators can take appropriate action either to reactivate or to secure the system.

7.6 Electrical Equipment.

7.6.1 Electrical equipment and wiring shall be of the type specified by and shall be installed in accordance with NFPA 70, *National Electrical Code*®, or CSA C 22.1, *Canadian Electrical Code*, for hazardous locations.

7.6.2 Fixed electrical equipment and wiring installed within the classified areas specified in Table 7.6.2 shall comply with Table 7.6.2 and Figures 7.6.2(a) through 7.6.2(d) and shall be installed in accordance with NFPA 70, *National Electrical Code*, for hazardous locations.

FIGURE 7.6.2(a) Extent of classified area around containers.

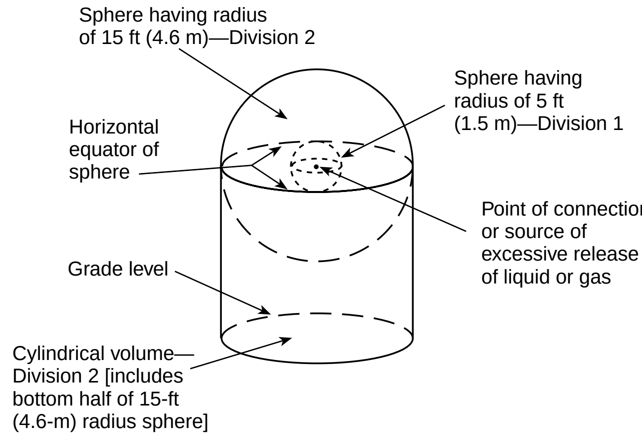


FIGURE 7.6.2(b) Dike height less than distance from container to dike (*H* less than *x*).

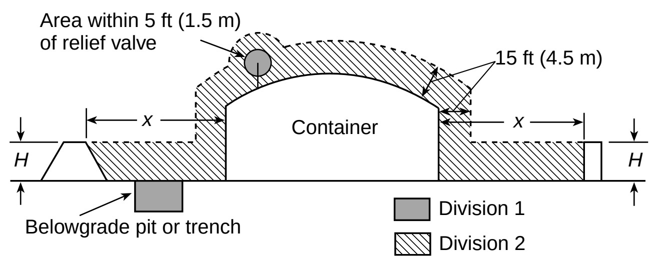


FIGURE 7.6.2(c) Dike height less than distance from container to dike (*H* greater than *x*).

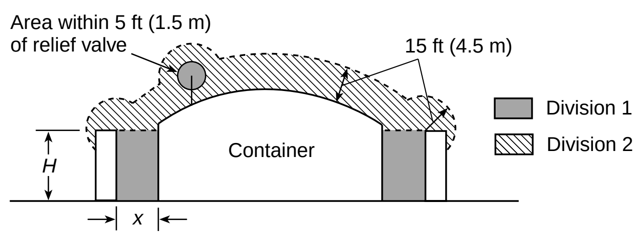


FIGURE 7.6.2(d) Container with liquid level below grade or top of dike.

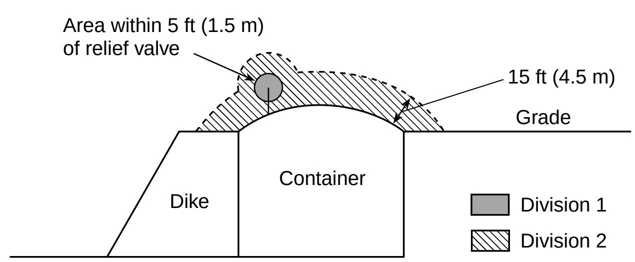


Table 7.6.2 Electrical Area Classification

Part	Location	Group D, Division[1]	Extent of Classified Area[2]
A	**LNG storage containers with vacuum breakers**		
	Inside of containers	2	Entire container interior.
B	**LNG storage container area**		
	Indoors	1	Entire room.
	Outdoor, aboveground containers (other than small containers)[3]	1	Open area between a high-type dike and container wall where dike wall height exceeds distance between dike and container walls. *[See Figure 7.6.2(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 7.6.2(b).]*
	Outdoor, belowground containers	1	Within any open space between container walls and surrounding grade or dike. *[See Figure 7.6.2(d).]*
		2	Within 15 ft (4.5 m) in all directions from roof and sides. *[See Figure 7.6.2(d).]*
C	**Nonfired LNG process areas containing pumps, compressors, heat exchangers, pipelines, connections, small containers, etc.**		
	Indoors with adequate ventilation[4]	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 7.6.2(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 direct path of relief valve discharge.
F	**Operational bleeds, drips, vents, or drains**		
	Indoors with adequate ventilation[4]	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.
G	**Tank car, tank vehicle, and container loading and unloading[5]**		
	Indoors with adequate ventilation[4]	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.

(Sheet 1 of 2)

Table 7.6.2 Electrical Area Classification ***(Continued)***

Part	Location	Group D, Division[1]	Extent of Classified Area[2]
	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 7.6.2(a).]*
H	**Electrical seals and vents specified in 7.6.3, 7.6.4, and 7.6.5**	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.

(Sheet 2 of 2)

[1]See Article 500, "Hazardous (Classified) Locations" in NFPA 70, *National Electrical Code*, for definitions of classes, groups, and divisions. Most of the flammable vapors and gases found within the facilities covered by this standard are classified as Group D. Ethylene is classified as Group C. Much available electrical equipment for hazardous locations is suitable for both groups.
[2]The classified area shall not extend beyond an unpierced wall, roof, or solid vaportight partition.
[3]Small containers are those that are portable and of less than 200-gal (760-L) capacity.
[4]Ventilation is considered adequate where provided in accordance with the provisions of this standard.
[5]Where classifying the extent of the hazardous area, consideration shall be given to possible variations in the spotting of tank cars and tank vehicles at the unloading points and the effect these variations might have on the point of connection.

Exception: For the purpose of designing electrical equipment, the interior of an LNG container shall be permitted to be unclassified where the following conditions are met:

(a) Electrical equipment shall be deenergized and locked out until the container is purged of air.

(b) Electrical equipment is deenergized and locked out prior to allowing air into the container.

(c) The electrical system is designed and operated to deenergize the equipment automatically when the pressure in the container is reduced to atmospheric pressure.

7.6.3 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.

7.6.3.1 Each seal, barrier, or other means used to comply with 7.6.3 shall be designed to prevent the passage of flammable fluids through the conduit, stranded conductors, and cables.

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

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

7.6.3.4 Where secondary seals are used, the space between the primary and secondary seals shall be continuously vented to the atmosphere. Similar provisions shall be made on double-integrity primary sealant systems of the type used for submerged motor pumps.

7.6.3.5 The seals specified in 7.6.3, 7.6.4, and 7.6.5 shall not be used to meet the sealing requirements of NFPA 70, *National Electrical Code*, or CSA C 22.1, *Canadian Electrical Code*.

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

7.6.5 The venting of a conduit system shall be done in a manner that minimizes the possibility of damage to personnel and equipment, considering the properties of the liquid or gas and the potential for ignition.

7.7 Electrical Grounding and Bonding.

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

7.7.2 Bonding. 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.

7.7.3* Stray or Impressed Currents. 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.

7.7.4* Lightning Protection. Lightning protection shall not be required on LNG storage containers.

Exception: Lightning protection ground rods shall be provided for tanks supported on nonconductive foundations for personnel and foundation protection.

Chapter 8 Transfer of LNG and Refrigerants

8.1 General.

8.1.1 This chapter shall apply to 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.

8.1.2 Transfer facilities shall comply with the provisions of this standard, such as those applying to siting, piping systems, and instrumentation, as well as the specific provisions of this chapter.

8.2 Piping System.

8.2.1 Isolation valves shall be installed so that each transfer system can be isolated at its extremities. Where power-operated isolation valves are installed, an analysis shall be made to determine that the closure time will not produce a hydraulic shock capable of causing line or equipment failure. If excessive stresses are indicated by the analysis, an increase of the valve closure time or other methods shall be used to reduce the stresses to a safe level.

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

8.2.3 Check valves shall be provided as required in 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.

8.3 Pump and Compressor Control.

8.3.1 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. 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. Controls located aboard a marine vessel shall be considered to be in compliance with this provision.

8.3.2 Signal lights shall be provided at the loading or unloading area to indicate when a remotely located pump or compressor used for loading or unloading is idle or in operation.

8.4 Marine Shipping and Receiving.

8.4.1* The design, construction, and operation of piers, docks, and wharves shall comply with the requirements of the authorities having jurisdiction.

8.4.2 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 of transfer connection while LNG or flammable fluids are being transferred through piping systems. Ship bunkering shall be permitted to be done if that bunkering is from a pipeline rather than from a barge.

