NFPA 59A

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

1996 Edition

National Fire Protection Association, 1 Batterymarch Park, PO Box 9101, Quincy, MA 02269-9101
An International Codes and Standards Organization

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Standard for the Production, Storage, and Handling of

Liquefied Natural Gas (LNG)

1996 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 Fall Meeting held November 13-15, 1995, in Chicago, IL. It was issued by the Standards Council on January 12, 1996, with an effective date of February 2, 1996, and supersedes all previous editions.

Changes other than editorial are indicated by a vertical rule in the margin of the pages on which they appear. These lines are included as an aid to the user in identifying changes from the previous edition.

This edition of NFPA 59A was approved as an American National Standard on February 2, 1996.

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.

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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

NFPA 59A

Standard for the Production, Storage, and Handling of

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NOTICE: An asterik (*) 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 11 and Appendix B.

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

FOREWORD

This standard outlines basic methods of equipment fabrication and installation as well as operating practices for the protection of persons and property and provides guidance to all persons concerned with the construction and operation of equipment for the production, storage, and handling of liquefied natural gas (LNG).

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 containment to the atmosphere, LNG will vaporize and release gas that, at ambient temperature, will have 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 then becomes lighter than air.

NOTE 1: The –170°F (–112°C) temperature value is for methane. If other constituents are present, see definition of Liquefied Natural Gas in Section 1-3.

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

Chapter 1 Introduction

1-1 General.

1-1.1 Alternate Materials and Procedures. It is recognized that advancements in engineering and improvements in equipment can result in equipment fabrication methods and operating practices that differ from those specifically called for in this standard. Yet, such deviations or improvements might provide desirable safety and compatible operation that meet the intent of this standard. Such deviations are acceptable where the authority having jurisdiction has made a special investigation of all factors and, based on sound experience and engineering judgment, concludes that the proposed deviations meet the intent of this standard.

1-1.2 Retroactivity. Where existing plants, equipment, buildings, structures, and installations meet the applicable design, fabrication, or construction layout provisions of the edition of this standard that was in effect at the time of installation, they can be continued in use, provided they do not constitute a distinct hazard to life or adjoining property.

1-1.3 Employees engaged in the production, handling, and storage of liquefied natural gas (LNG) shall be trained in the hazards and properties of LNG.

1-1.4 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.

1-2 Scope.

1-2.1 This standard applies to the design, location, construction, and operation of facilities at any location for the liquefaction of natural gas and the storage, vaporization, transfer, handling, and truck transport of LNG.

1-2.2 This standard covers all containers for the storage of liquefied natural gas containers.

Exception: Frozen ground containers.

1-3 Definitions.

Approved. Acceptable to the authority having jurisdiction.

NOTE: 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 concerned with product evaluations that is in a position to determine compliance with appropriate standards for the current production of listed items.

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

NOTE: NOTE: The phrase "authority having jurisdiction" is used in NFPA documents in a broad manner, since jurisdcitions 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.

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

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

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

Container. A vessel for storing liquefied natural gas.

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

Container, Prestressed Concrete. 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.

Deriming. Deriming, which is synonymous with defrosting or deicing, refers to the removal, by heating and evaporation, sublimation, or solution, of accumulated constituents that form solids, such as water, carbon dioxide, etc., from the low-temperature process equipment.

Design Pressure. The pressure used in the design of equipment, a container, or a vessel for the purpose of determining the minimum permissible thickness or physical characteristics of its different parts. Where applicable, static head shall be included in the design pressure to determine the thickness of any specific part.

Dike. A structure used to establish an impounding area.

Failsafe. Design features that provide for the maintenance of safe operating conditions in the event of a malfunction of control devices or an interruption of an energy source.

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

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.*

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

Ignition Source. Any item or substance capable of an energy release of type and magnitude sufficient to ignite any flammable mixture of gases or vapors that could occur at the site.

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

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

LNG. An abbreviation for "liquefied natural gas."

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

Primary Component. Parts of LNG containers that are stressed to a significant level, those whose failure would allow leakage of the LNG being stored, those exposed to a temperature of –60°F to –270°F (–51°C to –168°C), and those subject to thermal shock. Primary components include, but are not limited to, the following parts of a single-wall tank or of the inner tank in a double-wall tank:

(a) Shell plates;

(b) Bottom plates;

(c) Roof plates;

(d) Knuckle plates;

(e) Compression rings;

(f) Shell stiffeners;

(g) Manways; and

(h) Nozzles, including reinforcement, shell anchors, pipe, tubing, forging, and bolting.

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

Psia. Pounds per square inch absolute.

Psig. Pounds per square inch gage.

Secondary Components. Secondary components, as referred to in Chapter 4, include those that will not be stressed to a significant level, those whose failure will not result in leakage of the LNG being stored, or those exposed to the boiloff gas and having a design metal temperature of –60°F (–51°C) or higher.

Shall. Indicates a mandatory requirement.

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

Transfer Area. That portion of an LNG plant containing piping systems 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 routinely connected or disconnected. Transfer areas do not include product sampling devices or permanent plant piping.

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 usual welding or joining techniques.

Chapter 2 General Plant Considerations

2-1 Plant Site Provisions.

2-1.1 General. Factors to be considered in the selection of plant site locations shall include the following:

(a) At least one all-weather vehicular road shall be provided.

(b) 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.

2-2 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 (*see 2-2.1.3*) in accordance with one of the following methods:

(a) 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; or

(b) 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; or

(c) 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 (*see 2-2.1.3*):

(a) Process areas;

(b) Vaporization areas;

(c) Transfer areas for LNG, flammable refrigerants, and flammable liquids;

(d) 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 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:

(a) For impounding areas serving a single container:

V = the total volume of liquid in the container, assuming the container is full.

(b) 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 = the total volume of liquid in the largest container served, assuming the container is full.

(c) For impounding areas serving more than one container without provision made in accordance with 2-2.2.1(b):

V = 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.

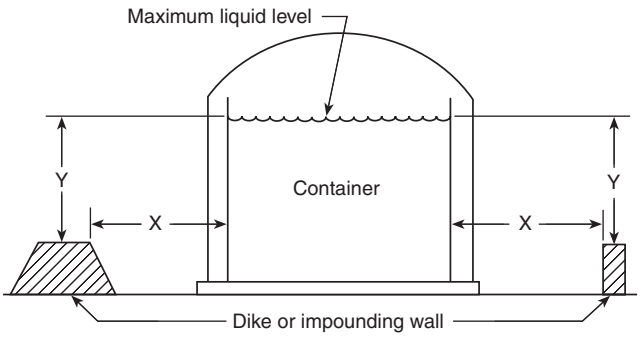
Exception: Container downcomers used to conduct spilled LNG away from critical areas rapidly shall be permitted to be enclosed.

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.

