DEPARTMENT OF TRANSPORTATION

Office of Pipeline Safety Operations

[49 CFR Part 193]

[Notice No. 77-4; Docket No. OPSO-46]

LNG FACILITIES; FEDERAL SAFETY STANDARDS

Development of New Standards

AGENCY: Materials Transportation Bureau, Office of Pipeline Safety Operations, DOT.

ACTION: Advance Notice of Proposed Rulemaking.

SUMMARY: This advance notice invites public participation at an early stage in the rulemaking process for adoption of new Federal safety standards for liquefied natural gas (LNG) facilities.

The need for comprehensive new Federal LNG safety standards is evident from the concern expressed by Congressional committees; the Federal Power Commission and other Federal, state, and local agencies; nongovernment organizations; representatives of industry; and the public in general over the adequacy of present standards to provide for public safety. The new standards would govern the design (including site selection), construction, operation, and maintenance of LNG facilities used in the transportation of natural gas by pipeline in or affecting interstate or foreign commerce.

DATE: Comments must be received by September 1, 1977.

ADDRESS: Send comments to: Director, Office of Pipeline Safety Operations, Department of Transportation, Trans Point Building, 2100 Second Street, SW., Washington, D.C. 20590.

All comments received will be available for inspection and copying at Docket Room 6500, Trans Point Building.

FOR FURTHER INFORMATION CONTACT:

Peggy Hammond, 202-426-0135.

SUPPLEMENTARY INFORMATION: The need for comprehensive new Federal LNG safety standards is evident from the concern expressed by Congressional committees; the Federal Power Commission and other Federal, state, and local agencies; nongovernment organizations; representatives of industry; and the public in general over the adequacy of present standards to provide for public safety. Their concern arises because of the seriousness of potential hazards from LNG facilities coupled with the anticipated increase of LNG facility construction to meet the nation's energy needs, the developing wide variations in the design of facilities, the huge sizes of LNG storage tanks, and the projected location of new LNG facilities near population centers, or areas of greatest energy demand.

The existing Federal safety standards governing LNG facilities used in the transportation of natural gas by pipeline are contained in 49 CFR Part 192. These standards were adopted by Amendment 192-10, issued on October 10, 1972 (37 FR 21638). The Amendment added § 192.12, adopting as the Federal LNG safety standards the National Fire Protection Association (NFPA) Standard 59A (1971 edition), as well as the other applicable requirements of Part 192. Subsequently, the 1972 edition of NFPA 59A was adopted (41 FR 13590).

In the preamble to Amendment 192-10, it was stated that the NFPA Standard was adopted only as an interim measure while permanent regulations specifically applicable to LNG facilities were being developed. This notice is a step in that developmental process. Although this notice is not a proposal to amend the present standards, it contains a comprehensive set of draft regulations which are intended to serve as a basis for public comment and participation in identification of LNG safety problems and the development of appropriate regulatory solutions to those problems, considering all reasonable alternatives. Comments to this notice should assure that if a new Part 193 is adopted, it is founded on a broad source of information.

It is also important to point out that concurrent with this proceeding the Coast Guard is developing regulations under the Ports and Waterways Safety Act of 1972 (33 USC 1221 et seq.) for the storage and handling of hazardous materials, including LNG, at ports. MTB and the Coast Guard are coordinating their regulatory activities in this area to preclude problems involving overlapping jurisdiction.

As further discussed hereafter, the draft regulations are based in part on NFPA 59A, but more importantly, they address serious safety problems respecting an LNG facility that MTB believes are not adequately resolved by the present standards. Foremost among these problems are: (1) Protection of persons and property near a facility from thermal radiation caused by ignition of a major spill of LNG, (2) protection of persons and property near a facility from dispersion and delayed ignition of a natural gas cloud emanating from a major spill of LNG, and (3) mitigation of the potential for a catastrophic spill of LNG. The draft regulations suggest that these problems may be resolved by imposing more stringent exclusion zone requirements and other plant design requirements, particularly with respect to storage tanks, impounding systems, and environmental forces. At the same time, the draft regulations would permit flexibility in design to reduce the size of an exclusion zone, for example by installation of a planned ignition system or increasing the height of impounding dikes.

Interested persons should also note that the draft regulations relate to safety problems involving hazardous fluids other than LNG which may be used or stored at an LNG facility.

MTB expects that comments to this notice may serve as a basis for a future notice of proposed rulemaking. Therefore, considered comments are strongly urged regarding those draft regulations which relate to the safety problems mentioned above since those problems involve highly technical fields and unresolved behavioral phenomena which are still being researched. All commenters should address safety, environmental, and economic issues, support their comments with rationale and documentation, and where appropriate propose alternative regulations that would provide for an adequate level of safety.

The new Part 193 would be adopted under the Natural Gas Pipeline Safety Act of 1968 (49 USC 1671 et seq.). The jurisdiction of that Act is limited, however, to LNG facilities which are used in connection with a system for pipeline transportation of natural gas to consumers. Thus, both the existing standards, and the contemplated Part 193 would not apply to facilities used exclusively in the transportation of natural gas or LNG by modes other than pipeline. For example, the standards would not apply to an LNG storage and transfer facility at a marine terminal used to transfer LNG between ships or barges and rail or motor carriers unless the facility were also connected with a system for pipeline transportation. While MTB believes that almost all existing and planned facilities involve the supply or delivery of natural gas by pipeline, as LNG facilities become more widespread, it may be necessary to enlarge the scope of the Federal regulations to cover facilities which are not related to the pipeline transportation of natural gas. Any future action that MTB may take with regard to such nonpipeline related LNG facilities would be under the authority of the Hazardous Materials Transportation Act (49 USC 1801 et seq.). Interested persons are encouraged to advise MTB on the need to regulate any nonpipeline transportation related LNG facilities which may now exist or are planned.

In 1974, the Department's Office of Pipeline Safety contracted for a study by Arthur D. Little, Inc. (ADL) to provide safety information on LNG facilities. The study included a comparative analysis of national, state, local, industrial, and professional society codes, standards, practices, and regulations relating to LNG facilities. The ADL report, made in December 1974, is titled "Technology and Current Practices for Processing, Transferring, and Storing Liquefied Natural Gas." Copies of the report (NTIS No. PB-241048) are available from the National Technical Information Service, U.S. Department of Commerce, Springfield, Virginia 22151, telephone 703-557-4650, in paper for $7.75 and in microfiche for $3.

The ADL study provides useful information in developing safety regulations for LNG facilities. The study identified and analyzed many areas of public concern about the operation of LNG facilities. It also addressed many practices and functions where special precautions are needed to protect persons and property. Although now two years old, MTB believes that the results of the ADL study are still valid because they are consistent with current information obtained from other sources. Therefore, MTB has adopted the ADL report as a basis for this regulatory action.

The ADL report found that NFPA 59A was the basis for practically all codes—national, state, and local—for LNG facilities that exist today and that it "is generally accepted as establishing the minimum requirements for design and construction of LNG facilities." In Section 2.2, Overview of LNG Regulations, the ADL report stated, "It is logical, therefore, that NFPA 59A forms the basis for comparison of these codes, and the foundation on which to build any permanent regulation specifically applicable to LNG facilities." MTB agrees with this conclusion.

MTB therefore anticipates that NFPA 59A will be the foundation for a proposed Part 193, and has based most of the draft regulations set forth in this notice on the requirements of NFPA 59A. Not only are the requirements of the 1972 edition of NFPA 59A used as a basis, but also the requirements of the current 1975 edition. The draft regulations are based on the following principal provisions of the 1975 edition which are not in the 1972 edition:

Process equipment. Requires relief devices (§ 193.905(b)) and support protection (§ 193.815) for certain process components; provides sensing and alarm for combustible mixtures in buildings or process components (§§ 193.909 and 193.911).

Gasifiers. Establishes flow capacity for relief devices (§ 193.715); requires separate automatic valve for downstream temperature control (§ 193.709(b)).