8.4.3 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. 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 in accordance with federal regulations.

8.4.4 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. 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. 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. 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 10-minute duration. Valves shall be located at the point of hose or arm connection to the manifold. Bleeds or vents shall discharge to a safe area.

8.4.5 In addition to the isolation valves at the manifold, each vapor return and liquid transfer line shall be provided with a readily accessible isolation valve located on shore near the approach to the pier or dock. Where more than one line is involved, the valves shall be grouped in one location. Valves shall be identified for their service. Valves 8 in. (200 mm) and larger shall be equipped with powered operators. Means for manual operation shall be provided.

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

8.4.7 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.

8.5 Tank Vehicle and Tank Car Loading and Unloading Facilities.

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

8.5.1.1 Tank vehicles and tank cars under the jurisdiction of the U.S. Department of Transportation (DOT) or Transport Canada, including those in interstate commerce, shall comply with the regulations and specifications of that federal agency.

8.5.1.2 Tank vehicles not under the jurisdiction of the DOT shall comply with the following standards:

(1) LNG tank vehicles — CGA 341, *Standard for Insulated Cargo Tank Specification for Cryogenic Liquids*
(2) LP-Gas tank vehicles — NFPA 58, *Liquefied Petroleum Gas Code*
(3) Flammable liquid tank vehicles — NFPA 385, *Standard for Tank Vehicles for Flammable and Combustible Liquids*

8.5.2 A rack structure, if provided, shall be constructed of noncombustible material, such as steel or concrete.

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

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

8.5.5 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 of liquid, and depressurized before disconnecting. Bleeds or vents shall discharge to a safe area.

8.5.6 In addition to the isolation valving at the manifold, an emergency 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. These valves shall be readily accessible for emergency use. A single valve shall be permitted to be installed in a common line to multiple loading or unloading areas.

In installations 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 permitted to be used.

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

8.6 Pipeline Shipping and Receiving.

8.6.1 Isolation valves shall be provided at all points where transfer systems connect into pipeline systems.

8.6.2 Provisions shall be made to ensure that transfers into pipeline delivery systems cannot exceed the pressure or temperature limitations of the pipeline system.

8.6.3 Loading and unloading areas shall be posted with signs that read “No Smoking.”

8.6.4 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.

8.6.5 Bleed or vent connections shall be provided so that loading arms and hoses can be drained and depressurized prior to disconnecting. These bleeds or vents shall discharge to a safe area.

8.6.6 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.

8.7 Hoses and Arms.

8.7.1 Hoses or arms used for transfer shall be designed for the temperature and pressure conditions encountered. Hoses shall be approved for the service and shall be designed for a bursting pressure of not less than five times the working pressure.

8.7.2 Flexible metallic hose or pipe and swivel joints shall be used where operating temperatures are expected to be below −60°F (−51°C).

8.7.3 Loading arms used for marine loading or unloading shall be provided with alarms to indicate that the arms are approaching the limits of their extension envelopes.

8.7.4 Provisions shall be made for adequately supporting the loading hose or arm. Counterweights shall take into consideration any ice formation on uninsulated hoses or arms.

8.7.5 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.

8.8 Communications and Lighting.

8.8.1 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. Communications shall be permitted to be by means of telephone, public address system, radio, or signal lights.

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

Chapter 9 Fire Protection, Safety, and Security

9.1 General.

9.1.1 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. These provisions augment the leak and spill control provisions in other chapters. This chapter also includes basic plant security provisions.

9.1.2* Fire protection shall be provided for all LNG facilities. The extent of such protection shall be determined by an evaluation based on sound fire protection engineering principles, analysis of local conditions, hazards within the facility, and exposure to or from other property. The evaluation shall determine the following, as a minimum:

(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) Fire protection water systems
(5) Fire extinguishing and other fire control equipment
(6) The equipment and processes to be incorporated within the emergency shutdown (ESD) system, including analysis of subsystems, if any, and the need for depressurizing specific vessels or equipment during a fire emergency
(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 his or her respective emergency duties

9.1.3 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.

9.2 Emergency Shutdown Systems.

9.2.1 Each LNG facility shall incorporate an ESD system(s) that, when operated, isolates or shuts off a source of LNG, flammable liquids, flammable refrigerant, or flammable gases, and shuts down equipment whose continued operation could add to or sustain an emergency. Any equipment, such as valves or control systems, that is specified in another chapter of this standard shall be permitted to be used to satisfy the requirements of an ESD system except where indicated in this standard.

9.2.2 If equipment shutdown will introduce an additional hazard or result in substantial mechanical damage to equipment, the shutdown of such equipment or its auxiliaries shall be permitted to be omitted from the ESD system provided that the effects of the continued release of flammable or combustible fluids are controlled.

9.2.3 The ESD system(s) shall be of a failsafe design or shall be otherwise installed, located, or protected to minimize the possibility that it becomes inoperative in the event of an emergency or failure at the normal control system. ESD systems that are not of a failsafe design shall have all components that are located within 50 ft (15 m) of the equipment to be 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

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

9.2.5 Initiation of the ESD system(s) shall be either manual, automatic, or both manual and automatic, depending on the results of the evaluation performed in accordance with 9.1.2. 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 distinctly and conspicuously with their designated function.

9.3 Fire and Leak Control.

9.3.1 Those areas, including enclosed buildings, that have a potential for flammable gas concentrations, LNG or flammable refrigerant spills, and fire shall be monitored as required by the evaluation in 9.1.2.

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

9.3.3 Fire detectors shall sound an alarm at the plant site and at a constantly attended location if the plant site is not attended continuously. In addition, if so determined by an evaluation in accordance with 9.1.2, fire detectors shall be permitted to activate portions of the ESD system.

9.3.4 The detection systems determined from the evaluation in 9.1.2 shall be designed, installed, and maintained in accordance with NFPA 72, *National Fire Alarm Code*, or NFPA 1221, *Standard for the Installation, Maintenance, and Use of Emergency Services Communications Systems*, as applicable.

9.4 Fire Protection Water Systems.

9.4.1 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.

Exception: Where an evaluation in accordance with 9.1.2 indicates the use of water is unnecessary or impractical.

9.4.2 The design of fire water supply and distribution systems, if provided, shall provide for the simultaneous supply of those 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 not less than 2 hours.

9.5 Fire Extinguishing and Other Fire Control Equipment.

9.5.1* Portable or wheeled fire extinguishers recommended by their manufacturer for gas fires shall be available at strategic locations, as determined in accordance with 9.1.2, within an LNG facility and on tank vehicles. These extinguishers shall be provided and maintained in accordance with NFPA 10, *Standard for Portable Fire Extinguishers*.

9.5.2 If provided, automotive and trailer-mounted fire apparatus shall not be used for any other purpose. Fire trucks shall conform to the applicable portions of NFPA 1901, *Standard for Automotive Fire Apparatus*.

9.5.3 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).

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

9.7 Personnel Safety.

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

9.7.2 Those employees who are involved in emergency activities, as determined in accordance with 9.1.2, shall be equipped with the necessary protective clothing and equipment and qualified in accordance with NFPA 600, *Standard on Industrial Fire Brigades*.

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

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

9.8* Security.

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

9.8.2 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

9.8.3 The provisions of 9.8.2 shall be permitted to be met by either a single continuous enclosure or several independent enclosures. Where the enclosed area exceeds 1250 ft^2 (116 m^2), at least two exit gates or doors shall be provided for rapid escape of personnel in the event of an emergency.

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

9.9 Other Operations.

9.9.1 Manual emergency depressurizing means shall be provided where necessary for safety. Portions of the plant that can be isolated from storage tanks or other sources of supply can be depressurized by venting to the atmosphere. The discharge shall be directed so as to minimize exposure to personnel or equipment.

9.9.2 Taking an LNG container out of service shall not be regarded as a normal operation and shall not be attempted on any routine basis. All such activities shall require the preparation of detailed procedures.

Chapter 10 Alternate Requirements for Stationary Applications Using ASME Containers

10.1 Scope. This chapter provides requirements for the installation, design, fabrication, and siting of LNG installations using containers of 379-m^3 (100,000-US gal) capacity and less constructed in accordance with the ASME *Boiler and Pressure Vessel Code*. The maximum aggregate storage capacity shall be 1060 m^3 (280,000 U.S. gal).

10.2 General Requirements.

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

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

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

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

10.2.5 Designers, fabricators, and constructors of LNG facility equipment shall be competent in the design, fabrication, and construction of LNG containers, cryogenic equipment, piping systems, fire protection equipment, and other components of the facility. Supervision shall be provided for the fabrication, construction, and acceptance tests of facility components to the extent necessary to ensure that facilities are structurally sound and otherwise in compliance with this standard.