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.



Notes:
- Dimension X shall equal or exceed the sum of dimension Y plus the equivalent head in LP-Gas 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.

Figure 2-2.2.6 Dike or impounding wall proximity to containers.

2-2.2.8 Insulation systems used for impounding surfaces shall be, in the installed condition, noncombustible and intended for the 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 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 2-2.3.3).

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:

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:

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

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

(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 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:

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.

2-2.3.2 Provisions shall be made to minimize the possibility of a flammable mixture of vapors from a design spill specified in 2-2.3.3(a), (b), (c), or (d), 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:

(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; and

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

(c) Are acceptable to the authority having jurisdiction.

(b) The computed distances shall include calculations based upon:

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; or

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 upon 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.

2-2.3.3 The design spill shall be determined in accordance with the following:

(a) For impounding areas serving LNG containers that have penetrations below the liquid level that are not fitted with internal shutoff valves, the design spill shall be defined as flow through an assumed opening at, and equal in area to, that penetration below the liquid level that would result in the largest flow from an initially full container. The flow, as determined by the formula in 2-2.3.3(c), shall be assumed to continue until the differential head acting on the opening is 0 (zero). For impounding areas serving more than one container, the design spill shall be applied to the container that results in the largest flow.

(b) For impounding areas serving LNG containers with "over-the-top" fill and withdrawal connections and that have no tank penetrations below the liquid level, the design spill shall be defined as 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 duration of the design spill shall be 10 minutes, provided demonstrable surveillance and shutdown provisions acceptable to the authority having jurisdiction exist; otherwise, the duration shall be the time needed for the initially full container to empty.

(c) For impounding areas serving LNG containers that have all penetrations below the liquid level fitted with internal shutoff valves in accordance with 6-3.3.3, the design spill shall be defined as 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. The flow shall be the maximum computed from the following formula, with the flow, "q," lasting for 1 hour, provided demonstrable surveillance and shutdown provisions acceptable to the authority having jurisdiction exist; otherwise, the duration shall be the time needed for the initially full container to empty.

$$q = \frac{4}{3} d^2 \sqrt{h}$$

where:

q = the flow rate (ft3/min) of liquid

d = the diameter (in.) of tank penetration below the liquid level

h = the height (ft) of liquid above penetration in the container when the container is full.

(d) For impounding areas serving only vaporization, process, or LNG transfer areas, the design spill shall be defined as flow for 10 minutes from any single accidental leakage source or for a shorter time, based upon demonstrable surveillance and shutdown provisions acceptable to the authority having jurisdiction.

2-2.3.4 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.

2-2.3.5 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:

All connections shall be equipped with automatic failsafe valves. These automatic valves shall be designed to close under any of the following conditions:

(a) Fire detection;

(b) Excess flow of LNG from the container, as measured by loss of line pressure or other means;

(c) Gas detection;

(d) Manual operation from a local and remote location.

Exception No. 1: Relief valves and instrument connection valves.

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 above requirements.

The appurtenances shall be installed as close to the container as practical and so that a break resulting from external strain shall occur 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.

2-2.3.6 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).

2-2.3.7 The provisions of 2-2.3 shall not apply to impounding areas serving only transfer areas at the water's edge of marine terminals.

2-2.4 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.

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.

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)
Less than 125	0.5	0	0	0	0
125 to 500	0.5 to 1.9	10	3	3	1
501 to 2000	1.9 to 7.6	15	4.6	5	1.5
2001 to 15,000	7.6 to 56.8	25	7.6	5	1.5
15,001 to 30,000	56.8 to 114	50	15	5	1.5
30,001 to 70,000	114 to 265	75	23		
Greater than 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]	

Process heaters or other units of fired equipment shall not be considered to be sources of ignition with respect to vaporizer siting, provided 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:

(a) 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.

(b) 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.

(c) 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 as provided in 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(c) 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 In multiple heated vaporizer installations, 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. 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.

2-3.1 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.

2-3.2 The buildings or structural enclosures cited in Section 2-3 shall be ventilated to minimize the possibility of hazardous accumulations of flammable gases or vapors in accordance with 2-3.2.1 through 2-3.2.3.

2-3.2.1 Ventilation shall be permitted to be by means of:

(a) A continuously operating mechanical ventilation system; or

(b) 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; or

(c) A dual rate mechanical ventilation system with the high rate energized by gas detectors in the event flammable gas is detected; or

(d) 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 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 peakshaving applications or for service maintenance during gas systems repair/alteration or for other short-term applications shall be permitted, provided:

(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, boiloff 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 8-7.1.2; 8-7.2.3; Section 8-8; 8-9.1; 9-1.4; 9-1.4.1; 9-1.5; 9-3.1; 9-3.2; 9-3.4, 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 upon a public right-of-way or upon 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 above, 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.

2-4.1.1 Supervision shall be provided for the fabrication of and for the acceptance tests of facility components to the extent necessary to ensure that they are structurally sound and otherwise in compliance with this standard.

2-4.1.2 Sufficient soil and general investigations shall be made to determine the adequacy of the intended site for the facility.

NOTE: 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.

2-4.2 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.

NOTE: 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.

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 paragraph 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 but 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 Systems

3-1 General. Process system equipment containing LNG, flammable refrigerants, or flammable gases shall be:

(a) Installed outdoors for ease of operation to facilitate manual fire fighting and to facilitate dispersal of accidentally released liquids and gases; or

(b) Installed indoors in enclosing structures complying with 2-3 and 2-3.2.

3-2 Pumps and Compressors.

3-2.1 Pumps and compressors shall be constructed of materials intended for the temperature and pressure conditions that can be encountered.

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.

Exception: Where casing and downstream piping and equipment are designed for the maximum discharge pressure of the pumps and compressors.

3-2.4 Each pump shall be provided with an adequate vent or relief valve, or both, that prevents overpressuring the pump case during the maximum possible rate of cool-down.

3-2.5 The foundations and sumps for cryogenic pumps shall be designed and constructed to prevent frost heaving.

3-2.6 Pumps used for transfer of liquids at temperatures below –20°F (–29°C) shall be provided with means for precooling to ensure that the pumps are not damaged or made temporarily or permanently inoperable.

3-2.7 Compression equipment that handles flammable gases shall be provided with vents from all points, including distance pieces, where gases normally can escape. Vents shall be piped outside of buildings to a point of safe disposal.

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, *Standard for the Storage and Handling of Liquefied Petroleum Gases*; NFPA 59A, *Standard for the Storage and Handling of Liquefied Petroleum Gases at Utility Gas Plants*; 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, 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, 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, where such components fall within the jurisdiction of the 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*.

NOTE: 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.*

3-4.5 A boiloff 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. Boiloff and flash gases shall discharge safely into the atmosphere or into a closed system. The boiloff 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.