Piping systems. Requires powered operation for certain valves that could be involved in an emergency (§§ 193.305(b), 193.605, 193.917(b), and 193.919); establishes limitations on design pressure for longitudinal weld pipe (§ 193.307(e)); requires nondestructive testing of welded pipe joints for LNG or flammable refrigerant systems (§ 193.1027); prohibits pressure tests of carbon or low alloy steel piping at temperatures below 35°F (§ 193.1025(b)); requires retention of records of materials (§ 193.219) and initial tests conducted (§ 193.1037(d)).

Transfer of LNG and refrigerants. Provides limit on prohibited oxygen content in purging vehicle tanks and provides check procedures for tank vehicles in exclusive LNG service (§ 193.1117(d)(4)).

Fire protection and safety. Establishes mandatory requirement for manual emergency depressuring of components (§ 193.1307(b)); requires portable flammable gas detector (§ 193.1307(g)) and self-contained air breathing apparatus (§ 193.1307(e)) be provided for LNG facility personnel.

Although this notice sets forth draft regulations based on the requirements of NFPA 59A, the regulations are not in the language of NFPA 59A. Rather, MTB has generally restated the requirements in terms of performance standards, using specific requirements where deemed necessary, and also referencing a few industry consensus standards. The use of performance language rather than specifications is consistent with the longstanding Departmental policy in prescribing Federal pipeline safety standards. Under this policy the standards prescribed what adequate level of safety must be achieved, leaving industry free to develop and use improved technological means of meeting the required level. Where necessary the performance standards may include tests and analytical procedures to check the level of performance.

In recent months representatives of the NFPA LNG Technical Committee have expressed the fear that the new Federal regulations would eliminate the need for the Committee and result in disbandment of a valuable group of LNG experts. Alternatively, the NFPA suggests that MTB work within the NFPA standards-setting procedure to bring about the needed changes in LNG safety regulations. MTB does not agree. In the safety area, MTB perceives the role of government as that of prescribing the level of safety industry is legally obligated to provide. The role of a nongovernment organization is to devise and recommend means of meeting the governmental prescribed safety level. Applying this principle to safety of LNG facilities, MTB prescribes what level of safety industry must achieve, stating the various requirements in objective language; NFPA, using current scientific knowledge and applying good engineering judgment, recommends means of meeting each of the requirements, stating its recommendations in specific terminology. Thus, the roles of MTB and NFPA are complementary. To that end, MTB invites NFPA to participate in the development of the new Part 193. Then, when the legal requirements have been published, NFPA can adapt 59A to those requirements. In that way, the Committee will continue as a needed and useful entity.

As recommended by the ADL report, MTB has carefully reviewed the following areas, which are covered by the draft regulations:

Acceptable thermal influx levels. One of the critical safety problems at an LNG facility is protection of the public from potential thermal radiation caused by a burning pool of LNG of other flammable fluid. Prolonged burning may occur in the event of a spill and subsequent ignition of the impounded liquid. Protection is now provided by a separation, or exclusion, distance measured from the edge of an impounding space. The exclusion distance required by NFPA 59A is based on an empirically derived formula: $d=8(A)^{0.5}$, where d=distance in feet and A=area of the impounding space.

The present exclusion distance standard results in a thermal flux at the boundary of the exclusion zone of roughly 10,000 to 13,000 BTU/ft²hr. At this level of intensity, direct exposure to humans produces unbearable pain in 0.4 seconds, or less. This level was established on the basis of conditions at existing LNG facilities, and may be inadequate as a safety standard for human exposure.

Under § 193.107, MTB suggests that the exclusion distance formula for human direct exposure be based instead on a thermal flux level of 1,000 BTU/ft²hr. At this level, exposure time on bare skin before unbearable pain is about 40 seconds. Humans would have more time to seek shelter or move farther away from a burning pool. Where structures provide some shielding from radiation, the formula would be based on higher tolerable flux levels, e.g., 2,000 BTU/ft²hr for wood homes, 6,700 BTU/ft²hr for infrequently occupied wooden or metal buildings, and 10,000 BTU/ft²hr for certain masonry buildings.

Section 193.107 would further modify the present exclusion distance requirement by taking into account (1) differences in elevation between an impounding space and any target which could be exposed to thermal radiation, and (2) a presumed wind velocity of 7 mph, which could tilt a flame approximately 45° in the direction of the target. The present requirement assumes equal elevations and zero wind velocity. MTB expects that after further research, additional modifications may be possible based on the shape of the impounding space and on full or partial shielding of open areas, as by a tall building. All modifications would be intended to provide for design flexibility and an adequate level of public safety.

Vapor dispersion hazards. Under § 193.109, MTB suggests that each LNG facility provide either an exclusion zone or controlled burning for protection from potential dispersion and subsequent ignition of a vapor or gas plume evolving from an impounded pool of LNG or other flammable liquid. This critical safety problem is now covered in the 1975 edition of NFPA 59A by a general performance standard related to plant design. However, this standard is subject to varying interpretation and application and may not adequately provide for public safety in light of the potential hazards involved. Thus, in addition to other design factors, MTB believes that either an exclusion distance determined in accordance with uniform methodology or controlled burning is needed to provide a realistically adequate safeguard.

The suggested exclusion distance would be determined in accordance with prescribed parameters and spill conditions, using applicable parts of the mathematical dispersion model set forth in the "American Gas Association Project IS-3-1, LNG Safety Program, Interim Report on Phase II Work." This model is suggested on the basis that it provides the best correlation with experimental data. The distance would be measured from an impounding space to a point where most pockets of the highest concentration of gas in air are diffused to a noncombustible level. In computing the distance under § 193.109, an operator would take into account important design factors such as the nature of the impounding system, seismic activity, air traffic, and insulation of proper integrity. Engineering design with respect to these and other factors can minimize the chance of a catastrophic failure or the rate of vapor evolution after a spill. Thus, for example, in an area where seismic intensities are predictably low, in light of the other suggested design requirements of the new Part, a catastrophic failure is unlikely. In this situation, the exclusion distance would be computed on the basis of a piping failure alone, resulting in a shorter distance than if the basis were a catastrophic failure.

On the other hand, where seismic activity is high, even with more stringent design requirements, a catastrophic failure may occur, and the exclusion distance would be based on a catastrophic spill of all the liquid to be impounded. If a long exclusion distance cannot be provided, the distance might be moderated by other design factors, or an operator might choose the alternative of controlled burning under § 193.109(f). In the latter case, protection would be provided by the suggested thermal radiation exclusion zone and by voluntary methods such as the use of fire suppression techniques to control the rate of burning.

Standards variation for different population densities. For new LNG facilities, the draft regulations are intended to assure a uniformly acceptable risk to persons and property surrounding a facility, regardless of population density. Because of the nature of the potential hazards involved, this same assurance cannot be made for existing facilities without imposing more stringent exclusion distance and other design requirements. Such action, however, would be prohibited by Section 3 of the Natural Gas Pipeline Safety Act of 1968. Even so, MTB believes that the public will be more at risk from new facilities than existing ones; and State or local zoning controls can be used to minimize risks where necessary.

MTB has not drafted the regulations to provide varying levels of safety for different population densities for the following reasons: First, while the overall risk presented by a facility would vary in proportion to population because of the potential losses involved, MTB believes that the seriousness of potential hazards such as thermal radiation and vapor dispersion necessitates minimizing the exposure of individuals to those hazards. This would be accomplished under the draft regulation by limitations on activities inside an exclusion zone (§§ 193.107 and 193.109) and other uniformly applicable design requirements.

Secondly, any reduction in safety for areas of low population might be accompanied by an unacceptable increased risk to facility personnel.

Thirdly, additional special design features necessary to maintain an acceptable level of safety in an area of growing population density might be economically impracticable long after initial siting and construction.

Fourthly, the likelihood of failure at an LNG facility does not vary in proportion to population density.

Finally, MTB does not have enough information to serve as a basis for suggesting varying levels of LNG facility safety even if they were deemed appropriate.

Diking for transfer lines. The draft Subpart E on impoundment design and capacity would require an impounding system for transfer piping and cargo transfer systems to contain any spill from transfer lines.