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

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

10.3 Containers.

10.3.1 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*. Compliance with this requirement 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."

10.3.2 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. Bellows shall not be permitted within the insulation space.

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

10.3.4 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 other agency that registers pressure vessels.

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

10.3.6 The outer tank shall be of welded construction.

(a) Any of the carbon steels in Section VIII, Part UCS of the ASME *Boiler and Pressure Vessel Code* shall be permitted to be used 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.

Exception: Materials with a melting point below 2000°F (1093°C) where the container is buried or mounded.

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

(1) VIII, Parts UG-28, -29, -30, and -33, of the ASME *Boiler and Pressure Vessel Code*, using an external pressure of not less than 15 psi (100 kPa)

(2) CGA 341, *Standard for Insulated Cargo Tank Specification for Cryogenic Liquids*, Paragraph 3.6.2

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, -29, -30, and -33, using an external pressure of 15 psi (100 kPa).

(c) The outer tank shall be equipped with a relief device or other device to release internal pressure. The discharge area shall be at least 0.00024 in.^{2}/lb (0.0034 cm^2/kg) of the water capacity of the inner tank, but the area shall not exceed 300 in.^{2} (2000 cm^2). Such a 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 less.

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

10.3.7 Seismic Design.

10.3.7.1 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:

Horizontal force:

$$V = Z_c \times W$$

where:

Z_c = the seismic coefficient equal to $0.60S_{SC}$

S_{SC} = the maximum design spectral acceleration determined in accordance with the nonbuilding structures provisions of the *NEHRP Recommended Provisions for Seismic Regulation for New Buildings and Other Structures*, using an importance factor, *I*, of 1.0, for the site class most representative of the site conditions where the LNG facility is located

W = the total weight of the container and its contents

Design vertical force:

$$P = {}^2/_3 \times Z_c \times W$$

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

10.3.7.2 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.

10.3.7.3 The requirements of this section shall apply to ASME containers built prior to July 1, 1996, when reinstalled.

10.3.8 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:

(1) Builder's name and date 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

10.3.9 All penetrations on storage containers shall be identified. Markings shall be legible under all conditions.

10.4 Container Filling. Containers designed to operate at a pressure in excess of 15 psi (100 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.

10.5 Container Foundations and Supports.

10.5.1 LNG container foundations shall be designed and constructed in accordance with recognized structural and geotechnical engineering practices, including provisions for seismic loading as specified in 10.3.7. Saddles and legs shall be designed in accordance with recognized structural engineering practice, including those for shipping loads, erection loads, wind loads, and thermal loads. Foundations and supports shall be protected to have a fire resistance rating of not less than 2 hours. If insulation is used to achieve this requirement, it shall be resistant to dislodgement by fire hose streams.

10.5.2 Where the LNG storage container is installed in an area subject to flooding, the container shall be secured in a manner that prevents the release of LNG or flotation of the container in the event of a flood.

10.6 Container Installation.

10.6.1 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 buildings and the line of adjoining property
(2) 1000 gal (3.8 m^3) or less, 10 ft (3.0 m) from buildings and the line of adjoining property

10.6.2 The minimum distance from edge of impoundment or container drainage system to buildings and property lines and between containers shall be in accordance with Table 10.6.2 for aboveground and mounded tanks larger than 1000 gal (3.8 m^3).

Exception: With the approval of the authority having jurisdiction, such equipment shall be permitted to be located a shorter distance from buildings or walls constructed of concrete or masonry but at least 10 ft (3.0 m) from any building openings.

10.6.3 Underground LNG tanks shall be installed in accordance with Table 10.6.3.

Table 10.6.2 Distances from Impoundment Areas to Buildings and Property Lines for Aboveground and Mounded LNG Tanks

Container Water Capacity		Minimum Distance from Edge of Impoundment or Container Drainage System to Buildings and Property Lines		Minimum Distance Between Storage Containers	
gal	m^3	ft	m	ft	m
1000–2000	1.9–7.6	15	4.6	5	1.5
2001–15,000	7.6–56.8	25	7.6	5	1.5
15,001–30,000	56.8–114	50	15	5	1.5
30,001–70,000	114–265	75	23	$^1/_4$ of the sum of the diameters of adjacent containers [5 ft (1.5 m) minimum]	
>70,000	>265	0.7 times the container diameter, minimum 100 ft			

Table 10.6.3 Spacing of Underground LNG Containers

Container Water Capacity (gal)	Minimum Distance from Buildings and the Line of Adjoining Property (ft)	Distance Between Containers (ft)
<15,000	15	15
15,000–30,000	25	15
30,001–100,000	40	15

10.6.4 Buried and underground containers shall be provided with means to prevent the 32°F (0°C) isotherm from penetrating the soil. Where heating systems are used, they shall be installed such that any heating element or temperature sensor used for control can be replaced.

10.6.5* All buried or mounded components in contact with the soil shall be constructed from corrosion-resistant material or protected from corrosion deterioration.

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

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

10.6.8 Points of 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

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

10.7 Product Retention Valves. All liquid and vapor connections, except relief valve and instrument connections, shall be equipped with automatic failsafe product retention valves. These automatic 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

Connections used only for flow into the container shall be permitted to be equipped with two backflow valves, in series, in lieu of the requirements in 10.7(1) through (3). The 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.

10.8 LNG Spill Containment.

10.8.1 Means shall be provided by 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.

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

10.8.3 Impounding areas serving aboveground and mounded LNG containers shall have a minimum volumetric holding capacity, *V*, 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) For impounding areas serving one or more than one container with provision made to prevent low-temperature or fire exposure resulting from the leakage from any one container served from causing subsequent leakage from any other container served, the volume of the dike shall be the total volume of liquid in the largest container served, assuming the container is full.
(2) For impounding areas serving more than one container without provision made in accordance with 10.8.3(a), the volume of the dike shall be the total volume of liquid in all containers served, assuming all containers are full.

10.8.4 Provision shall be made to clear rain or other water from the impounding area. Automatically controlled sump pumps shall be permitted if equipped with an automatic cutoff device that prevents their operation when exposed to LNG temperatures. Piping, valves, and fittings whose failure could allow liquid to escape from the impounding area shall be capable of withstanding continuous exposure to LNG temperatures. If gravity drainage is employed for water removal, provision shall be made to prevent the escape of LNG by way of the drainage system.

10.9 Inspection.

10.9.1 Prior to initial operation, containers shall be inspected to ensure compliance with the engineering design and material, fabrication, assembly, and test provisions of the chapter. The operator shall be responsible for this inspection.

10.9.2 The performance of any part of the inspection shall be permitted to be delegated to inspectors who are employees of the operator's own organization, an engineering or scientific organization, or a recognized insurance or inspection company. Inspectors shall be qualified in accordance with the code or standard applicable to the container and as specified in this standard.

10.10 Testing of LNG Containers.

10.10.1 Shop-fabricated containers shall be pressure tested by the manufacturer prior to shipment to the installation site. The inner tank shall be tested in accordance with the ASME *Boiler and Pressure Vessel Code*. The outer tank shall be leak tested. Piping shall be tested in accordance with ASME B 31.3, *Process Piping*.

10.10.2 Containers and associated piping shall be leak tested prior to filling the container with LNG.

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

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

Exception No. 1: Field welding shall be permitted on saddle plates or brackets provided for the purpose.

Exception No. 2: Field welding shall be permitted where such repairs or modifications comply without the code or standard under which the container was fabricated originally.

10.11 Piping.

10.11.1 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, *Process Piping*.

10.11.2 The following requirements also shall apply.

(a) Type F piping, spiral welded piping, and furnace butt-welded steel products shall not be permitted.

(b) All welding or brazing shall be performed by personnel qualified to the requirements of the ASME *Boiler and Pressure Vessel Code*, Section IX.

(c) Oxygen-fuel gas welding shall not be permitted.

(d) Brazing filler metal shall have a melting point exceeding 1000°F (538°C).

(e) All piping and tubing shall be austenitic stainless steel for all services below −20°F (−29°C).

(f) All piping and piping components shall have a minimum melting point of 1500°F (816°C).

Exception No. 1: Gaskets, seats, and packing.

Exception No. 2: Aluminum shall be permitted to be used downstream of a product retention valve in vaporizer service.

(g) 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, *Process Piping*, Section 315.

(h) Stab-in branch connections shall not be permitted.

(i) Extended bonnet valves shall be used for all cryogenic liquid service. The valves shall be installed so that the bonnet is at an angle of not more than 45 degrees from the upright vertical position.

(j) The level of inspection of piping shall be specified.

10.12 Container Instrumentation.

10.12.1 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 failsafe condition that can be maintained until the operators can take action to reactivate or secure the system.