3-4.7* Equipment Depressurizing.

3-4.7.1 Emergency controls to effect the depressurization shall be marked conspicuously with their designated function, and they shall be accessible under emergency conditions.

3-4.7.2 The discharge of flammable gases or liquids from relief devices shall be directed into a closed system or to a point of safe disposal. Flammable gases shall be permitted to be discharged directly to atmosphere. (*See Section 4-8.*)

3-4.8 Cold Boxes.

3-4.8.1 A cold box structure and its contents shall be constructed of materials that do not support combustion.

3-4.8.2 Cold boxes shall be purged in accordance with Section 4-6, treating the cold box as a container. If a flammable mixture is detected within the cold box at any time, purge gas shall be introduced until the mixture is outside of the flammable range.

3-4.9 Salt bath heaters shall be installed within curbed areas, or other means shall be provided to retain spillage of molten salt.

3-5 Air Injection. In those cases where air can be injected into the plant inlet natural gas stream, provision shall be made to prevent a flammable mixture from occurring under any operating condition.

3-6 Relief Devices. Process equipment that can be overpressured shall be protected by a safety relief valve(s) providing a sufficient rate of discharge to prevent pressures exceeding those permitted by the governing code, giving proper consideration to fire exposure, process upsets, or loss of utilities.

3-7 Process Equipment Supports. Where the structural stability of process equipment is essential to plant safety, the supports for the equipment shall be resistant to or protected against fire exposure or cold liquid, or both, if they are subject to such exposures.

Chapter 4 Stationary LNG Storage Containers

4-1 General.

4-1.1 Inspection.

4-1.1.1 Prior to initial operation, containers shall be inspected to ensure compliance with the engineering design and material, fabrication, assembly, and test provisions of this standard. The operator shall be responsible for this inspection.

4-1.1.2 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.

4-1.2 Basic Design Considerations.

4-1.2.1 Those parts of LNG containers that normally are in contact with LNG and all materials used in contact with LNG or cold LNG vapor [vapor at a temperature below –20°F (–29°C)] shall be physically and chemically compatible with LNG and intended for service at –270°F (–168°C).

4-1.2.2 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 B31.3, *Chemical Plant and Petroleum Refinery 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."

4-1.2.3 All LNG containers shall be designed to accommodate both top and bottom filling unless other positive means are provided to prevent stratification. (*See 8-1.3.*)

4-1.2.4 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.

4-1.2.5 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.

4-1.2.6 The density of the liquid shall be assumed to be the actual weight per ft^3(m^3) at the minimum storage temperatures. In no case shall the assumed density be less than 29.3 lb/ft^3 (470 kg/m^3).

4-1.2.7 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. The operator shall perform a site investigation to determine the seismic potential and resulting response spectra for all installations except those provided for in 4-1.3.8. Investigations shall be conducted to obtain pertinent geotechnical information concerning the geologic and seismic characteristics of the LNG facility and the surrounding region.

4-1.3.2 The investigation shall include:

(a) The detection and identification of surface faulting at the specific site and the potential for such faulting.

(b) The characteristics of the materials underlying the site as they relate to the transmission of vibratory motion from bedrock through the soil if the facility is not grounded on rock, as well as the potential for soil liquefaction and degradation.

(c) The determination of vertical and horizontal response spectra correlating the acceleration, velocity, and displacement with the seismic characteristics of the soil and damping factors of the structural systems in the range of anticipated natural periods of vibration.

4-1.3.3 The investigation shall determine the safe shutdown earthquake (SSE) and operating basis earthquake (OBE), which shall be defined as follows:

(a) Probabilistically, where ground motions are produced with a mean recurrence interval of 10,000 years for the SSE and 475 years for the OBE; or

(b) Deterministically, in regions where the uncertainties are difficult to quantify because of the lack of geological data, where the SSE is the event that produces the maximum credible ground motion at the site based upon the seismology, geology, and seismic and geologic history of the site and region, and where the ground motions for the OBE are $^1/_2$ those determined for the SSE.

4-1.3.4 The following structures and systems shall be designed to comply with 4-1.3.3:

(a) An LNG container and its impounding system;

(b) System components required to isolate the LNG container and maintain it in a safe shutdown condition;

(c) Fire protection systems.

4-1.3.5 An LNG container shall be designed for the OBE and a stress limit check shall be made for the SSE. Stresses under the OBE shall be in accordance with the code or standard applicable to the container as specified in this standard. Stresses under the SSE shall be subjected to the following limits:

(a) In metal containers, stresses shall not exceed yield for the tensile condition and shall not exceed critical for the buckling condition where including the effect of liquid pressure on buckling stability.

(b) In prestressed concrete containers, axial hoop stresses from unfactored loads shall not exceed the modulus of rupture for the tensile condition and shall not exceed 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 shall not exceed 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 shall not exceed 94 percent of the yield stress in prestressed reinforcement, with the assumption of a cracked section.

The LNG container shall be designed to remain operable during and after an OBE. Similarly, the design shall be such that, during and after an SSE, there shall be no loss of containment capability, and it shall be possible to isolate and maintain the LNG container.

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

4-1.3.6 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 SSE, there shall be no loss of containment capability.

4-1.3.7* The dynamic analysis of the LNG container and associated structural components shall include the effects of liquid sloshing and restrained liquid. Tank flexibility, including shear deformation, shall be included in the determination of the significant tank frequencies. For containers supported by pile caps, the flexibility of the pile system shall be considered.

4-1.3.8 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:

(a) Horizontal force $V = Z_c \times W$

where:

Z_c = the seismic coefficient from Table 4-1.3.8

W = the total weight of the container and its contents.

(b) Design vertical force $P = {}^2/_3 \times Z_c \times W$

(c) The seismic coefficient shall be permitted to be calculated in accordance with the nonbuilding structures provisions of the *Uniform Building Code*, using an Importance Factor I of 1.25. The minimum coefficient from Table 4-1.3.8 shall be used if the natural period of vibration, "T," is less than 0.3 seconds.

Table 4-1.3.8 Seismic Coefficient for Shop-Built Containers

Zone	Coefficient (Z_c)	Effective Peak Horizontal Acceleration (EPA) (%G)
1	0.09	7.5
2A	0.17	15.0
2B	0.23	20.0
3	0.34	30.0
4	0.46	40.0

NOTE 1: Source: *Uniform Building Code* seismic zone map.
NOTE 2: The EPA (%G) is equivalent to the seismic zones and can be used to determine Z_c in areas where seismic zones are not available.

4-1.3.8.1 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.

4-1.3.8.2 The requirements of this section shall apply to ASME containers built prior to July 1, 1996, when reinstalled.

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.

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 water-free, 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 Section 1-3 for definition of 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; and

(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; and

(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; and

(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.