Criteria for onsite separations distances for potentially hazardous areas. Section 193.113 would require a combination of clearances between critical components and between components and the site boundary to minimize hazards due to spills and collapse of equipment and to provide for mobility in an emergency. Where losses of plant equipment would not present or contribute to a hazard, onsite separation distances would not be required. MTB is continuing to develop more specific criteria for safe separation distances and welcomes any comments in this regard.

Design criteria for earthquake, wind, and snow loads for LNG storage tanks. Section 193.111 would require each operator to conduct a seismic investigation for certain high risk LNG facilities in accordance with criteria which are consistent with requirements applicable to nuclear power plants under 10 CFR Part 100. Certain critical components used in these facilities would have to be designed based on the information acquired, or if the components are used in other facilities, the seismic values set forth in the Uniform Building Code (UBC), considering both vertical and horizontal seismic motion. LNG facilities would be prohibited in certain active seismic areas. Also, where the estimated maximum seismic acceleration at a site has a 0.5 percent probability of exceeding 30 percent G in 50 years or exceeds 30 percent G based on a recorded earthquake, foundations of LNG storage tanks would have to be placed on bedrock and special control systems provided.

The suggested requirements under §193.117 for wind loading on a storage tank are based on the probability of a tornado occurring in 50 years. An operator would have to consider snow and ice loading in the design of a storage tank under §193.505.

Selection of spill design accident, without regard to type of shutdown system. The ADL study suggests that to require impoundment capacities for process, transfer, and equipment areas large enough to hold a timed spill is unnecessary where shutdown systems to stop the flow of liquid will react in a shorter time. Therefore, the draft §193.441 would permit a smaller capacity when twice the shutdown time by such a system is less than the presently required timed spill.

Periodic inspections and ongoing training. The ADL study points out that the NFPA 59A standard is lacking in requirements for periodic inspection, ongoing training programs, accident reporting, operating reports, and similar activities related to the long-term safe operation and maintenance of LNG facilities. Therefore, MTB suggests new requirements for periodic tests and maintenance procedures in Subpart M; for operating procedures (§ 193.1105), monitoring (§ 193.1107), personnel training (§ 193.1115), recordkeeping (§ 193.1141), and investigation of failures (§ 193.1121), in Subpart L; and fire fighting provention (§ 193.1305), plans (§ 193.1307), and training (§ 193.1311) in Subpart N. Accident reporting for LNG facilities used in the transportation of natural gas by pipeline is presently required by 49 CFR Part 191.

In addition to the NFPA 59A requirements and the ADL report suggestions mentioned above, the draft regulations contain some significant new requirements:

Control systems. The draft regulation would expand previous coverage or establish new requirements in the areas of: performance capability during conditions of a controllable emergency (§ 193.903(b)), extreme environmental conditions (§ 193.303(a)), relief device capability to control overpressure during normal or emergency conditions (§ 193.905(b)); sensing devices to monitor and alarm systems to alert personnel to process malfunctions or detect presence of combustible gas that could lead to hazardous situations (§§ 193.421(d), 193.423, 193.527, 193.909, and 193.911); location and operation of safety control valves (§ 193.917), automatic shutdown systems (§§ 193.605, 193.805, and 193.919), auxiliary controls (§ 193.923), and control center instrumentation (§ 193.921).

Construction. The draft regulations would establish new requirements for: development of construction procedures (§ 193.1005); construction inspection (§ 193.1011); qualification of construction workers and inspectors (§§ 193.1009 and 193.1013); and cleanup after construction (§ 193.1015).

Tests and inspections. In addition to strength and leak tests requirements, Subpart K would establish new requirements for control systems tests and inspections (§ 193.1031), storage tank tests (§ 193.1033), and keeping records of these initial inspection and testing activities (§ 193.1037).

Operations. The draft regulation would establish new requirements for determining maximum and minium allowable operating pressures (§ 193.1137), written procedures for transfer operations (§ 193.1117), and responding to foreseeable emergencies (§ 193.1109).

Site security, storage tank design, impoundment design and capacity, and corrosion control. The draft regulations would establish significantly new requirements in areas of site security (§§ 193.1123–193.1135); storage tank design (Subpart F), particularly with respect to penetrations (§ 193.511), instrumentation (§ 193.527), and stratification (§ 193.507); impoundment design and capacity (Subpart E), particularly with respect to components requiring impoundment (§ 193.403); dike height (§193.419), and containment of a sudden total release of liquid from a component (§ 193.415); and corrosion control (Subpart O).

MTB invites all interested persons to participate in the development of new LNG safety standards by submitting in writing by September 1, 1977, such information and comments as they may desire. The September 1 deadline should balance the desires of interested persons for sufficient time to study and evaluate the draft regulations with the need for priority action in this rulemaking proceeding. Comments received after that date will be considered so far as practicable. Communications should identify the docket and notice numbers and be submitted in triplicate to the above address. All comments received will be available for inspection and copying in Docket Room 6500.

Again, MTB emphasizes that this notice is not a proposal to amend the present regulations. After analyzing the response to this notice, MTB may issue another notice (or notices), proposing specific amendments to Title 49 CFR. Interested persons will then have an opportunity to comment on the specific rulemaking proposals. Any requests for additional time to comment on this notice will be considered in light of the length of the initial period for public comment and the fact that an additional comment period is to be provided in conjunction with any future notice of proposed rulemaking.

IMPACT EVALUATION

To ensure that the new Part 193 does not result in costs to the private sector, consumers, or government above those necessary to provide an adequate level of public safety, MTB encourages the submission by interested persons of information on the annual and aggregate costs, benefits, and other anticipated impacts associated with each of the draft regulations and all alternatives which commenters may suggest thereto. This information would enable MTB to adequately consider the impact of any future rulemaking proposals early in the developmental process. Persons wishing to submit such information are asked to take the following considerations into account:

Benefits. The primary benefits of the draft regulations are presumptive reductions in the level of public risk associated with the design, including site selection, construction, operation, and maintenance of new LNG facilities and the operation and maintenance of existing facilities. Public risk is considered as the combination of the probability that an accident will occur, and the magnitude of the expected loss resulting from that accident (in terms of deaths/injuries, property loss and damage, economic disruptions in the supply of natural gas to a community, etc.). Primary benefits, therefore, take the form of either reductions in the probability that accidents will occur or reductions in the magnitude of the expected losses, or both; and these reductions are based on the level of risk that would prevail with and without promulgation of the draft regulations. The net difference between the two is an important element in determining what constitutes an adequate level of public safety.

The following secondary benefits should also be considered in estimating overall benefits of new regulations: Reduction in the cost of litigation, fewer delays due to governmental proceedings, economic gains from the timely development of LNG facilities, and fewer abandonments of planned facilities due to public opposition on safety grounds.

MTB recognizes that estimating safety benefits in these terms—especially for performance standards—can be a difficult and time-consuming task. It also realizes that work has already been done in evaluating the risks associated with LNG facilities (e.g., Final Environmental Impact Statement for the Construction and Operation of an LNG Terminal at Oxnard, California, FPC, December 1976). MTB believes, however, that improved effort in this direction is desirable to determine whether any proposed LNG safety standards are reasonable and economically practicable. The bases for this view are that no generally accepted risk assessment procedure presently exists, probability estimates have not been developed for accidental events at a facility, and convincing arguments have not been presented to show that the probability of major accidents is negligible.

In regard to the use of probability concepts, the availability and quality of data will affect the degree of uncertainty surrounding the level of public risk associated with LNG facilities. Also, the probability data, when combined with estimates of the magnitude of the expected losses resulting from an accident, is useful for determining whether there would be unnecessary regulation of a facility.

Costs. The costs associated with the draft regulations (and any alternatives suggested to the regulations) must be assessed since costs are an important element in determining what constitutes an adequate level of public safety. Although MTB believes that the costs of complying with the draft regulations would not be unwarranted, either in absolute dollar amounts or on the basis of average annual costs (calculated at a 10 percent capital recovery factor over a 20-year period), compliance could impose certain cash outlays about which MTB has little information.