10.12.2 Level Gauging. LNG containers shall be equipped with two independent liquid level devices. One shall provide a continuous level indication ranging from full to empty and shall be maintainable or replaceable without taking the container out of service.

Exception: Containers smaller than 1000 gal (3.79 m^3) shall be permitted to be equipped with a fixed length dip tube only.

10.12.3 Pressure Gauging.

10.12.3.1 Each container shall be equipped with a pressure gauge connected to the container at a point above the maximum liquid level. The pressure gauge dial shall have a permanent mark indicating the maximum allowable working pressure (MAWP) of the container.

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

10.12.4 Pressure Control.

10.12.4.1 Safety relief valves on containers designed for pressures exceeding 15 psi (100 kPa) shall be provided to maintain the internal pressure of LNG containers in accordance with the ASME *Boiler and Pressure Vessel Code*, including conditions resulting from operational upset, vapor displacement, and flash vaporization resulting from pump recirculation and fire. The valves shall communicate directly with the atmosphere. They shall be sized in accordance with Section 4.7.3 or CGA S-1.3, *Pressure Relief Device Standards — Part 3 — Compressed Gas Storage Containers*.

10.12.4.2 Each pressure relief valve for inner LNG containers shall be able to be isolated from the container for maintenance or other purposes by means of a manual full-opening stop valve. This stop valve(s) shall be lockable or sealable in the fully open position. Pressure relief valves shall be installed on the LNG container to allow each relief valve to be isolated individually for testing or maintenance while maintaining the full capacities determined in 4.7.3. Where only one pressure relief valve is required, a full-port opening three-way valve shall be permitted to be used under the pressure relief valve and its required spare in lieu of individual valves beneath each pressure relief valve.

10.12.4.3 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.

10.12.4.4 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.

10.13 Fire Protection and Safety. The following requirements shall apply: Section 9.1, Section 9.2, 9.3.1, 9.3.4, Section 9.4, Sections 9.5 and 9.6, 9.7.2, and 9.7.3.

10.14 Gas Detectors. An operating portable flammable gas indicator shall be readily available.

10.15 Operations and Maintenance.

10.15.1 General. Each facility shall have written operating, maintenance, and training procedures based on experience, knowledge of similar facilities, and conditions under which they will be operated. This section contains basic requirements and minimum standards for the safety aspects of the operation and maintenance of LNG facilities, as well as personnel training.

10.15.2 Basic 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

10.15.3 Documentation of Operating Procedures.

10.15.3.1 Manual of Operating Procedures. Each facility shall have a written manual of operating procedures. The facility shall operate all components in accordance with the manual. The manual shall be accessible to operating and maintenance personnel. It shall be updated as required by changes in equipment or procedures.

10.15.3.2 Operating Manual Contents. The manual shall include procedures for 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
(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 these 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

10.15.3.3 Emergency Procedures. The types of emergencies shall include, at a minimum, those 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. Consideration shall include but not be limited to the following:

(a) Procedures shall be in place 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.

(b) Procedures shall be in place for recognizing an uncontrollable emergency and for taking action to ensure the following:

(1) Harm to the personnel at the facility and to the public is minimized
(2) Prompt notification of the emergency to the appropriate local officials, including the possible need to evacuate persons from the vicinity of the facility, is provided

(c) Procedures shall be in place 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.

(d) The procedures and steps of 10.15.3.3(c) shall include methods of advising the appropriate local offices 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

(e) Normally, gas fires (including LNG) should not be extinguished until the fuel source has been shut off, unless the fire would create more of a hazard than the gas dispersion.

10.15.3.4 Cooldown Procedure.

10.15.3.4.1 Each facility shall have procedures to ensure that the cooldown of each system of components that is under its 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, having regard to the performance of expansion and contraction devices.

10.15.3.4.2 Each facility shall have procedures to check each cryogenic piping system that is under its control during and after cooldown stabilization for leaks in areas where there are flanges, valves, and seals.

10.15.3.5 Purging. Purging procedures shall be developed that minimize the presence of a combustible mixture in plant piping or equipment when a system is being placed into or taken out of operation.

10.15.3.6 Loading or Unloading Operations.

10.15.3.6.1 General.

(a) At least one qualified person shall be in constant attendance while loading or unloading is in progress.

(b) Written procedures shall be available to cover all transfer operations and shall cover emergency as well as normal operating procedures. They shall be kept up-to-date and available to all personnel engaged in transfer operations.

(c) Sources of ignition, such as welding, flames, and unclassified electrical equipment, shall not be permitted in loading or unloading areas while transfer is in progress.

(d) Loading and unloading areas shall be posted with signs that read "No Smoking."

(e) 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.

(f) Prior to transfer, gauge readings shall be obtained or inventory established to ensure that the receiving vessel cannot be overfilled. Levels shall be checked during transfer operations.

(g) The transfer system shall be checked prior to use to ensure that valves are in the correct position. Pressure and temperature conditions shall be observed during the transfer operation, where appropriate.

10.15.3.6.2 Tank Car or Tank Vehicle.

(a) 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.

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

(c) Unless required for transfer operations, truck vehicle engines shall be shut off. Brakes shall be set and wheels checked prior to connecting for unloading or loading. The engine shall not be started until the truck vehicle has been disconnected and any released vapors have dissipated.

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

10.15.4 Maintenance.

10.15.4.1 General.

10.15.4.1.1 Each facility operator shall carry out periodic inspection, tests, or both, as required on every component and its support system in service in its facility.

10.15.4.1.2 Except as provided in this section and 10.15.5.5, the periodic inspections and tests referred to in 10.15.4.1.1 shall be carried out in accordance with generally accepted engineering practice and as often as is necessary to ensure that each component is in good operating condition.

10.15.4.1.3 The support system or foundation of each component shall be inspected at least annually to ensure that the support system or foundation is sound.

10.15.4.1.4 Each emergency power source at the facility shall be tested monthly to ensure that it is operational, and annually to ensure that it is capable of performing at its intended operating capacity.

10.15.4.1.5 Each facility operator shall ensure that 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 is also taken out of service.

10.15.4.1.6 Subparagraph 10.15.4.1.5 shall not apply where the safety function of the device is provided by an alternate means.

10.15.4.1.7 The facility operator shall ensure that 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 thereto, is attached to the controls of the component. When practical, the component shall be locked out.

10.15.4.1.8 Stop valves for isolating pressure or vacuum-relief valves shall be locked or sealed open. They shall not be operated except by an authorized person.

10.15.4.1.9 On each LNG container, no more than one stop valve shall be closed at one time, thus maintaining the relief of 10.12.4.1.

10.15.4.2 Maintenance Manual.

10.15.4.2.1 Each facility operator shall prepare a written manual that sets out an inspection and maintenance program for each component that is used in its facility.

10.15.4.2.2 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 10.15.4.1.1 and 10.15.4.1.2
(2) A description of any other action in addition to those referred to in 10.15.4.2.2(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

10.15.4.2.3 Each facility operator shall conduct its maintenance program in accordance with its written manual for facility components.

10.15.4.3 Site Housekeeping.

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

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

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

10.15.4.3.4 Each facility operator shall ensure that fire-control access routes within its facility are unobstructed and reasonably maintained in all weather conditions.

10.15.4.4 Repairs. Repairs that are carried out on components of its facility shall be carried out in a manner that ensures the following:

(1) The integrity of the components is maintained, in accordance with this standard.
(2) Components will operate in a safe manner.
(3) The safety of personnel and property during a repair activity is maintained.

10.15.4.5 Control Systems, Inspection, and Testing. Each facility operator 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.

(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 code. The following shall also apply:

(1) Monitoring equipment shall be maintained in accordance with ANSI/NFPA 72, *National Fire Alarm 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 the applicable NFPA 13, *Standard for the Installation of Sprinkler Systems*; NFPA 14, *Standard for the Installation of Standpipe, Private Hydrant, 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*; and NFPA 24, *Standard for the Installation of Private Fire Service Mains and Their Appurtenances*.
(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 9, within an LNG facility and on tank vehicles. These extinguishers shall be maintained in accordance with NFPA 10.
(4) Fixed fire extinguishers and other fire-control systems that are installed shall be maintained in accordance with ANSI/NFPA 11, *Standard for Low-Expansion Foam*; NFPA 11A, *Standard for Medium- and High-Expansion Foam Systems*; 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 two 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.

10.15.4.6 Corrosion Control. Each facility operator shall ensure that the requirements of 11.5.6 are met, if applicable.

10.15.4.7 Records.

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

10.15.4.7.2 A record that is required to be kept under 10.15.4.7.1 shall be retained for as long as the facility is in service.