4-1.6.1* The maximum filling volume of an LNG container shall be in accordance with Figure 4-1.6.1. The liquid capacity is the volume of liquid measured when a container is filled to its maximum permitted level.

Example: The relief valve of a container designed for a maximum allowable working pressure of 65 psi is set at 65 psi. After filling, the gas pressure at the top is 20 psi. As determined from Figure 4-1.6.1, the maximum filling volume is 94.3 percent of the liquid capacity.

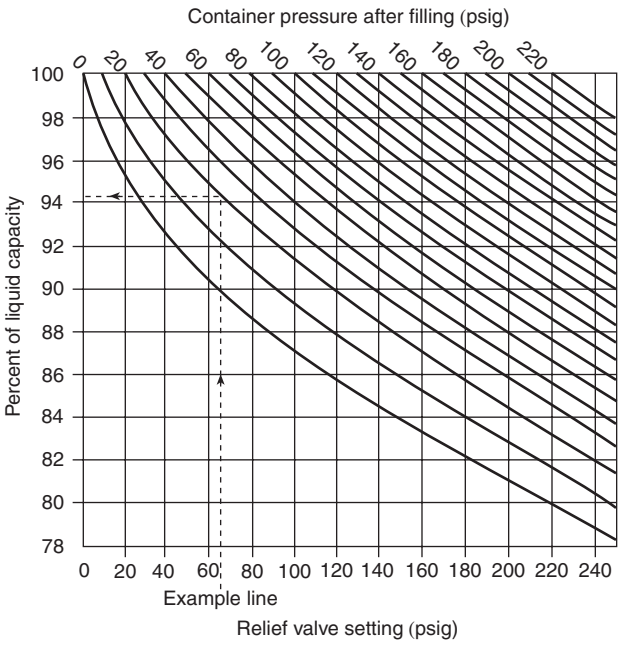


Figure 4-1.6.1 Maximum filling volume for pressure containers.

4-1.6.2 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, and the material in contact with the bottom of the outer tank shall be selected to minimize corrosion.

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, then the bottom of the outer tank shall be of a material compatible with the temperatures to which 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 (OBE) (*see 4-1.3.3*), 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.

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 paragraph Q-7.6.5, change "twenty-five percent" to "all."

(b) In paragraphs 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, paragraph C.11, shall be considered 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 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.

(a) Any of the materials authorized for service at –270°F (–168°C) by the ASME *Boiler and Pressure Vessel Code* shall be permitted.

(b) In the case of vacuum insulation, the design pressure shall be the sum of the required working pressure, 15 psig (100 kPa) 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.

(c) The inner tank shall be designed for the most critical combination of loadings resulting from internal 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 the 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 either by:

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); or

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 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.

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.

4-2.2.6 The inner tank shall be supported essentially concentrically within the outer tank by either a metallic or a nonmetallic system that is capable of sustaining the maximum loading as follows:

(a) For shipping loads, the supports shall be designed for the maximum number of Gs (*see Section 1-3 for definition*) to be encountered multiplied by the empty weight of the inner tank.

(b) For operating loads, the supports shall be designed for the total weight of the inner tank and its contents. Seismic factors shall be included. The weight of contained liquid shall be based upon the maximum density of the specified liquid within the range of operating temperatures, except that the minimum density shall be at least 29.3 lb/ft^3 (470 kg/m^3).

4-2.2.7 The allowable design stress in inner tank support members shall be $^1/_3$ of the tensile strength or $^5/_8$ of the yield strength, whichever is lower, 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 applies 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 comply with, ACI 318, *Building Code Requirements for Reinforced Concrete*, and shall be in accordance with 4-3.2.2, 4-3.2.3, and 4-3.2.4.

NOTE: For additional information, see ACI 344R-W, *Design and Construction of Circular Wire and Strand Wrapped Prestressed Concrete Structures.*

4-3.2.2 The allowable stresses for normal design considerations shall be based upon room temperature 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 those specified in Table 4-3.2.3.

Table 4-3.2.3 Maximum Allowable Stresses for Carbon Steel Reinforcing Bars

#4 and smaller	12,000 psi (82.7 MPa)
#5, #6, and #7	10,000 psi (68.9 MPa)
#8 and larger	8000 psi (55.2 MPa)

Tensile stresses inclusive of direct temperature and shrinkage effects shall not exceed the yield strength of the reinforcement.

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 specified in Table 4-3.2.4.

Table 4-3.2.4 Maximu Maximum Allowable Stresses for Steel Wire or Strands

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

4-3.2.5 External forces imposed upon 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 as specified by ACI 304R, *Guide for Measuring, Mixing, Transportation and Placing of Concrete*, and ACI 318, *Building Code Requirements for Reinforced Concrete*, concerning construction requirements, specifications, and tests.

Tests 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 as specified by ASTM C 33, *Standard Specification for Concrete Aggregates*. 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 as specified in ACI 506R, *Guide to Shotcrete*.

4-3.3.4 High tensile strength elements for prestressed concrete shall be as specified by ASTM A 227, *Standard Specification for Steel Wire, Cold—Drawn for Mechanical Springs*; ASTM A 416, *Standard Specification for Steel Strand, Uncoated Seven-Wire for Prestressed Concrete*; ASTM A 421, *Standard Specification for Uncoated Stress-Relieved Steel Wire for Prestressed Concrete*; and ASTM A 821, *Standard Specification for Steel Wire, Hard Drawn for Prestressing Concrete Tanks*. 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*, or any materials 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 in ASTM A 82, *Standard Specification for Steel Wire, Plain, for Concrete Reinforcement*; ASTM A 185, *Standard Specification for Steel Welded Wire Fabric, Plain, for Concrete*; and ASTM A 615, *Standard Specification for Deformed and Plain Billet-Steel Bars for Concrete Reinforcement* (Grades 40 and 60 only).

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 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks,* Appendix Q, provided that the composite section is prestressed so 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 and serving primarily as moisture barriers for internally insulated tanks shall be of metal classified for either primary component or secondary component service in API 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*, provided that the composite section is prestressed so 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 provisions of ACI 318, *Building Code Requirements for Reinforced Concrete*, and ACI 344R-W, *Design and Construction of Circular Wire and Strand Wrapped Prestressed Concrete Structures.*

4-3.4.2 Concrete LNG containers shall be inspected in accordance with ACI 311.4R, *Guide for Concrete Inspection*, and Section 4-5.

4-3.4.3 Metal components shall be constructed and tested in accordance with the applicable provisions in API 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*, Appendix Q.

4-3.4.4 Other materials used in the construction of concrete LNG containers shall be subjected to inspection and tests.

4-4 Marking of LNG Containers.