There are at least three other considerations MTB would ask those desiring to submit economic data to bear in mind. First, as in the measurement of the benefits of the draft regulations, their costs should be measured on the basis of the impact "with" and "without" the regulations. In this regard, it is doubtful whether the costs of compliance with Federal regulations no more stringent than the 1975 edition of NFPA 59A or any other generally followed standard of performance should legitimately be regarded as costs of government regulation. The costs of regulations of this type basically are the same as those costs self-imposed by the regulated industry "without" the regulations, unless there is evidence to suggest that a significant segment of the industry does not conform to self-imposed industrial standards. Accordingly, the costs "without" the regulations should be based on actual safety practices currently followed with respect to design, construction, operation, and maintenance of an LNG facility.

The timing of the economic impact of the draft regulations is the second important consideration to bear in mind. Any new standards to be proposed by MTB would have an impact on the some 121 LNG facilities now in existence in the United States, as well as those that may be built over the next 20 years. Accordingly, MTB requests data on cost impacts on future LNG facilities to be built over the next 20 years, and future changes to current facilities that might take place over a 20-year period.

The third consideration concerns future price level changes which would affect the magnitude of the dollar outlays stemming from the regulations. For purposes of comment, these price level changes should generally be ignored; and all costs should be stated in terms of constant (i.e., 1977) dollars.

Persons wishing to provide MTB with data on these and other matters relating to the potential costs of the draft regulations may find the cost categories appearing hereafter helpful as a basis for organizing and developing the data to be submitted. However, these cost categories are designed to serve only as a very general guide or checklist; they are not intended to be comprehensive or limiting.

EXAMPLE OF TYPES OF ECONOMIC INFORMATION REQUESTED

(a) Standards requiring the installation and purchase of new equipment, or instruments, and material.

1. Type of equipment or material.
2. Estimated amount (number) of equipment or material required.
3. Current unit cost of equipment or material (purchase price).
4. The availability of the equipment or material (supply), and the expected delivery time for the equipment or material.
5. Expected time and cost to install equipment.
6. If installation of the new equipment will cause other equipment to be put out of productive service for some period of time, the costs associated with this action.
7. If installation of the new equipment will increase or decrease the productivity of other equipment, the associated costs.

(b) Standards impacting on personnel training requirements.

1. Impact by job category;
2. By number of personnel;
3. By length of training; and
4. By job category cost of training.

(c) Standards requiring the collection or processing of information.

1. By type of information;
2. By number of forms; and
3. Total costs of collecting/processing information.

(d) Standards requiring certain procedural actions be taken (but not requiring additional equipment or personnel).

1. Estimated facilities affected;
2. Estimated time to complete procedure versus the current operating practice;
3. Estimated frequency; and
4. Estimated cost per facility.

(e) Standards requiring additional personnel.

1. By job category;
2. By number required; and
3. By job category wage rate (current).

(f) Standards requiring additions to or modification of already existing (in place, or in productive service) equipment.

1. Type of equipment;
2. Type of adjustments or modifications to this equipment;
3. Amount of equipment affected;
4. Unit cost of making adjustments or modifications;
5. If adjustments/modifications will cause other equipment to be put out of productive service for any period of time, the costs associated with this action; and
6. If adjustments/modifications will cause an increase or decrease in the productivity of other equipment.

(g) Standards requiring additions to or modifications of present requirements related to siting (e.g., exclusion zones, etc.) and structural design (e.g., impoundment).

1. Type of requirement affected;
2. Amount of land;
3. Value of land; and
4. Added unit costs of complying with regulations.

Acknowledgements: In preparing the draft regulations, valuable technical information, advice, and assistance have been provided in some areas by W. C. Jennings, former head of the Department's pipeline safety program. Additionally, MTB personnel have conferred with operators, nationally established constructors of LNG facilities, other technical branches of government, and have researched and studied many technical reports, codes, and data. The principal MTB authors of this advance notice are Lucian M. Furrow, Chief, Regulations Division; Walter Dennis, Staff Engineer; and Robert L. Beauregard, Attorney, Office of the General Counsel.

Accordingly, the draft Part 193 is set forth below.

Issued in Washington, D.C. on April 14, 1977.

CESAR DELEON,
Acting Director, Office of Pipeline Safety Operations.

PART 193—LIQUEFIED NATURAL GAS FACILITIES: FEDERAL SAFETY STANDARDS

Subpart A—General

Subpart B—Site Related Design Requirements

Subpart C—Materials

Subpart D—Design of Components

Subpart E—Impoundment Design and Capacity

Subpart F—Storage Tanks

Subpart G—Design of Transfer Systems

Subpart H—Gasification Equipment

Subpart I—Liquefaction Equipment

Subpart J—Control Systems

Subpart K—Construction

Subpart L—Operations

AUTHORITY: Sec. 3, Pub. L. 90-481, 82 Stat. 721 (49 U.S.C. 1672); 40 FR 43901, 49 CFR 1.53(a) and paragraph (b)(2) of Appendix A to Part 102 of this Title.

Subpart A—General

§ 193.1 Scope of part.

This part prescribes safety standards for LNG facilities used in the transportation of natural gas by pipeline in or affecting interstate or foreign commerce.

§ 193.3 Applicability.

(a) The requirements of this part governing a new LNG facility apply to facilities initially placed in operation after (day before effective date) except that requirements for design, installation, and construction in Subparts B-K of this part apply to facilities substantially under development before (effective date) only to the extent that compliance is practical.

(b) The requirements of this part governing an existing LNG facility apply to facilities initially placed in operation before (effective date).

§ 193.5 Definitions.

As used in this part—

"Ambient gasifier" means a gasifier which derives heat from naturally occurring heat sources, such as the atmosphere, sea water, surface waters, or geothermal waters.

"Barrel" means a volumetric unit which is 42 U.S. gallons, 5.6146 feet^3 or 0.1590 meters,^{3} each quantity being considered as equal to the other.

"Bunkering" means loading the bunkers or tanks of a marine vessel with a fuel intended for operation of the vessel.

"Cargo transfer system" means a component or system of components and associated area for transferring hazardous liquids in bulk between the closest inline valve on transfer piping and a tank car, tank truck, marine vessel, or pipeline, including connections, arms, hoses, and the area in which a tank car, tank truck, or pipeline is located during transfer, but not the area in which a marine vessel is located.

"Component" means any part or system of parts functioning as a unit in an LNG facility.

"Container" means a component other than piping which confines a hazardous fluid.

"Control system" means a component or system of components functioning as a unit, including control valves, and sensing, warning, relief, shutdown and failsafe devices, which is activated either manually or automatically to establish or maintain the performance of another component.

"Controllable emergency" means an emergency where reasonable and prudent action can prevent a hazard to persons or property from occurring.

"Critical component" means a component which may cause, fail to prevent, or increase a hazardous condition if operational capability is impaired or malfunction occurs.

"Determine" means make a thorough investigation using scientific methods, reach a decision based on sound engineering judgment, and record the decision and its basis with appropriate documentation.

"Dike" means a structural arrangement, which may be of natural geological formation, compacted earth, concrete, or other material, sealed to form a barrier for preventing liquid from flowing in an unintended direction.

"Emergency" means a deviation from normal operation, a structural failure, or severe environmental conditions that probably would cause a hazard to persons or property.

"Exclusion zone" means an area surrounding an LNG facility in which the operator has the authority by ownership or other legal arrangement to control all activities in accordance with §§193.107 and 193.109 for as long as the facility is in operation, including the exclusion or removal of persons and property.

"Failsafe" means a design feature which will maintain or result in a safe condition in the event of malfunction or failure of a power supply, component, or component part.

"G" or "g" means the standard acceleration of terrestrial gravity of 32.17 feet per second per second (980.66 centimeters per second per second) unless otherwise stated by this part.

"Gas," except when designated as inert, means natural gas, flammable gas, or gas which is toxic or corrosive.

"Gasification" means an addition of thermal energy changing a liquid medium to a gaseous state at a point where its critical temperature is exceeded, such that a liquid state cannot be achieved by compression.