10.15.5 Training.

10.15.5.1 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 10.15.3.3 and providing first aid
(2) Permanent maintenance, operating, and supervisory personnel with respect to 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 upon 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 10.15.3 and 10.15.4;
    d. The LNG transfer procedures set out in 10.15.4
    e. Fire prevention, including familiarization with the fire control plan of the facility, fire fighting, the potential causes of fire in a facility, the types, sizes, and likely consequences of a fire at a facility
    f. Recognizing situations in which it is necessary for the person to obtain assistance in order to maintain the security of the facility

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

10.15.5.3 The plans referred to in 10.15.5.2 shall provide for training sessions to update personnel at intervals that do not exceed two years.

10.15.5.4 Every facility operator shall maintain a record for each applicable employee of its facility that sets out the training given to the employee under this section.

10.15.5.5 A record that is required to be maintained under 10.15.5.4 shall be kept for at least two years after the date that the employee ceases to be employed at the facility.

10.15.5.6 Each facility operator shall ensure the following:

(1) Facility personnel receive applicable training referred to in 10.15.5
(2) Facility personnel have experience related to their assigned duties.

10.15.5.7 Any person who has not completed the training or received experience set out in 10.15.5 shall be under the control of trained personnel.

Chapter 11 Operating, Maintenance, and Personnel Training

11.1* General. Each operating company shall develop documented operating, maintenance, and training procedures based on experience, knowledge of its LNG plants, and conditions under which they will be operated. This section contains basic requirements and minimum standards for the safety aspects of the operation and maintenance of LNG plants, as well as personnel training.

11.2 Basic Requirements. Each operating company shall meet the following requirements:

(1) Have documented procedures covering operation, maintenance, and training
(2) Maintain drawings, charts, and records of plant equipment
(3) Revise the plans and procedures as experience dictates and as changes in operating conditions or plant equipment require
(4) Establish a documented 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 conditions for the purpose of determining their causes and preventing the possibility of recurrence

11.3 Documentation of Operating Procedures.

11.3.1 Manual of Operating Procedures. Each operating company shall have a manual of operating procedures based on experience, knowledge of facilities and fluids being handled, good engineering practices, and safety. The operating company shall operate all components in accordance with the manual. The manual shall be accessible to all plant personnel and shall be kept readily available in the operating control room. It shall be updated as required by changes in equipment or procedures.

11.3.2 Manual Contents. The manual shall include procedures for the following:

(1) The proper startup and shutdown of all components of the plant, including those for an initial startup of the LNG plant that will ensure that all components operate satisfactorily
(2) Purging components and making components inert according to the requirements of 11.3.6

(3) Ensuring the cooldown of components in accordance with the requirements of 11.3.5
(4) Ensuring that each control system is properly adjusted to operate within its design limits
(5) In the case of liquefaction, maintain the temperatures, levels, pressures, pressure differentials, and flow rates for the following:
   a. Boilers
   b. Turbines and other prime movers
   c. Pumps, compressors, and expanders
   d. Purification and regeneration equipment
   e. Equipment within cold boxes, within their design limits, as the case requires
(6) Maintaining the vaporization rate, temperature, and pressure so that the resultant gas is within the design tolerance of the vaporizer and the downstream piping
(7) Determining the existence of any abnormal conditions, and the response to these conditions in the plant, in accordance with the requirements of Chapter 11
(8) Ensuring the safety of personnel and property while repairs are carried out, whether or not equipment is in operation
(9) Ensuring the safe transfer of hazardous fluids, as detailed in Section 8.4
(10) Ensuring security at the LNG plant
(11) Anticipating and responding to emergencies at the LNG plant and the locations where such emergencies can occur
(12) Ensuring that the maximum filling volume of an LNG container is in accordance with 4.1.6
(13) Monitoring operation in accordance with 11.3.4

11.3.3 Emergency Procedures. The types of emergencies referred to under 11.3.2(11) shall include, at a minimum, those 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. Consideration shall include but not be limited to the following:

(1) Procedures for responding to controllable emergencies, including the notifying 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 achieve the following:
   a. Minimize harm to the personnel at the LNG plant and to the public
   b. Provide prompt notification of the emergency to the appropriate local officials, including the possible need to evacuate persons from the vicinity of the LNG plant
(3) Procedures for coordinating with the appropriate 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

11.3.3.1 The procedures and steps of 11.3.3 shall include methods of advising the appropriate local offices of 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

11.3.3.2 Normally, gas fires (including LNG) should not be extinguished until the fuel source has been shut off, unless the fire would create more of a hazard than the gas dispersion.

11.3.4 Monitoring Operation.

11.3.4.1 Operation monitoring shall be carried out by watching or listening for warning alarms from an attended control center and by conducting inspections at least at the intervals set out in the written operating procedures referred to in Section 11.3, and at a minimum on a weekly basis.

11.3.4.2 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.

11.3.5 Cooldown Procedure.

11.3.5.1 Each operating company shall ensure that the cooldown of each system of components that is under its 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, having regard to the performance of expansion and contraction devices.

11.3.5.2 Each operating company shall check each cryogenic piping system under its control during and after cooldown stabilization for leaks in areas where there are flanges, valves, and seals.

11.3.6 Purging. The temperature of the purge gas or liquid shall be at or above the minimum design temperature of the container.

11.3.6.1 General. 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.

11.3.6.2 Container Purging Procedures.

(a)*Several methods are used for purging large containers into and out of service. This standard does not restrict constructors or operators to any one technique. Only experienced personnel trained in accordance with Section 11.6 shall be responsible for such activities.

(b) Before an LNG container is put into service, the air shall be displaced by an acceptable purging method.

(c)*Before a container is taken out of service, the natural gas in the container shall be purged from the container in a safe manner by an acceptable purging method.

(d) During purging operations, the oxygen content of the container shall be determined by the use of an acceptable oxygen analyzer.

11.3.6.3 Purging of Piping Systems. Systems shall be purged of air or gas in a safe manner. *(See 6.7.2.)*

11.3.7 Product Transfer. Where making bulk transfers into stationary storage containers, the LNG being transferred shall meet either of the following requirements:

(a) The LNG shall be compatible in composition or temperature and density with the LNG already in the container.

(b) Where the composition or temperature and density are not compatible, means shall be taken to prevent stratification, which might result in "rollover" and an excessive rate of vapor evolution. If a mixing nozzle or agitation system is provided, it shall be designed to have sufficient energy to accomplish its purpose.

11.3.8 Record Keeping. Each LNG plant operator shall maintain a record of each inspection, test, and investigation required by this subsection. These records shall be retained for at least 5 years.

11.4 Marine Shipping and Receiving.

11.4.1 General Cargo. General cargo, other than ship's stores for the LNG tank vessel, shall not be handled over a pier or dock within 100 ft (30 m) of the point of transfer connection while LNG or flammable fluids are being transferred through piping systems. Ship bunkering shall be permitted if that bunkering is from a pipeline rather than from a barge.

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

11.4.3 Cargo Transfer. 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 the proper operating condition. Following this inspection, they shall meet and determine the transfer procedure, verify that adequate ship-to-shore communications exist, and review emergency procedures.

11.4.4 Tank Vehicle and Tank Car Loading and Unloading Facilities. Transfer shall be made only into tank cars approved for the specific service.

11.4.5 Loading or Unloading Operations.

11.4.5.1 General.

(a) At least one qualified person shall be in constant attendance while loading or unloading is in progress.

(b) Written procedures shall be available to cover all transfer operations and shall cover emergency as well as normal operating procedures. They shall be kept up-to-date and available to all personnel engaged in transfer operations.

(c) Sources of ignition, such as welding, flames, and unclassified electrical equipment, shall not be permitted in loading or unloading areas while transfer is in progress.

(d) Loading and unloading areas shall be posted with signs that read "No Smoking."

(e) 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.

(f) Prior to transfer, gauge readings shall be obtained or inventory established to ensure that the receiving vessel cannot be overfilled. Levels shall be checked during transfer operations.

(g) The transfer system shall be checked prior to use to ensure that valves are in the correct position. Pressure and temperature conditions shall be observed during the transfer operation.

(h) The transfer system shall be checked prior to use to ensure that valves are in the correct position for transfer. Transfer operations shall be commenced slowly; if any unusual variance in pressure or temperature occurs, transfer shall be stopped until the cause has been determined and corrected. Pressure and temperature conditions shall be observed during the transfer operation.

11.4.5.2 Tank Car or Tank Vehicle.

(a) 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.

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

(c) Unless required for transfer operations, truck vehicle engines shall be shut off. Brakes shall be set and wheels checked prior to connecting for unloading or loading. The engine shall not be started until the truck vehicle has been disconnected and any released vapors have dissipated.

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

(e) Prior to loading or unloading, a tank vehicle shall be positioned so that it can exit the area without backing up when the transfer operation is complete.