4-4.1 Each container shall be identified by the attachment of a nameplate in an accessible place marked with the following information:

(a) Builder's name and date built;

(b) Nominal liquid capacity (in barrels, gallons, or cubic meters);

(c) Design pressure for methane gas at top of container;

(d) Maximum permitted density of liquid to be stored;

(e) Maximum level to which container can be filled with stored liquid (*see 4-1.6.1*);

(f) Maximum level to which container can be filled with water for test, if applicable;

(g) Minimum temperature in degrees Fahrenheit or 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.

4-4.3 ASME storage containers shall be labeled in accordance with NFPA 704, *Standard for the Identification of the Fire Hazards of Materials*.

4-5 Testing of LNG Containers.

4-5.1 LNG containers shall be leak tested in accordance with the governing construction code or standard. All leaks shall be repaired.

4-5.1.1 Testing shall be performed in accordance with the inspection and test requirements of the applicable construction code. If no specific single construction code is applicable, the testing requirements of API 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*, shall be the basis for testing of containers designed for 15 psi (100 kPa) or less.

4-5.1.2 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 Chapter 6.

4-5.1.3 Containers and associated piping shall be leak tested prior to filling the container with LNG.

4-5.1.4 Containers shall be shipped under a minimum internal pressure of 10 psi (69 kPa) inert gas.

4-5.2 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 Procedures.

4-6.1 Prior to placing an LNG container into or out of service, the container shall be inerted by an approved inerting procedure.

4-6.2* Prior to taking a container out of service, the natural gas in the container shall be purged from the container in a safe manner by an acceptable inerting procedure.

4-7 Cool-down Procedure.

4-7.1 Cool-down of an LNG container shall be limited to a rate and distribution pattern that ensures that thermal stresses are within allowable limits during the cool-down period.

4-7.2 During initial cool-down of the tank, particular attention shall be given to tank penetrations to ensure proper performance of expansion bends or joints.

4-8 Pressure and Vacuum Control.

4-8.1 Provision shall be made to maintain the internal pressure and vacuum of LNG containers within the limits set by the design specifications by releasing or admitting gas as needed. Factors that shall be considered in sizing such pressure control means shall include the following:

(a) For pressure:

1. Loss of refrigeration;
2. Operational upset, such as failure of a control device;
3. Vapor displacement and flash vaporization during filling, as a result of filling, and as a consequence of controlled mixing of LNG of different compositions (which can result from weathering) or temperatures, or both;
4. Drop in barometric pressure;
5. Flash vaporization resulting from pump recirculation.

(b) For vacuum:

1. Withdrawal of liquid at the maximum rate;
2. Withdrawal of vapor at the maximum compressor suction rate;
3. Rise in barometric pressure;
4. Reduction in vapor pressure resulting from the introduction of subcooled LNG into the vapor space.

4-8.2 Provision for the admission and release of gas required in 4-8.1 shall be by any means compatible with the gas-handling facilities in the plant.

4-8.3 In addition to the pressure control means provided for in 4-8.1, LNG containers shall be equipped with direct-acting pressure relief valves and vacuum relief valves (vacuum breakers) communicating directly with the atmosphere and having capacities calculated for any likely combination of the factors in 4-8.1(a) and (b). The option of gas admission through the vacuum relief valves provided in API 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*, paragraph 6.2.3, shall not be permitted. Pressure relief valves also shall consider discharge that can accompany fire exposure. As a minimum, 4-8.3.1, 4-8.3.2, 4-8.3.3 and 4-8.3.4 shall apply.

Exception: ASME pressure vessels that can withstand the vacuum operating conditions in 4-8.1 shall not be required to be equipped with a vacuum breaker.

4-8.3.1 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 4-8 or CGA S-1.3, *Pressure Relief Device Standards — Part 3 — Compressed Gas Storage*.

4-8.3.2 When a container is exposed to an open fire, heat is transferred to the stored liquid. Additional heat is transferred simultaneously through the parts of the container not exposed to fire due to the high difference between the normal ambient temperature and the stored liquid temperature. The minimum total heat influx during a possible fire exposure of an insulated container shall be computed by the formula:

$$H = 1560\ C_1 A^{0.82} + H\eta$$

where:

H = Total heat influx (Btu per hour)

C_1 = Conductance of the insulation (Btu/ft^2 –hr –°F) [The value of C increases with temperature, and a mean value for the range from –260°F to +1660°F (–162°C to + 904.4°C) shall be used.]

A = Total exposed wetted surface area (ft^2)

Hη = Total normal heat gain to the stored liquid without fire exposures and at maximum ambient temperatures (Btu per hour).

4-8.3.3 If the insulation system, including any jacketing material, is such that it can disappear, deteriorate, or dislodge in an exposure fire, a higher heat gain occurs. This requires special consideration, depending upon the extent of loss of the insulating properties. If only a part of the insulation is lost, the heat gain shall be permitted to be calculated by the following formula:

$$H = (34,500 - 360\ C_2)\ A^{0.82} + H\eta$$

In this case, the value of C_2 is the mean value for the range of –260°F to + 100°F (–162°C to + 37.7°C).

4-8.3.4 The required relief valve capacity shall be computed by the following formula:

$$Q_a = (3.09)\frac{H}{L}\sqrt{\frac{T}{M}}$$

where:

Q_a = the required flow capacity of air [ft^3/hr at 60°F (16°C) and 14.7 psia (an absolute pressure of 101 kPa)]

H = the total heat influx (Btu/hr) from the formula in 4-8.3.3

L = the latent heat of vaporization of the stored liquid (Btu/lb)

T = the absolute temperature of the gas at the relief valve inlet (°F)

M = the molecular weight of the gas.

4-8.4 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 capacities determined in 4-8.3. Where only one relief device is required, a full-port opening three-way valve shall be permitted to be used under the relief device and its required spare in lieu of individual valves beneath each relief device.

4-8.4.1 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.

4-8.4.2 No more than one stop valve shall be closed at one time, thus maintaining the relief capacity of 4-8.3.

4-8.5 Safety relief valve discharge stacks or vents shall be designed and installed to prevent an accumulation of water, ice, snow, or other foreign matter and, if arranged to discharge directly into the atmosphere, shall discharge vertically upward.

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, sea water, or geothermal waters. 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. or less shall not be required to comply with this provision.

5-3.5 Each heated vaporizer shall be provided with a means to shut off the heat source from a location at least 50 ft (15 m) from the vaporizer. The device also shall be operable at its installed location.

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 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; or

(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 are 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 B31.3, *Chemical Plant and Petroleum Refinery Piping*. The additional provisions of this chapter shall apply to pressurized piping systems and components for flammable liquids and flammable gases. This chapter also shall apply to unpressurized or low pressure piping systems, including vent lines and drain lines, that handle 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 Seismic loads shall be considered in the piping design. Results of the seismic study of 4-1.3 or the accelerations in Table 4-1.3.8, as applicable, shall be used to determine the forces that apply to the piping design. The longitudinal stresses that are developed in this analysis shall meet the requirements of ASME B31.3, *Chemical Plant and Petroleum Refinery Piping*, 302.3.6(a). Container-associated piping up to and including the first container shutoff valve in LNG lines shall be designed to meet the provisions of 4-1.3.4(b).