"Gasifier" means a heat transfer facility designed to introduce thermal energy in a controlled manner for changing a liquid medium to a gaseous state.

"Heated gasifier" means a gasifier which derives heat from other than naturally occurring heat sources.

"Impounding space" means a volume of space formed by dikes and floors which is designed to hold a spill of LNG or other hazardous liquid.

"Impounding system" includes an impounding space and dikes and floors, including those for conducting the flow of spilled hazardous liquids to an impounding space.

"Liquefied natural gas" or "LNG" means natural gas which has been changed to a liquid cryogen by the reduction in temperature.

"LNG facility" means a facility for liquefying natural gas or transferring, storing, or gasifying liquefied natural gas, including rights-of-way, buildings, equipment, piping, and associated facilities, but not including tank cars, tank trucks, marine vessels, fuel systems for motor vehicles, or portable dewar vessels.

"Natural gas" means natural or synthetic gas having methane (CH_4) as its major constituent.

"Normal operation" means functioning within design ranges of pressure, temperature, flow, or other operating criteria without malfunction or personnel error which results in the activation of any safety control.

"Operation" means activation of any component or introduction of any fluid into any component for purposes other than testing.

"Operator" means a person who owns or operates an LNG facility.

"Person" means any individual, firm, joint venture, patnership, corporation, association, state, municipality, cooperative association, or joint stock association and includes any trustee, receiver, assignee, or personal representative thereof.

"Piping" or "Piping system" means all pipe, tubing hoses, fittings, valves, pumps, connections, insulation, safety devices or related components for containing the flow of a fluid.

"Secretary" means the Secretary of Transportation or any person to whom he has delegated authority in the matter concerned.

"Storage tank" means a container for storing a hazardous fluid.

"Transfer piping" means all permanent and temporary piping, supports, and associated area used for transferring hazardous liquids between containers, between a container and a cargo transfer system, or between a sump basin and a receiving vessel.

"Transfer system" includes transfer piping and cargo transfer system.

"Vaporization" means an addition of thermal energy changing a liquid medium to a vapor which is capable of being converted back to a liquid state by compression.

"Vaporizer" means a heat transfer facility designed to introduce thermal energy in a controlled manner for changing a liquid medium to a vapor state.

§ 193.7 **Rules of regulatory construction.**

(a) As used in this part—

(1) "Includes" means including but not limited to;

(2) "May" means is permitted to or is authorized to;

(3) "May not" means is not permitted to or is not authorized to; and

(4) "Shall" or "must" is used in the mandatory and imperative sense.

(b) In this part—

(1) Words importing the singular include the plural;

(2) Words importing the plural include the singular; and

(3) Words importing the masculine gender include the feminine.

§ 193.9 **Filing, inspection and maintenance plans.**

(a) Except as provided in paragraph (b) of this section, each operator shall file with the Secretary before (6 months after effective date) or 6 months after an LNG facility is initially placed in operation, whichever is later, a plan for inspection and maintenance of each LNG facility. In addition, each change to an inspection and maintenance plan must be filed with the Secretary within 20 days after the change is made.

(b) Paragraph (a) of this section does not apply to a facility—

(1) Subject to the jurisdiction of a State agency that has submitted a current certification or agreement with respect to the facility under Section 5 of the Natural Gas Pipeline Safety Act of 1968 (49 U.S.C. 1674); and

(2) For which an inspection and maintenance plan and changes thereto are required to be filed with that State agency.

(c) Plans and changes filed with the Secretary must be sent to the Director, Office of Pipeline Safety Operations, Department of Transportation, Washington, D.C. 20590.

§ 193.11 **Incorporation by reference.**

(a) Any documents or parts thereof incorporated by reference in this part are a part of this regulation as though set out in full.

(b) All incorporated documents are available for inspection in Docket Room 6500, Trans Point Building. In addition, the documents are available at the addresses provided in Appendix A to this part.

(c) The titles and applicable editions for the publications incorporated by reference in this part are provided in Appendix A to this part.

Subpart B—Site Related Design Requirements

§ 193.101 **Scope.**

This subpart prescribes site related requirements for the design of a new LNG facility or an existing facility which is replaced, relocated, or otherwise changed.

§ 193.103 **Acceptable site.**

A site may not be used for an LNG facility unless it is investigated and designed in accordance with the requirements of this subpart.

§ 193.105 **General.**

An LNG facility must be located at a site of suitable size, topography, and configuration to minimize the hazards to persons and property resulting from leaks and spills of LNG and other hazardous liquids at the site. In selecting a site, each operator shall determine all site related characteristics which could jeopardize the integrity and security of the facility. A site must provide ease of access so that personnel, equipment, and materials from offsite locations can reach the site for fire fighting or controlling spill associated hazards.

§ 193.107 **Thermal radiation protection.**

(a) *Thermal exclusion zone.* Each LNG facility must have a thermal exclusion zone. Within the exclusion zone an impounding system for flammable liquid may not be located closer to targets listed in paragraph (c) of this section than determined by the prescribed exclusion distances.

(b) *Measurement.* The exclusion distance "d" is measured as shown in the following diagram along the line (PT) in a vertical plane defined by the points (T) and (D), where

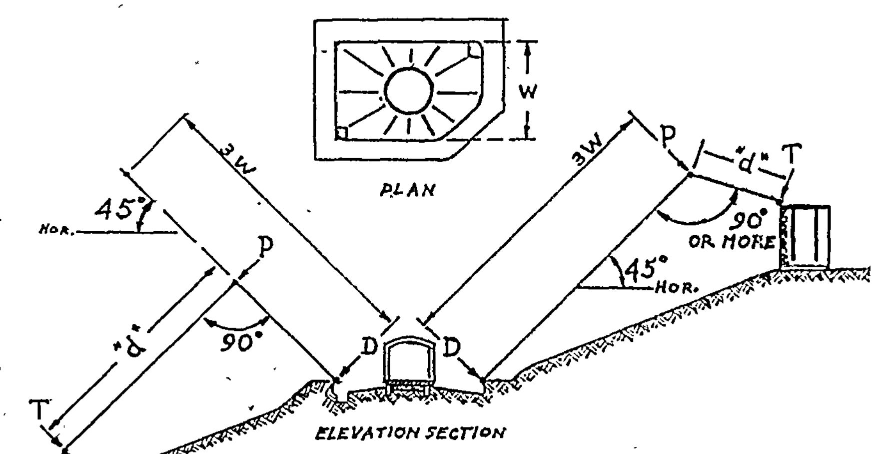
(T) is a point at the top of the target;

(D) is a point closest to (T) on the top inside edge of the dike;

(PD) is a line in the vertical plane which intersects (D) at an angle of 45° above horizontal;

(w) is the inside distance across the top of the impounding space measured normal to (PD); and

(P) is located where (PT) and (PD) intersect at an angle of 90° or where (PD) equals 3(w), whichever results in the shortest length of (PD).



IMPOUNDMENT & TOPOGRAPHY

(c) *Exclusion distance length.* The length of an exclusion distance in feet may not be less than the distance "d" determined in accordance with the following formula for the target concerned, where "A" equals inside area in square feet measured across the top of the impounding space:

Target	Exclusion distance
(1) Places of outdoor assembly including beaches, parks, playgrounds, and pedestrian paths.	$d=3.6(A)^{0.5}$
(2) Structures made of cellulose or metal which— (i) Are frequently occupied by humans; (ii) Contain flammable or toxic materials; (iii) Have exceptional value or contain objects of exceptional value; or (iv) Could result in additional hazard if damaged by thermal radiation.	$d=2(A)^{0.5}$
(3) Structures made of brick, stone, or other masonry materials, which are fire resistant and have not more than 10 percent window area.	$d=.8(A)^{0.5}$
(4) Other structures made of cellulose metal or masonry materials; trees; and vegetation.	$d=1.1(A)^{0.5}$

§ 193.109 **Combustible vapor-gas dispersion protection.**

(a) *Dispersion exclusion zone.* Except as provided by paragraph (f) of this section, each LNG facility must have a dispersion exclusion zone with a boundary described by the minimum exclusion distance computed in accordance with this section. The following are prohibited in a dispersion exclusion zone:

(1) Places of outdoor assembly; and

(2) Structures which are frequently occupied by humans, contain flammable or toxic materials, are sufficiently strong to be a container for blast wave initiation, have exceptional value or contain objects of exceptional value, or which could result in additional hazard if damaged by concussion or fire.