(f) Tank cars and tank vehicles that are top-loaded through an open dome shall be bonded electrically to the fill piping or grounded prior to opening the dome.

11.4.6 Communications and Lighting. 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.

11.5 Maintenance.

11.5.1 General.

11.5.1.1 Each operating company shall carry out periodic inspection, tests, or both, as required on every component and its support system that is in service in its LNG plant.

11.5.1.2 Except as provided in this paragraph and 11.5.6.5, the periodic inspections and tests referred to in 11.5.1.1 shall be carried out in accordance with generally accepted engineering practice and as often as is necessary to ensure that each component is in good operating condition.

11.5.1.3 The support system or foundation of each component shall be inspected at least annually to ensure that the support system or foundation is sound.

11.5.1.4 Each emergency power source at the LNG plant shall be tested monthly to ensure that it is operational and annually to ensure that it is capable of performing at its intended capacity.

11.5.1.5 The annual test for capacity of an emergency power source shall take into account the power needed to start up some and simultaneously operate other equipment that would have to be served by the power source in an emergency at the LNG plant.

11.5.1.6 Each operating company shall ensure that 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 is also taken out of service.

11.5.1.7 Paragraph 11.5.1.6 shall not apply where the safety function of the device is provided by an alternate means.

11.5.1.8 The operating company shall ensure that, 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 thereto, is attached to the controls of the component. When practical, the component shall be locked out.

11.5.1.9 Stop valves for isolating pressure or vacuum-relief valves shall be locked or sealed open. They shall not be operated except by an authorized person.

11.5.1.10 On each LNG container, no more than one stop valve shall be closed at one time, thus maintaining the relief of 4.7.3.

11.5.1.11 The operating company shall ensure that insulation systems for impounding surfaces are annually inspected to ensure that they are suitable for their intended service.

11.5.2 Maintenance Manual.

11.5.2.1 Each operating company shall prepare a written manual that sets out an inspection and maintenance program for each component that is used in its LNG plant.

11.5.2.2 The maintenance manual for LNG plant components shall include the following:

(1) The manner of carrying out and the frequency of the inspections and tests referred to in 11.5.1.1
(2) A description of any other action, in addition to those referred to in 11.5.2.2(1), 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

11.5.2.3 Each operating company shall conduct its maintenance program in accordance with its written manual for LNG plant components.

11.5.3 Site Housekeeping.

11.5.3.1 Each operating company shall keep the grounds of its LNG plant free from rubbish, debris, and other materials that could present a fire hazard.

11.5.3.2 Each operating company shall ensure that the presence of foreign material contaminants or ice is avoided or controlled to maintain the operational safety of each LNG plant component.

11.5.3.3 Each operating company shall maintain the grassed area of its LNG plant so that it does not create a fire hazard.

11.5.3.4 Each operating company shall ensure that fire control access routes within its LNG plant are unobstructed and reasonably maintained in all weather conditions.

11.5.4 Repairs. Repairs that are carried out on components of an LNG plant shall be carried out in a manner that ensures the following:

(1) The integrity of the components is maintained, in accordance with this standard.
(2) Components operate in a safe manner.
(3) The safety of personnel and property during a repair activity is maintained.

11.5.5 Control Systems, Inspection, and Testing.

11.5.5.1 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.

(a) Each operating company 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 LNG plant shall be inspected and tested in accordance with the applicable fire code. The following shall also apply:

(1) Monitoring equipment shall be maintained in accordance with ANSI/NFPA 72, *National Fire Alarm 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 the applicable ANSI/NFPA 13, *Standard for the Installation of Sprinkler Systems*; NFPA 14, *Standard for the Installation of Standpipe, Private Hydrant, 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*; and NFPA 24, *Standard for the Installation of Private Fire Service Mains and Their Appurtenances*.
(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 9, within an LNG facility and on tank vehicles. These extinguishers shall be maintained in accordance with ANSI/NFPA 10, *Standard for Portable Fire Extinguishers*.
(4) Fixed fire extinguishers and other fire control equipment shall be maintained in accordance with ANSI/NFPA 11, *Standard for Low-Expansion Foam*; NFPA 11A, *Standard for Medium- and High-Expansion Foam Systems*; 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*.

(d) Control systems, other than those referred to in 11.5.5.1(b) and (c), shall be inspected and tested once each calendar year at intervals that do not exceed 15 months.

(e) Stationary LNG tank relief valves shall be inspected and set point tested at least once every two calendar years, with intervals not exceeding 30 months, to ensure that each valve relieves at the proper setting. 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.

(f) 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

(g) 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.

(h) 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 reestablished.

11.5.6 Corrosion Control.

11.5.6.1 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 6.9
(2) Inspection and replacement or repair under a program of scheduled maintenance in accordance with the manual referred to under 11.5.2

11.5.6.2 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.

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

11.5.6.4* Every operating company shall monitor the corrosion control provided under this section as follows:

(a) 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.

(b) Each cathodic protection rectifier or impressed current system shall be inspected at least six times each calendar year at intervals that do not exceed $2^1/_2$ months to ensure that it is operating properly.

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

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

(e) 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. Internal corrosion control monitoring devices shall be checked at least two times each calendar year at intervals not exceeding $7^1/_2$ months.

Exception: Where the component will not be adversely affected by internal corrosion during the time that the component will be in use in the LNG plant.

11.5.6.5 Each operating company that discovers by inspection or otherwise that corrosion is not being controlled at its LNG plant shall take such action as is necessary to control or monitor the corrosion.

11.5.7 Records.

11.5.7.1 Each operating company shall maintain 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 for a period of not less than 5 years. Records shall be made available during business hours upon reasonable notice.

11.5.7.2 Each LNG plant operator shall maintain records of each test, survey, or inspection required by this standard in sufficient detail to demonstrate the adequacy of corrosion control measures for the life of the LNG facility.

11.6 Training.

11.6.1 Every operating company shall develop, implement, and maintain a written training plan to instruct all LNG plant personnel with respect to the following:

(1) Carrying out the emergency procedures that relate to their duties at the LNG plant as set out in the procedure manual referred to in 11.3.3 and providing first aid
(2) Permanent maintenance, operating, and supervisory personnel with respect to the following:
    a. The basic operations carried out at the LNG plant
    b. 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 upon contact with LNG or cold refrigerants
    c. The methods of carrying out their duties of maintaining and operating the LNG plant as set out in the manual of operating and maintenance procedures referred to in Sections 11.5 and 11.3
    d. The LNG transfer procedures set out in Section 11.4
    e. Fire prevention, including familiarization with the fire control plan of the LNG plant; fire fighting; the potential causes of fire in an LNG plant; the types, sizes, and likely consequences of a fire at an LNG plant
    f. Recognizing situations when it is necessary for the person to obtain assistance in order to maintain the security of the LNG plant

11.6.2 Each operating company shall develop, implement, and maintain a written plan to keep personnel of its LNG plant up-to-date on the function of the systems, fire prevention, and security at the LNG plant.

11.6.3 The plans referred to in 11.6.2 shall provide training sessions to update personnel at intervals that do not exceed 2 years.

11.6.4 Every operating company shall maintain a record for each employee of its LNG plant that sets out the training given to the employee under this section.

11.6.5 A record that is required to be maintained under 11.6.4 shall be kept for at least 2 years after the date that the employee ceases to be employed at the LNG plant.

11.6.6 Each operating company shall ensure that LNG plant personnel meet the following requirements:

(a) LNG plant personnel shall receive applicable training referred to in Section 11.6.

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

11.6.7 Any person who has not completed the training or received experience set out in Section 11.6 shall be under the control of trained personnel.

Chapter 12 Referenced Publications

12.1 The following documents or portions thereof are referenced within this standard as mandatory requirements and shall be considered part of the requirements of this standard. The edition indicated for each referenced mandatory document is the current edition as of the date of the NFPA issuance of this standard. Some of these mandatory documents might also be referenced in this standard for specific informational purposes and, therefore, are also listed in Appendix E.

12.1.1 NFPA Publications. National Fire Protection Association, 1 Batterymarch Park, P.O. Box 9101, Quincy, MA 02269-9101.

NFPA 10, *Standard for Portable Fire Extinguishers*, 1998 edition.

NFPA 11, *Standard for Low-Expansion Foam*, 1998 edition.

NFPA 11A, *Standard for Medium- and High-Expansion Foam Systems,* 1999 edition.

NFPA 12, *Standard on Carbon Dioxide Extinguishing Systems,* 2000 edition.

NFPA 12A, *Standard on Halon 1301 Fire Extinguishing Systems,* 1997 edition.

NFPA 13, *Standard for the Installation of Sprinkler Systems,* 1999 edition.