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. Piping systems and components shall be designed to accommodate changes in pipe size or wall thickness 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 B31.3, *Chemical Plant and Petroleum Refinery Piping*, 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 B31.3, *Chemical Plant and Petroleum Refinery 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:

(a) 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; or

(b) Protected by insulation or other means to delay failure due to such extreme temperatures until corrective action can be taken by the operator; or

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

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 B31.3, *Chemical Plant and Petroleum Refinery 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 (–30°C).

Exception: Couplings meeting the requirements of ASME B31.3, Chemical Plant and Petroleum Refinery Piping, Section 315.

6-2.4* Valves.

6-2.4.1 In addition to complying with ASME B31.3, *Chemical Plant and Petroleum Refinery Piping*, Section 307, valves shall comply with ASME B31.5, *Refrigeration Piping*; ASME B31.8, *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. The tightness of all bolted connections shall be maintained to prevent leakage. Spring washers or other such 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. nominal diameter or less shall be threaded, welded, or flanged. Pipe joints larger than 2 in. nominal diameter shall be welded or flanged.

Exception: Joints of 4 in. nominal diameter or less shall be permitted to be threaded where necessary for special connections to equipment or components, provided that such special 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, 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 Gaskets shall be protected from exposure to fire and shall meet the temperature ranges to which they can be exposed.

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. 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. 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 ASME B31.3, *Chemical Plant and Petroleum Refinery Piping*, 328.2, 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 or 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 B31.3, *Chemical Plant and Petroleum Refinery 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.

NOTE: For information on identification of piping systems, see ASME A13.1, *Scheme for the Identification of Piping Systems.*

6-6 Inspection and Testing of Piping.

6-6.1 Pressure tests shall be conducted in accordance with ASME B31.3, *Chemical Plant and Petroleum Refinery 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 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: 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, provided it has been inspected visually in accordance with ASME B31.3, Chemical Plant and Petroleum Refinery Piping, 344.2.

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 B31.3, *Chemical Plant and Petroleum Refinery Piping*, 328.5.4) shall be examined fully by in-process examination in accordance with ASME B31.3, 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 Nondestructive examination methods, limitations on defects, the qualifications of the authorized inspector, and the personnel performing the examination shall meet the requirements of ASME B31.3, *Chemical Plant and Petroleum Refinery Piping*, Section 344.

Exception: Substitution of in-process examination for radiography or ultrasonics as permitted in ASME B31.3, Paragraph 341.4.1, shall be prohibited.

6-6.5 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.

6-6.6 Records and certifications pertaining to materials, components, and heat treatment as required by ASME B31.3, *Chemical Plant and Petroleum Refinery Piping*, subparagraphs 341.4.1(c) and 341.4.3(d), 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.

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

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 above the maximum pressure normally expected in the line but at less than the rated test 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 replaceable without taking the tank out of operation.

7-1.1.2 The container shall be provided with a high-liquid-level alarm. 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. A high-liquid-level flow cutoff device, if used, 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.

7-1.1.4 Containers with a capacity of 70,000 gal (265 m^3) or less, if attended during the filling operation, shall be permitted to be equipped with liquid trycocks in lieu of the high-liquid-level alarm, and manual flow cutoff shall be permitted.

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, as in cases where the refrigerant or intermediate fluids system is a part of the liquefaction system, a high-liquid-level alarm shall be provided in accordance with 7-1.1.2.

7-1.2.2 Paragraph 7-1.1.3 shall apply to installations specified in 7-1.2.1.

7-2 Pressure Gauge.

7-2.1 LNG Containers. Each container shall be equipped with a pressure gauge connected to the container at a point above the maximum intended liquid level.

7-2.2* Liquefaction Systems. See Appendix A.

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* Liquefaction Systems. See Appendix A.

7-4.3 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. To the extent possible, 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 can be 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®*.

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 shall be installed in accordance with NFPA 70, *National Electrical Code*, for hazardous locations.

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 cannot be energized until the container is purged of air; and

(b) Electrical equipment is deenergized prior to allowing air into the container; and

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

Table 7-6.2 Electrical Area Classification Table

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, below ground 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. *[SeeFigure 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.

Table 7-6.2 Electrical Area Classification Table (continued)

Part	Location	Group D, Division[1]	Extent of Classified Area[2]
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.
	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.

[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.

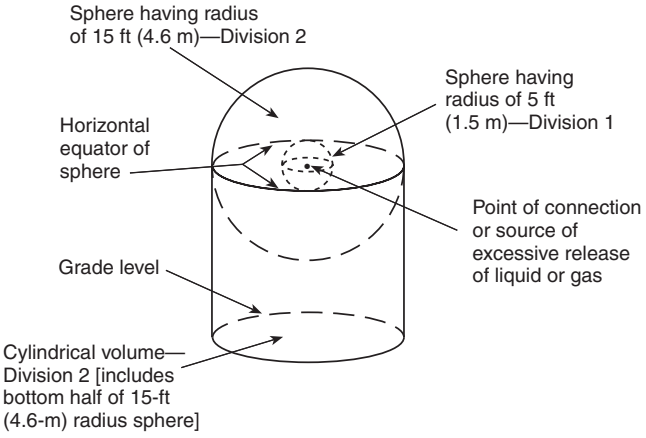


Figure 7-6.2(a) Extent of classified area.

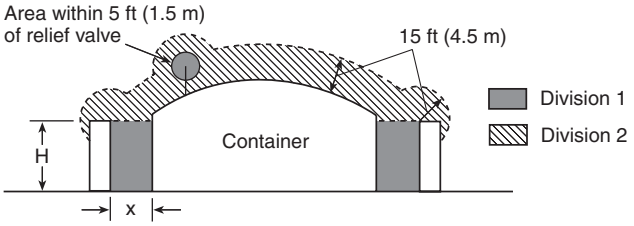


Figure 7-6.2(c) Dike height less than distance from container to dike (H greater than X).

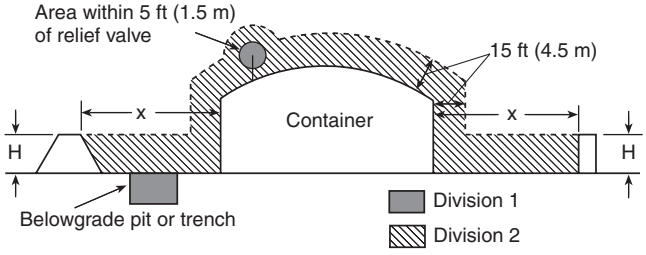


Figure 7-6.2(b) Dike height less than distance from container to dike (H less than X).