(b) *Exclusion distance.* A minimum exclusion distance must be computed for each impounding system which serves components containing LNG or flammable liquids with a boiling temperature of 98.6° F (37° C) or less. For liquids other than LNG, the minimum distance is computed by assuming the liquid to be LNG, except that under paragraph (d) (4) (i) of this section, the boiling rate may be determined by use of the liquid. The minimum exclusion distance in feet equals the sum of the estimated dispersion distance (D_c) plus the estimated deflagration protective distance (D_d). It is measured radially from the inside edge of an impounding system along the ground contour to the exclusion zone boundary.

(c) *Dispersion distance* (D_c). (D_c) must be estimated in accordance with applicable parts of the mathematical model beginning a page D-90, in Section D of "American Gas Association Project IS-3-1, LNG Safety Program, Interim Report on Phase II Work," subject to the following parameters and other requirements of this section:

(1) Average gas concentration in air=2.0 percent.

(2) Gifford-Pasquill atmosphere category=F (moderately stable).

(3) Wind velocity=5.0 MPH.

(4) Lateral dispersion adjustment factor, (GAMY)=0.00.

(5) Vertical dispersion adjustment factor (GAMZ)=0.00.

(6) Vertical displacement factor (ALM)=1.00.

(7) Temperature of external impounding surfaces at northern latitudes: above 45°=37° C; 35° to 45°=47° C; below 35°=57° C.

(d) *Vapor.* In computing dispersion distance (D_c) under paragraph (c) of this section, the following applies:

(1) For sites not subject to paragraph (d) (2) of this section, the value of (D_c) must not be less than a value resulting from one of the following vapor generation conditions:

(i) Vapor generation rate equals the maximum constant rate of discharge from failed transfer piping having the greatest overall flow capacity.

(ii) Vapor generation from sudden contact of LNG with 100 percent of the impounding system floor area and 50 percent of all liquid impounding surfaces which the liquid could contact, including the walls and roof of the component served, plus flash vaporization from the maximum constant rate of discharge from failed transfer piping having the greatest overall flow capacity.

(2) For sites located in active seismic areas having a potential for ground rupture or seismic accelerations in excess of 0.3G as determined under § 193.111, or where other surrounding conditions exist such that structural integrity of the component served cannot be assured with a high degree of certainty (e.g., high density commercial or military air traffic, and military test sites for aircraft and missiles), the value of (D_c) is based on the following applicable conditions:

(i) For Classes 2 and 3 impounding systems, a sudden total spill of the maximum contents of the largest component served, with vapor generation resulting from liquid contact with all exposed surfaces of the impounding system and outer component surfaces and flash vaporization from the contents of the component served.

(ii) For Class 1 impounding systems, a volume discharged from transfer piping equal to the impounding capacity required by this part for transfer piping, with vapor generation resulting from liquid contact with all exposed surfaces of the impounding system, heat transfer to the liquid from any collapsed component roof, and flash vaporization from the maximum contents of the component served or from the liquid discharged by transfer piping, whichever is greater.

(3) As applicable for Classes 2 and 3 impounding systems, the assumed maximum time (t) required for the release of liquid from a component served in a catastrophic spill is determined in accordance with the following equation:

$$(t)=(h/G)^{0.5}$$

where (t) is seconds, and (h) is the difference between the maximum height in feet of the contained liquid and the equilibrium height of liquid when impounded.

(4) Unless the requirements of paragraph (d) (5) of this section are met, the boiling rate of LNG on which (D_c) is based, is determined using either—

(i) The weighted average value of $(KPC)^{0.5}$ determined from eight representative experimental tests on the soil, sealant, and other contact surfaces in the impounding space; or

(ii) $(KPC)^{0.5}=20$, if the impounding surfaces outside the component served are covered with 6 inches of compacted sand and sealed as required by this part; where for the various contact surfaces:

K=thermal conductivity in (BTU/(hr) (ft) (F°)),
P=density in (lb/ft^3), and
C=heat capacity in (BTU/(lb) (F°)).

(5) If impounding surfaces are insulated as follows, the value of $(KPC)^{0.5}$ is determined in accordance with paragraph (d) (4) (i) of this section, both with and without the insulation system in place, using a value of $(KPC)^{0.5}$ of not less than the average of the weighted average value without insulation and the weighted average value with insulation:

(i) The insulation system is formed of multilayers of insulation;

(ii) Each layer is formed with separating or breakaway joints so that cracks or openings due to contraction from contact with the impounded liquid will be evenly distributed;

(iii) Each layer is contiguously interlocked in a manner which will ensure the integrity of its configuration in the event of a spill using fiberglass or metal mesh suitable for the temperature of the liquid to be impounded;

(iv) A suitable membrane with overlapping slip joints is installed between successive layers of insulation;

(v) Joints or breakway lines of successive layers of insulation are staggered in a manner which will provide adequate bearing for the membrane to withstand hydraulic loads and to minimize leakage of an impounded liquid thru the insulation;

(vi) The insulating material is anchored as necessary to prevent floatation; and

(vii) The impounding surface is rigorously inspected at intervals not exceeding 30 days and maintained in a manner to prevent degradation of its insulating properties due to exposure to the elements or other damage.

(6) Dispersion distance (D_c) is determined on the basis that vapor detention space does not exceed:

(i) For conditions described in paragraphs (d) (1) (ii) and (d) (2) (ii) of this section, all space provided for liquid impoundment and vapor detention outside the component served; and

(ii) For the conditions described in paragraph (d) (2) (i) of this section, all space provided for liquid impoundment and vapor detention outside the component served less the volume of liquid that would have entered the impounding space when generating vapor escapes the vapor detention barriers, assuming liquid to be entering the impounding space outside the component served at a constant rate over the time period prescribed by paragraph (d) (3) of this section.

(e) *Planned ignition.* An LNG facility need not have a dispersion exclusion zone if each impounding system which serves components containing LNG or flammable liquids with a boiling temperature of 98.6° F (37° C), or less, is equipped with a redundant automatic ignition system which—

(1) Assures ignition and combustion of combustible vapors at the impounding space; and

(2) Cannot be deactivated when the component served is in operation.

§ 193.111 Seismic investigation and design.

(a) Each operator shall determine the seismic response spectra, potential for motion amplification, potential for soil liquefaction, and potential for surface rupture at the site of each of the following LNG facilities based on a seismic investigation conducted in accordance with paragraph (b) of this section.

(1) A facility with an aggregate storage capacity of 250,000 barrels or more;

(2) A facility with an aggregate storage capacity of less than 250,000 barrels which is located in Zones 2, 3, and 4 of the "Seismic Risk Map of the United States," UBC, or Puerto Rico, not in-

cluding the capacity of any horizontal cylindrical double wall metal storage tank of less than 100,000 gallon capacity mounted within two feet of ground level that is located in Zone 2 of the UBC map; and

(3) A facility located where there is evidence indicating a potential for surface faulting.

(b) Each seismic investigation for facilities listed in paragraph (a) of this section must include the following:

(1) Data on each recorded earthquake which could reasonably be expected to have resulted in surface rupture or surface acceleration over (0.1g) in any direction at the site, including to the extent available:

(i) Date of occurrence;

(ii) Epicenter;

(iii) Hypocenter;

(iv) Highest intensity and its location;

(v) Highest surface response spectra, including both horizontal and vertical acceleration, and location;

(vi) Highest response spectra, including both horizontal and vertical acceleration, estimated to have occured at the site;

(vii) Surface faulting pertinent to potential surface faulting at the site; and

(viii) Uplift and subsidence pertinent to potential uplift and subsidence at the site.