NFPA 14, *Standard for the Installation of Standpipe, Private Hydrant, and Hose Systems,* 2000 edition.

NFPA 15, *Standard for Water Spray Fixed Systems for Fire Protection,* 1996 edition.

NFPA 16, *Standard for the Installation of Foam-Water Sprinkler and Foam-Water Spray Systems,* 1999 edition.

NFPA 17, *Standard for Dry Chemical Extinguishing Systems,* 1998 edition.

NFPA 20, *Standard for the Installation of Stationary Pumps for Fire Protection,* 1999 edition.

NFPA 22, *Standard for Water Tanks for Private Fire Protection,* 1998 edition.

NFPA 24, *Standard for the Installation of Private Fire Service Mains and Their Appurtenances,* 1995 edition.

NFPA 30, *Flammable and Combustible Liquids Code*, 2000 edition.

NFPA 37, *Standard for the Installation and Use of Stationary Combustion Engines and Gas Turbines*, 1998 edition.

NFPA 54, *National Fuel Gas Code*, 1999 edition.

NFPA 58, *Liquefied Petroleum Gas Code*, 2001 edition.

NFPA 59, *Utility LP-Gas Plant Code*, 2001 edition.

NFPA 70, *National Electrical Code®*, 1999 edition.

NFPA 72, *National Fire Alarm Code®*, 1999 edition.

NFPA *101®*, *Life Safety Code®*, 2000 edition.

NFPA 255, *Standard Method of Test of Surface Burning Characteristics of Building Materials*, 2000 edition.

NFPA 385, *Standard for Tank Vehicles for Flammable and Combustible Liquids*, 2000 edition.

NFPA 600, *Standard on Industrial Fire Brigades*, 2000 edition.

NFPA 1221, *Standard for the Installation, Maintenance, and Use of Emergency Services Communications Systems*, 1999 edition.

NFPA 1901, *Standard for Automotive Fire Apparatus*, 1999 edition.

12.1.2 Other Publications.

12.1.2.1 ACI Publications. American Concrete Institute, P.O. Box 9094, Farmington Hills, MI 48333.

ACI 301, *Specifications for Structural Concrete*, 1999.

ACI 304.6R, *Guide for Measuring, Mixing, Transportation and Placing of Concrete*, 1991.

ACI 311.4R, *Guide for Concrete Inspection*, 2000.

ACI 318, *Building Code Requirements for Reinforced Concrete*, 1999.

ACI 318R, *Building Code Requirements for Structural Concrete*, 1999.

ACI 344R-W, *Design and Construction of Circular Wire and Strand Wrapped Prestressed Concrete Structures*, 1988.

ACI 372R, *Design and Construction of Circular Wire- and Strand-Wrapped Prestressed Concrete Structures*, 1997.

ACI 373R, *Design and Construction of Circular Prestressed Concrete Structures with Circumferential Tendons*, 1997.

ACI 506.2, *Specification for Materials, Proportioning, and Application of Shotcrete*, 1995.

12.1.2.2 API Publications. American Petroleum Institute, 1220 L Street NW, Washington, DC 20005.

API 6D, *Specification for Pipeline Valves*, 1994.

API 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*, 1990.

API 2510, *Design and Construction of Liquefied Petroleum Gas (LPG) Installations*, 1989.

12.1.2.3 ASCE Publication. American Society of Civil Engineers, United Engineering Center, 345 East 47th Street, New York, NY 10017.

ASCE 7, *Minimum Design Loads for Buildings and Other Structures*, 1993.

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

ASME *Boiler and Pressure Vessel Code*, 1992 edition, including Addenda and applicable Code Interpretation Cases.

ASME B 31.3, *Process Piping*, 1996.

ASME B 31.5, *Refrigeration Piping*, 1992.

ASME B 31.8, *Gas Transmission and Distribution Piping Systems*, 1992.

12.1.2.5 ASTM Publications. American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959.

ASTM A 366, *Standard Specification for Steel, Sheet, Carbon, Cold-Rolled, Commercial Quality*, 1991.

ASTM A 416, *Standard Specification for Steel Strand, Uncoated Seven-Wire for Prestressed Concrete*, 1994.

ASTM A 421, *Standard Specification for Uncoated Stress-Relieved Steel Wire for Prestressed Concrete*, 1991.

ASTM A 615, *Specification for Deformed and Plain Billet-Steel Bars for Concrete Reinforcement*, 1995.

ASTM A 722, *Standard Specification for Uncoated High-Strength Steel Bar for Prestressing Concrete*, 1998.

ASTM A 821, *Standard Specification for Steel Wire, Hard Drawn for Prestressing Concrete Tanks*, 1993.

ASTM A 996, *Standard Specification for Rail-Steel and Axle-Steel Deformed Bars for Concrete Reinforcement*, 2000.

ASTM C 33, *Standard Specification for Concrete Aggregates*, 1993.

ASTM E 380, *Standard Practice for Use of the International System of Units (SI)*, 1993.

12.1.2.6 CGA Publications. Compressed Gas Association, Inc., 1725 Jefferson Davis Highway, Arlington, VA 22202-4100.

CGA 341, *Standard for Insulated Cargo Tank Specification for Cryogenic Liquids*, 1987.

CGA S-1.3, *Pressure Relief Device Standards — Part 3 — Compressed Gas Storage Containers*, 1994.

12.1.2.7 CSA Publications. Canadian Standards Association, 178 Rexdale Boulevard, Toronto, Ontario, Canada M9W 13R.

B 51, *Boiler, Pressure Vessel and Pressure Piping Code*, 1997.

National Building Code of Canada, 1995.

CAN 4-S102, *Surface Burning Characteristics of Building Materials and Assemblies*, 1988.

CAN 3-A23.3, *Design of Concrete Structures*, 1994.

CAN 3-A23.4, *Precast Concrete — Materials and Construction/Qualification Code for Architectural and Structural Precast Concrete Products*, 2000.

CAN A 23.1, *Concrete Materials and Methods of Concrete Construction*, 2000.

CSA G 279, *Steel for Prestressed Concrete Tendons*, 1998.

CSA C 22.1, *Canadian Electrical Code*, 1998.

CSA G 30.3, *Cold-Drawn Steel Wire for Concrete Reinforcement*, 1998.

CSA G 30.5, *Welded Steel Wire Fabric for Concrete Reinforcement*, 1998.

CSA G 30.18, *Billet-Steel Bars for Concrete Reinforcement*, 1998.

12.1.2.8 FEMA Publication. Federal Emergency Management Agency, P.O. Box 2012, Jessup, MO 20794.

NEHRP Recommended Provisions for Seismic Regulation for New Buildings and Other Structures, 1997.

12.1.2.9 GRI Publications. Gas Research Institute, 8600 West Bryn Mawr Avenue, Chicago, IL 60631.

GRI Report 96/0396.5, "Evaluation of Mitigation Models for Accidental LNG Releases, Volume 5; Using FEM3A for LNG Accidental Consequence Analysis," 1996.

GRI Report 0176, "LNGFIRE: A Thermal Radiation Model for LNG Fires," 1989.

GRI Report 0242, "LNG Vapor Dispersion Prediction with the DEGADIS Dense Gas Dispersion Model," 1989.

12.1.2.10 ICBO Publication. International Conference of Building Officials, 5360 Workman Mill Road, Whittier, CA 90601.

Uniform Building Code, 1994.

12.1.2.11 NACE Publication. National Association of Corrosion Engineers, 2400 West Loop South, Houston, TX 77027.

NACE RP 0169, *Control of External Corrosion on Underground or Submerged Metallic Piping Systems*, 1992.

12.1.2.12 TEMA Publications. Tubular Exchanger Manufacturers Association standards are available from the Tubular Exchanger Manufacturers Association, 331 Madison Avenue, New York, NY 10017.

12.1.2.13 U.S. Government Publication. U.S. Department of Transportation (DOT), U.S. Government Printing Office, Superintendent of Documents, Mail Stop SSOP, Washington, DC 20402-9328.

12.1.2.14 Referenced Organization. National Board of Boiler and Pressure Vessel Inspectors, 1055 Crupper Avenue, Columbus, OH 43229.

Appendix A Explanatory Material

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 vaporized. Generally, at temperatures below approximately −170°F (−112°C), this gas is heavier than ambient air at 60°F (15.6°C). However, as its temperature rises, it becomes lighter than air.

NOTE 1: The −260°F (−162°C) temperature value is for methane. If the constituents are present, see 1.7.18, Liquefied Natural Gas (LNG).

NOTE 2: For information on the use of LNG as a vehicle fuel, see NFPA 57, *Liquefied Natural Gas (LNG) Vehicular Fuel Systems Code*.