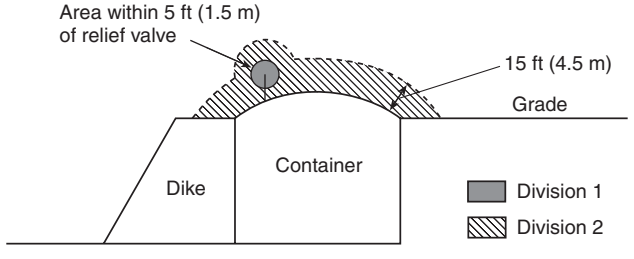


Figure 7-6.2(d) Container with liquid level below grade or top of dike.

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.

7-6.4 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.

7-6.5* A primary seal shall be provided between the flammable fluid system and the electrical conduit wiring system. If the failure of the primary seal would allow 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.

7-6.6 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 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.

7-6.7 Unless specifically designed and approved for the purpose, the seals specified in 7-6.3, 7-6.4, and 7-6.5 are not intended to replace the conduit seals required in NFPA 70, *National Electrical Code*, Section 501-5.

7-6.8 Where primary seals are installed, drains, vents, or other devices shall be provided for monitoring purposes to detect flammable fluids and leakage.

7-6.9 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.

NOTE: 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*.

7-7.2 Bonding. Static protection shall not be required where tank cars, tank vehicles, or marine equipment are loaded or unloaded by conductive or nonconductive hose, flexible metallic tubing, or pipe connections through or from tight (top or bottom) outlets where both halves of metallic couplings 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 in accordance with API RP 2003, *Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents*.

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.

NOTE: 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*.

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.

8-1.3 Where making bulk transfers into stationary storage containers, the LNG being transferred shall be:

(a) Compatible in composition or temperature and density with the LNG already in the container; or

(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.

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.

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

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, provided that bunkering is from a pipeline rather than from a barge.

8-4.3 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.

8-4.4 Pipelines shall be located on the dock or pier so that they are not exposed to damage from vehicular traffic or other possible cause 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.

8-4.5 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 or pumped out, and depressurized before disconnecting. Liquid isolation valves, regardless of size, and vapor valves 8 in. 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 minutes 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.

8-4.6 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. and larger shall be equipped with powered operators. Means for manual operation shall be provided.

8-4.7 Pipelines used for liquid unloading only shall be provided with a check valve located at the manifold adjacent to the manifold isolation valve.

8-4.8 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.

8-4.9 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.

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), 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:

(a) LNG Tank Vehicles — CGA-341, *Standard for Insulated Cargo Tank Specification for Cryogenic Liquids*;

(b) LP-Gas Tank Vehicles — NFPA 58, *Standard for the Storage and Handling of Liquefied Petroleum Gases*;

(c) 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.

8-7 Loading or Unloading Operations.

8-7.1 General.

8-7.1.1 At least one qualified person shall be in constant attendance while loading or unloading is in progress.

8-7.1.2 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.

8-7.1.3 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.

8-7.1.4 Loading and unloading areas shall be posted with signs that read "no smoking."

8-7.1.5 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.

8-7.1.6 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.

8-7.1.7 The transfer system shall be checked prior to use to ensure that valves are lined up properly. Transfer operations shall commence slowly, and 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.

8-7.1.8 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.

8-7.1.9 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.

8-7.1.10 No significant repair shall be done on the transfer system while transfer is taking place.

8-7.2 Tank Car or Tank Vehicle.

8-7.2.1 While tank car or tank vehicle loading or unloading operations are in progress, rail and vehicle traffic shall be prohibited within 25 ft (7.6 m) of LNG facilities or within 50 ft (15 m) of refrigerants whose vapors are heavier than air.

8-7.2.2 Prior to connecting a tank car, the car shall be chocked 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.

8-7.2.3 Unless required for transfer operations, truck vehicle engines shall be shut off. Brakes shall be set and wheels chocked 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.

8-7.2.4 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.

8-7.2.5 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.

8-7.2.6 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.

8-8 Hoses and Arms.

8-8.1 Hoses or arms used for transfer shall be 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.

8-8.2 Flexible metallic hose or pipe and swivel joints shall be used where operating temperatures are expected to be below –60°F (–51°C).

8-8.3 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.

8-8.4 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.

8-8.5 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.

8-9 Communications and Lighting.

8-9.1 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.

8-9.2* 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 upon sound fire protection engineering principles, analysis of local conditions, hazards within the facility, and exposure to or from other property. The evaluation shall determine, as a minimum:

(a) 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.

(b) The type, quantity, and location of equipment necessary for the detection and control of potential nonprocess and electrical fires.

(c) The methods necessary for protection of the equipment and structures from the effects of fire exposure.

(d) Fire protection water systems. (*See Section 9-5 and Appendix A.*)

(e) Fire extinguishing and other fire control equipment. (*See Section 9-6 and Appendix A.*)

(f) The equipment and processes to be incorporated within the emergency shutdown (ESD) system (*see Section 9-3*), including analysis of subsystems, if any, and the need for depressurizing specific vessels or equipment during a fire emergency.

(g) The type and location of sensors necessary to initiate automatic operation of the ESD system or its subsystems.

(h) The availability and duties of individual plant personnel and the availability of external response personnel during an emergency.

(i) The protective equipment and special training needed by individual plant personnel 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.

9-1.4 A detailed emergency procedure manual shall be prepared to cover the potential emergency conditions that can develop regardless of whether a fire has occurred. Such procedures shall include, but shall not necessarily be limited to, the following:

(a) Shutdown or isolation of various portions of the equipment and other applicable steps to ensure that the escape of gas or liquid is cut off promptly or reduced as much as possible;

(b) Use of fire protection facilities;

(c) Notification of public authorities;

(d) Standard first aid; and

(e) Personnel duties.

9-1.4.1 The emergency procedure manual shall be kept readily available in the operating control room, and it shall be updated as required by changes in equipment or procedures.

9-1.4.2 All personnel shall be trained in their respective duties as specified in the emergency manual. Those personnel responsible for the use of fire protection or other plant emergency equipment shall be trained in the use of that equipment. Refresher training shall be conducted at least annually.

NOTE: For information on fire brigades, see NFPA 600, *Standard on Industrial Fire Brigades.*

9-1.5 The planning of effective fire control measures shall be coordinated with the authority having jurisdiction and local emergency handling agencies, such as fire and police departments, who are expected to respond to such emergencies.

9-1.6 Normally, gas fires (including LNG fires) shall not be extinguished until the fuel source has been shut off.

9-2 Ignition Source Control.

9-2.1 Smoking and nonprocess ignition sources within the protective enclosure shall be prohibited.