(2) Location of each fault within 200 miles of the site, the length of which exceeds the minimum length shown below, where movement near the ground surface is determined to have occurred at least once in the past 35,000 years, movement is determined to have been recurring during the past 500,000 years, or where structural association with active faults could reasonably be expected to transfer potential motion to the site:

Distance from site (miles):	*Minimum length (miles)*
0 to 20	1
Above 20 to 50	5
Above 50 to 100	10
Above 100 to 150	20
Above 150 to 200	40

(3) A determination of the probability of surface faulting at the site.

(4) Correlation of epicenters, or locations of highest intensity, of recorded earthquakes with tectonic structures, or where the tectonic structure cannot be identified, with tectonic provinces located within 200 miles of the site.

(5) Determination of the:

(i) Geologic structure and conditions;

(ii) Geologic history;

(iii) Lithographic conditions;

(iv) Stratigraphic conditions;

(v) Hydrologic conditions;

(vi) The characteristics of materials underlying the site relative to transmitting seismic motions, including seismic wave velocities;

(vii) Comparative characteristics relative to transmission of vibratory motion to underlying materials at the site from the epicentral location or the location of maximum intensity of recorded earthquakes;

(viii) Estimated response spectra, including horizontal and vertical acceleration, with both 99.5 percent and 90 percent probability of not being exceeded in 50 years based on an analysis of all applicable geotechnical information and considering potential for motion amplification.

(c) In the case of LNG facilities not listed in paragraph (a) of this section, the critical components listed in paragraph (d) of this section must be designed and built to withstand—

(1) The horizontal seismic acceleration and other applicable factors set forth in the UBC, Volume 1, corresponding to the zone of the "Seismic Risk Map of the United States" in which the facility is located; and

(2) A vertical seismic acceleration equal to the horizontal acceleration and the associated applicable factors.

(d) In the case of LNG facilities listed in paragraph (a) of this section, the critical components set forth below must be designed and built to withstand the maximum horizontal and vertical response spectra estimated to have occurred at the site as a result of an earthquake investigated under paragraph (b)(2) of this section or the estimated response spectra with the following probability of not being exceeded in 50 years, whichever is larger, considering motion amplification and symmetric and asymmetric reaction forces resulting from hydrodynamic pressure and motions of contained liquids in interaction with the component structure:

Critical component:	*Probability of response spectra not being exceeded (percent)*
Storage tanks and their impounding systems	99.5
Transfer piping shutdown control systems, other flammable fluid containers	90

(e) Each container which does not have a structurally sound, liquid-tight cover, must have sufficient freeboard with an appropriate configuration to prevent the escape of liquid due to sloshing, wave action, and vertical liquid displacement caused by seismic motion.

(f) An LNG facility is prohibited in the following locations:

(1) A location where surface faulting near critical components is—

(i) Determined by the seismic investigation under paragraph (b) of this section to have more than a 0.5 percent probability of occurring within 50 years; or

(ii) Likely to have occurred within the past 35,000 years as indicated by geological evidence at or near the site or other information.

(2) A location where the estimated maximum horizontal or vertical seismic acceleration, or any combined vector thereof, occurring at the foundation of a critical component, has—

(i) For any critical component, exceeded 80 percent (g) in a recorded event; and

(ii) For the following critical components, more than the indicated percent probability of exceeding 80 percent (g) in 50 years:

Component:	*Probability (percent)*
Storage tank and their impounding systems	0.5
Transfer piping shutdown control system, other flammable fluid containers	10

(3) A location where soil liquefaction or landslide is predictable.

(g) If the estimated maximum seismic acceleration at a site has a 0.5 percent probability of exceeding 30 percent (g) in 50 years or exceeds 30 percent (g) based on a recorded earthquake, the following applies:

(1) Foundations of LNG storage tanks must be on bedrock.

(2) Impounding systems must be of types 1.1, 2.1, or 2.3, and surrounding grade elevation must be maintained not below the elevation at the top of the dike for a distance from the inner edge of the dike equal to $4(A)^{0.5}$, where A is the inside area across the top of the impounding space.

(3) Control systems must be provided to continuously monitor seismic response spectra and, when seismic acceleration equals 5 percent (g), automatically stop process operations, activate automatic shutdown valves on transfer lines, and shut down known ignition sources.

§ 193.113 Flooding.

(a) Each operator shall determine the effect of flooding at an LNG facility site which has a 99.5 percent probability of not being exceeded in 50 years. The determination must be based on—

(1) The volume and velocity of the floodwater;

(2) Floodwater previously recorded at the site;

(3) Predictable developments which would affect runoff and accumulation of water;

(4) Effect of dams;

(5) Annual rainfall in the local water shed;

(6) Rainfall and tidal action resulting from a hurricane; and

(7) Tsunamis.

(b) Each LNG facility must be located and designed so that the effect of the flooding determined under paragraph (a) of this section cannot reasonably be expected to result in a hazardous condition involving—

(1) Foundations;

(2) Impounding systems;

(3) Access from outside the facility or movement of personnel and equipment about the LNG facility site for the control of fires and other emergencies;

(4) Power supply to the facility;

(5) Operational capability of control systems, whether electrical, pneumatic or otherwise powered; or

(6) Structural integrity of critical components.

§ 193.115 Soil characteristics.

(a) Soil investigations including borings and other appropriate tests must be made at the site of an LNG facility to determine bearing capacity, settlement characteristics, potential for erosion, and other soil characteristics applicable to the integrity of an LNG facility.

(b) The soil characteristics at each LNG facility site must provide the following:

(1) Loadbearing capacities, using a safety factor of 1.3, which can support, without excessive lateral or vertical movement, all loads resulting from:

(i) Static and dynamic loading caused by—

(A) Components;

(B) The contents of components; and

(C) Movement of the contents of components, including flow, potential seiche from seismic action, filling, and rollover;

(ii) Static and dynamic loading caused by natural forces on components, including foundation toe loads due to wind forces; and

(iii) Static forces caused by hydrostatic testing of components.

(2) Properties which would not cause—

(i) Liquefaction of the soil under potential seismic action determined under § 193.111;

(ii) Excessive, erosion or frost heaves; and

(iii) Any other predictable unsafe condition.

§ 193.117 Wind forces.

(a) All critical components must be designed to withstand wind forces which have a 99.5 percent probability of not being exceeded in 50 years during storms other than tornadoes.

(b) In addition to the requirements of paragraph (a) of this section, if an LNG facility is located where tornadoes have at least a 0.5 percent probability of occurring within a 50-year period, or where the probability of tornadoes occurring cannot be accurately determined, storage tanks and dikes must be designed to withstand loading from sustained wind speeds of not less than 250 miles per hour, plus stress or impact which could result from the failure and collapse of all connected transfer piping and other appurtenances unless the connected transfer piping and appurtenances also are designed to withstand a wind speed of 250 miles per hour.

§ 193.119 Other severe weather and natural conditions.

(a) In addition to the requirements of §§ 193.111, 193.113, 193.115, and 193.117, each operator shall determine from historical records and engineering studies the worst combination of other weather and natural conditions which may predictably occur at an LNG facility site.

(b) The facility must be located and designed so that such severe conditions cannot reasonably be expected to result in a hazard involving the factors listed in § 193.113(b).

§ 193.121 Adjacent activities.

(a) Each opertaor shall determine the present and predictable activities adjacent to an LNG facility site that could adversely affect the operation of the LNG facility or the safety of persons or property located off the site if damage to the facility occurs.

(b) An LNG facility must not be located where present or projected offsite activities would be reasonably expected to—

(1) Adversely affect the operation of control systems;

(2) Cause failure of critical components; or

(3) Cause the LNG facility not to meet the requirements of this part.

§ 193.123 Separation of components.

Each LNG facility site must be large enough to provide for minimum separations between critical components and between components and the site boundary to—

(a) Permit predictable movement of personnel, maintenance equipment, and emergency equipment within and around the facility; and

(b) Minimize spill and collapse hazards to persons and property on and off the site, unless protection comparable to separation is provided.