A.1.7.1 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.1.7.2 Authority Having Jurisdiction. The phrase "authority having jurisdiction" 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.2.1.4 See ASCE 56, *Subsurface Investigation for Design and Construction of Foundation for Buildings*, and API 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*, Appendix C, for further information.

A.2.4.3 See ASCE 56, *Subsurface Investigation for Design and Construction of Foundation for Buildings*, and API 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*, Appendix C, for further information.

A.2.5 Soil movement due to freezing of water is of two general types: (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.3.4.4 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.4.1.7.1 The *Canadian Foundation Engineering Manual*, published by the Canadian Geotechnical Society; ASCE 56, *Subsurface Investigation for Design and Construction of Foundation for Buildings*; and Appendix C of API Standard 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*, can be used as guides for this investigation.

A.4.1.7.2(3) It may not be practical to add a cathodic protection system to an existing tank's outer tank bottom. This is due to 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.4.7.3.2 For double-wall, perlite-insulated tanks, this may be the governing criterion for pressure relief valve sizing.

A.4.7.3.4(a) It is the responsibility of the user to determine whether the insulation will resist dislodgment by the available fire fighting equipment and for determining the rate of heat transfer through the insulation when exposed to fire.

A.6.5 For information on identification of piping systems, see ASME A 13.1, *Scheme for the Identification of Piping Systems.*

A.6.7.1 ASME B31.8, *Gas Transmission and Distribution Piping Systems*, paragraph 841.275, can be used as a guide.

A.6.9.1 Title 49 of the U.S. *Code of Federal Regulations*, Part 192, Subpart I, includes corrosion protection requirements.

A.7.7.1 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.7.7.3 For information on stray currents, see API RP 2003, *Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents.*

A.7.7.4 For information on lightning protection, see NFPA 780, *Standard for the Installation of Lightning Protection Systems*, and API RP 2003, *Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents.*

A.8.4.1 For information on operation of piers, docks, and wharves, see NFPA 30, *Flammable and Combustible Liquids Code.*

A.9.1.2 For information on fire extinguishing systems, see the following:

NFPA 10, *Standard for Portable Fire Extinguishers*
NFPA 11, *Standard for Low-Expansion Foam*
NFPA 11A, *Standard for Medium- and High-Expansion Foam Systems*
NFPA 12, *Standard on Carbon Dioxide Extinguishing Systems*
NFPA 12A, *Standard on Halon 1301 Fire Extinguishing Systems*
NFPA 13, *Standard for the Installation of Sprinkler Systems*
NFPA 14, *Standard for the Installation of Standpipe, Private Hydrant, and Hose Systems*
NFPA 15, *Standard for Water Spray Fixed Systems for Fire Protection*
NFPA 16, *Standard for the Installation of Foam-Water Sprinkler and Foam-Water Spray Systems*
NFPA 17, *Standard for Dry Chemical Extinguishing Systems*
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*
NFPA 25, *Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems*
NFPA 68, *Guide for Venting of Deflagrations*
NFPA 69, *Standard on Explosion Prevention Systems*
NFPA 72, *National Fire Alarm Code®*
NFPA 750, *Standard on Water Mist Fire Protection Systems*
NFPA 1961, *Standard on Fire Hose*
NFPA 1962, *Standard for the Care, Use, and Service Testing of Fire Hose Including Couplings and Nozzles*
NFPA 1963, *Standard for Fire Hose Connections*
NFPA 2001, *Standard on Clean Agent Fire Extinguishing Systems*

A.9.1.2(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.9.5.1 Extinguishers of the dry chemical type usually are preferred. Fixed fire extinguishing and other fire control systems can be appropriate for the protection of specific hazards as determined in accordance with 9.1.2.

A.9.7.1 Protective clothing for normal liquid transfer operations should include cryogenic gloves, safety glasses, face shields, and coveralls or long-sleeve shirts.

A.9.7.3 Information concerning confined entry practices and procedures can be found in Title 29, Labor of the U.S. *Code of Federal Regulations*, Part 1910.146 (1-14-93, effective 4-15-93), Canadian Federal Employment & Labor Statutes Part II, and any local, state, or provincial requirements and standards that apply.

A.9.7.4 Natural gas, LNG, and hydrocarbon refrigerants within the process equipment are usually not odorized, and the sense of smell cannot be relied on to detect their presence. Two portable detectors should be available for monitoring when required with a third detector for backup. This provides a spare detector in the event of failure of one of the primary detectors and also allows verification if the two primary detectors provide different readings.

A.9.8 Where gas must be released intermittently or in an emergency, a discharge directed upward at high velocity will safely dissipate the gas. Separate release points can be preferable to collecting the discharge from several relief valves in a common header. An ignited flare is permitted in LNG facilities if local conditions warrant.

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. Lever-operated relief valves often can be used for this purpose.

A.10.6.5 For information on corrosion protection, see NACE RP 0169, *Control of External Corrosion on Underground or Submerged Metallic Piping Systems.*

A.11.1 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, and in some cases impractical.

A.11.2(6) LNG plants under the jurisdiction of the U.S. Department of Transportation under Title 49 of the *Code of Federal Regulations*, Part 193, have a definition of safety-related malfunctions in 49 *CFR* 191.

A.11.3.6.2(a) There are several references covering the purging of large containers. Refer to *Purging, Principles and Practice*, available from the American Gas Association.

A.11.3.6.2(c) 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.

A.11.5.6.4 API RP 651, *Cathode Protection of Aboveground Petroleum Storage Tanks,* provides guidance in the use of cathodic protection.

Appendix B Seismic Design of LNG Plants

This appendix is not a part of the requirements of this NFPA document but is included for informational purposes only.

B.1 Introduction. The purpose of Appendix B is to provide information on the selection and use of operating basis earthquake (OBE) and safe shutdown earthquake (SSE) seismic recurrence levels. These two seismic recurrence 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 operating basis earthquake is a probable earthquake to which the facility may be subjected during its design life. All elements of the facility are designed to withstand this event in accordance with conventional engineering procedures and criteria, and therefore, the facility will remain in operation.

The OBE is identified by a ground motion response spectrum in which the spectral acceleration at any period, *T*, is equal to $^2/_3$ of the spectral acceleration of the MCE ground motion. The MCE ground motion is defined in 4.1.3.1 and is the basis for the seismic zone maps incorporated in the *NEHRP Recommended Provisions for Seismic Regulations for New Buildings and Other Structures.* While the MCE represents a ground motion with a 2 percent probability of exceedance in 50 years, the probability of exceedance for the OBE (that is, $^2/_3$ of the MCE) varies, ranging from about 3 percent to 10 percent in 50 years, depending on the seismic region. This is equivalent to mean recurrence intervals of 1641 to 475 years, respectively. This also represents the level of seismic loading that will form the basis for the design using the appropriate codes and normal stress levels.

B.3 Safe Shutdown Earthquake (SSE).

B.3.1 The safe shutdown earthquake is a rare earthquake of extreme magnitude for the facility location. The facility is designed to contain the LNG and prevent catastrophic failure of critical facilities under this contingency event. Plastic behavior and significant finite movements and deformations, not usually considered in conventional engineering procedures, are possible. The facility is not required to remain operational following the SSE event. Following such an event, the facility is expected to be inspected and repaired as necessary. The SSE is specified as being representative of a seismic ground motion that has a probability of exceedance not greater than 0.02 percent per annum (1 percent in 50 years) but not greater than twice the OBE ground motion.

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 4.1.3.6. 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 OBE level of loading while holding the volume, *V*, as specified in 2.2.2.1. 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. It is assumed that the strength of the aftershock can be reasonably represented by an OBE.

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 without risk to the preceding.

B.3.6 The operator is required to install instrumentation capable of measuring ground motion at the plant site. Following an earthquake producing 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 may prove that the container OBE stress levels are not exceeded.

B.4 Design Response Spectra. Using the OBE and SSE ground motions as defined in B.2 and B.3.1 respectively, vertical and horizontal design response spectra must be constructed covering the entire range of anticipated damping factors and natural periods of vibration, including the damping factor and first-mode sloshing period of vibration of the contained LNG.

B.5 Other Seismic Loads.

B.5.1 Small LNG plants consisting of shop-built LNG containers and limiting processing equipment should be designed for seismic loading using the ground motion specified for the seismic zones adopted by the *NEHRP Recommended Provisions for Seismic Regulations for New Buildings and Other Structures.* Either a structural response analysis should be performed or an amplification factor of 0.60 should be applied to the maximum design spectral acceleration, SDS, as defined in 4.1.3.8 to determine the loads on the vessels or piping.

B.5.2 All other structures, buildings, and process equipment must be designed for seismic loading in accordance with the *NEHRP Recommended Provisions for Seismic Regulations for New Buildings and Other Structures.*