Exception No. 1: Smoking shall be permitted only in designated and signposted areas.

Exception No. 2: Welding, cutting, and similar operations shall be conducted only at the times and in the places specifically authorized and in accordance with the provisions of NFPA 51B, Standard for Fire Prevention in Use of Cutting and Welding Processes.

9-2.2 Vehicles and other mobile equipment that constitute potential ignition sources shall be prohibited within impounding areas or within 50 ft (15 m) of containers or equipment containing LNG, flammable liquids, or flammable refrigerants.

Exception: Where specifically authorized and under constant supervision or where at loading or unloading facilities used specifically for the purpose.

9-3 Emergency Shutdown Systems.

9-3.1 Each LNG facility shall incorporate an emergency shutdown (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.

Exception: Where otherwise indicated in this standard (e.g., 5-3.3), equipment specified in other chapters shall not be permitted to be used to satisfy the requirements of an ESD system.

9-3.2 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.

9-3.3 Vessels containing liquids that are subject to metal overheating and catastrophic failure from fire exposure and not otherwise protected shall be depressurized by the ESD system.

9-3.4 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 either:

(a) Installed or located where they cannot be exposed to a fire; or

(b) Protected against failure due to a fire exposure of at least 10 minutes duration.

9-3.5 Operating instructions identifying the location and operation of emergency controls shall be posted conspicuously in the facility area.

9-3.6 Initiation of the ESD system(s) shall be either manual, automatic, or both manual and automatic, depending upon 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.

9-4 Fire and Leak Control.

9-4.1 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.

9-4.2 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.

9-4.3 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.

9-4.4 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 Public Fire Service Communication Systems*, as applicable.

9-5 Fire Protection Water Systems.

9-5.1 A water supply and a system for distributing and applying water shall be provided for protection of exposures; for cooling containers, equipment, and piping; and for controlling unignited leaks and spills.

Exception: Where an evaluation in accordance with 9-1.2 indicates the use of water is unnecessary or impractical.

9-5.2 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.

9-6 Fire Extinguishing and Other Fire Control Equipment.

9-6.1* 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*.

9-6.2 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 Pumper Fire Apparatus*.

9-6.3 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 20 lb (9 kg).

9-7 Maintenance of Fire Protection Equipment. Facility operators shall prepare and implement a maintenance program for all plant fire protection equipment.

9-8 Security.

9-8.1 The facility operator shall provide a security system with controlled access that shall be designed to minimize 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:

(a) LNG storage containers.

(b) Flammable refrigerant storage tanks.

(c) Flammable liquid storage tanks.

(d) Other hazardous materials storage areas.

(e) Outdoor process equipment areas.

(f) Buildings housing process or control equipment.

(g) 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 as necessary in the vicinity of protective enclosures and in other areas to promote the security of the facility.

9-9 Personnel Safety.

9-9.1* Personnel shall be trained biennially in the properties of LNG and the hazards and effects of exposure to LNG. Protective clothing and equipment shall be available.

9-9.2 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. Protective clothing shall comply with NFPA 1971, *Standard on Protective Clothing for Structural Fire Fighting*, and shall have an impermeable outer shell. Those employees requiring such protective clothing also shall be equipped with helmets, face shields, gloves, and boots suitable for the intended exposure.

9-9.3 Self-contained breathing apparatus shall be provided for those employees who can be required to enter an atmosphere that could be injurious to health during an emergency. Such apparatus shall comply with NFPA 1981, *Standard on Open-Circuit Self-Contained Breathing Apparatus for Fire Fighters*, and shall be maintained in accordance with the manufacturer's instructions.

9-9.4 Because natural gas, LNG, and hydrocarbon refrigerants within the process equipment usually are not odorized and the sense of smell cannot be relied upon to detect their presence, a portable flammable gas indicator shall be readily available.

9-10* Other Operations. See Appendix A.

9-10.1 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.

9-10.2* Manual emergency depressurizing means shall be provided where practical. Portions of the plant that can be isolated from storage tanks or other sources of supply can be depressurized by venting to the atmosphere through upward-pointing vent stacks.

9-10.3 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 Vehicle Fueling for Industrial and Commercial Facilities Using ASME Containers

10-1 Scope. This chapter provides requirements for the installation, design, fabrication, and siting of LNG containers of 70,000 gal (265 m^3) capacity and less and their associated equipment for use in applications such as vehicle refueling facilities and dedicated fuel supply for commercial and industrial applications that are designed and constructed in accordance with the ASME *Boiler and Pressure Vessel Code*.

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 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 the ASME *Boiler and Pressure Vessel Code*, Section VIII, or ASME B31.3, *Chemical Plant and Petroleum Refinery 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 either by:

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); or

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 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.

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:

(a) Horizontal force $V = Z_c \times W$

where:

Z_c = the seismic coefficient from Table 10-3.7.1

W = the total weight of the container and its contents.

(b) Design vertical force $P = {}^{2}/_{3} \times Z_c \times W$

(c) The seismic coefficient shall be permitted to be calculated in accordance with the nonbuilding structures provisions of the *Uniform Building Code*, using an Importance Factor I of 1.25. The minimum coefficient from Table 10-3.7.1 shall be used if the natural period of vibration, "T," is less than 0.3 seconds.

Table 10-3.7.1 Seismic Coefficient for Shop-Built Containers

Zone	Coefficient (Z_c)	Effective Peak Horizontal Acceleration (EPA) (%G)
1	0.09	7.5
2A	0.17	15.0
2B	0.23	20.0
3	0.34	30.0
4	0.46	40.0

NOTE 1 Source: *Uniform Building Code* seismic zone map.
NOTE 2 The EPA (%G) is equivalent to the seismic zones and can be used to determine Z_c in areas where seismic zones are not available.

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:

(a) Builders name and date built;

(b) Nominal liquid capacity;

(c) Design pressure at the top of the container;

(d) Maximum permitted liquid density;

(e) Maximum filling level;

(f) 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* The minimum separation distance between LNG containers or tanks containing flammable refrigerants and exposures shall be in accordance with Table 10-6.1.

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.

10-6.2 Buried and underground containers shall be provided with means to prevent the 32°F (0°C) isotherm from penetrating the soil. Heating systems shall be installed so that any heating element or temperature sensor used for control can be replaced.

Table 10-6.1 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)	(m3)	(ft)	(m)	(ft)	(m)
Less than 125	0.5	0	0	0	0
125 to 500	0.5 to 1.9	10	3	3	1
501 to 2000	1.9 to 7.6	15	4.6	5	1.5
2001 to 15,000	7.6 to 56.8	25	7.6	5	1.5
15,001 to 30,000	56.8 to 114	50	15	5	1.5
30,001 to 70,000	114 to 265	75	23		
Greater than 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]	