Subpart C—Materials

§ 193.201 Scope.

This subpart prescribes requirements for the design of materials in a new LNG facility or an existing facility which is replaced, relocated, or otherwise changed.

§ 193.203 General.

Materials for all components must be—

(a) Able to maintain their structural integrity under all predictable loadings, including applicable environmental design forces under Subpart B of this part;

(b) Physically, chemically, and thermally compatible with any fluid they contain and with any other materials with which they are in contact; and

(c) Qualified in accordance with the applicable requirements of this subpart.

§ 193.205 Extreme temperatures; normal operations.

Each operator shall—

(a) Determine the range of temperatures to which components will be subjected during normal operations, including required testing, initial start-up, cooldown operations, and shutdown conditions; and

(b) Use component materials that meet the design standards of this part for strength, ductility, and other properties throughout the entire range of temperatures to which the component will be subjected in normal operations.

§ 193.207 Extreme temperatures; emergency conditions.

(a) Each operator shall determine the effects on components of a spill or other operational error which could allow LNG or cold refrigerant to reach a component which is not normally exposed to extreme cold.

(b) Each operator shall determine the effects on components of the extreme heat which would result if a spill of LNG or other flammable fluid were ignited.

(c) If the failure of a component due to extreme high or low temperature would result in an emergency, the component may not be used unless—

(1) It is made of materials which are compatible with the entire range of extreme temperatures to which the component may be subjected; or

(2) It is protected from the entire range of extreme temperatures to which the component may be subjected.

(d) If a material that has low resistance to flame temperatures is used in any component containing a flammable fluid, the material must be protected so that any heat resulting from a controllable emergency does not cause the release of fluid.

§ 193.209 Insulation.

Insulation on the outside of piping must be made of a material which will not support combustion in the installed condition and which will maintain adequate insulating properties when exposed to fire, heat, cold, water, or the force of fire hose streams.

§ 193.211 Cold boxes.

All cold boxes and their insulation must be made of materials which do not support combustion in the installed condition.

§ 193.213 Piping.

Piping made of cast iron, malleable iron, or ductile iron may not be used where service temperatures are below −20° F (−28.9° C).

§ 193.215 Concrete materials subject to LNG temperatures.

Concrete subject to LNG temperatures may not be used unless—

(a) Materials, measurements, mixing, placing, prestressing, and poststressing of concrete meets generally accepted engineering practices;

(b) Metallic reinforcing, prestressing wire, structural and nonstructural members used in concrete are acceptable in the installed condition for the temperature and stress levels encountered at design loading conditions; and

(c) Tests for the compressive strength, the coefficient of contraction, an acceptable thermal gradient, and, if applicable, acceptable surface loading to prevent spalling are performed on the concrete at the lowest predictable service temperature or similar test data on these properties are available.

§ 193.217 Combustible materials.

Insofar as practicable, each operator shall use noncombustible materials for the construction of buildings, plant equipment, and the foundations and supports of buildings and plant equipment in areas where ignition of the material would worsen a controllable emergency.

§ 193.219 Records.

Each operator shall keep a record of all components and their materials as necessary to verify that the design requirements of this part are complied with. These records must be maintained for the life of the component.

Subpart D—Design of Components

§ 193.301 Scope.

This subpart prescribes requirements for the design and installation of components in a new LNG facility or an existing facility which is replaced, relocated, or otherwise changed. The requirements are in addition to other design and installation requirements for individual components set forth in applicable subparts of this part.

§ 193.303 General.

(a) The components of each LNG facility must be designed, fabricated, and installed to withstand predictable loadings, including applicable environmental design forces under Subpart B of this part.

(b) Critical components which are exposed to the cold of an LNG or refrigerant spill or the heat of a fire may not worsen a controllable emergency.

(c) For the design and fabrication of an LNG facility, each operator shall use—

(1) With respect to design, persons who have demonstrated competence by training and experience in the design of components for use in an LNG facility; and

(2) With respect to fabrication, persons who have demonstrated competence by training and experience in the fabrication of components for use in an LNG facility.

§ 193.305 Valves.

(a) Each valve must be designed, manufactured, and tested according to written specifications based on generally accepted engineering practices to function under the full range of operating conditions, including pressure and temperature, that are predictable for the valve's use.

(b) Powered local and remote operation must be provided for valves that would be difficult or excessively time consuming to manually operate during a controllable emergency.

(c) When extended bonnet valves are used for cryogenic liquid service, stems must be above the horizontal.

(d) A relief valve to prevent overpressure must be installed in any section of flammable fluid piping which can be isolated between valves.

§ 193.307 Piping, general.

(a) Piping must be designed and manufactured according to written specifications based on generally accepted engineering practices to function under the full range of operating conditions, including pressure and temperature, that are predictable for the piping's use.

(b) All process and flammable fluid piping must have connections to facilitate blowdown and purging.

(c) Each piping system must be identified by color coding, painting, or labeling.

(d) To the extent practical, seamless pipe must be used for process and transfer piping handling LNG or other hazardous liquids.

(e) For longitudinal weld pipe handling LNG or flammable refrigerants—

(1) The design maximum pressure must result in stresses less than 50 percent of the maximum allowable stress set forth in Appendix A, Table 1 of ANSI B31.3, unless the weld is subjected to 100 percent radiographic or ultrasonic inspection to indicate any defects which could adversely affect the integrity of the weld or pipe; and

(2) The heat affected zone of the weld must comply with Section 323.2.2 of ANSI B31.3.

(f) Threaded pipe must be at leasts Schedule 80.

(g) Furnace lap weld, and furnace butt weld pipe may not be used for handling LNG or other hazardous liquids.

(h) Piping made of aluminum, copper, or a copper alloy may not be used where failure of such piping could result in a release of a hazardous volume of hazardous fluid.

§ 193.309 Pipe supports.

(a) Supports for piping whose stability is essential to prevent an emergency must be protected against the cold of a spill of LNG or refrigerant and the heat of any resulting fire.

(b) Supports for LNG or refrigerant piping must be designed to prevent excessive heat transfer which can result in either piping restraints caused by ice formations or the embrittlement of supporting steel.

§ 193.311 Buildings, design.

Each building or structural enclosure in which flammable fluids are handled must be designed and constructed to minimize the probability of initiating a blast wave by pressure containment, collapse of support members, and shrapnel-like fragmentation in the event of an explosion within the structure.

§ 193.313 Buildings, ventilation.

(a) Each building in which flammable fluids are handled must be ventilated to prevent the accumulation during normal operation of a combustible gas and air mixture, hazardous products of combustion, and other hazardous vapors in enclosed process areas, by one of the following means:

(1) A continuously operating mechanical ventilation system;

(2) A combination gravity ventilation system and normally off mechanical ventilation system which is energized by suitable combustible gas detectors at a concentration not exceeding 5 percent of the lower flammable limit of the gas;

(3) A dual rate mechanical ventilation system with the high rate energized by suitable gas detectors at a concentration not exceeding 5 percent of the lower flammable limit of the gas; or

(4) A gravity ventilation system composed of a combination of wall openings, roof ventilators, and if there are basements or depressed floor levels, a supplemental mechanical ventilation system.

(b) The ventilation rate must be at least one cubic foot per minute of air per square foot of floor area. If vapors heavier than air can be present, at least half of the ventilation must be from the lowest level exposed to such vapors.

§ 193.315 Low temperature.

(a) Each operator shall determine the effect of low temperatures produced by conduction of heat away from all components which are in contact with LNG, other cold fluids, or a cold environment in normal operation.

(b) Components made of noncryogenic materials must be protected from low temperatures which would impair the strength and ductility of the material.

(c) Valves and other moving components must not fail or become inoperable as a result of either the effect of low temperature on the materials or the formation of ice on the component.

§ 193.317 Expansion and contraction.

Each operator shall determine the amount of contraction and expansion of each component during operating and environmental thermal cycling and shall—

(a) Provide components that operate without detrimental stress or restriction of movement, within each component and between components, caused by contraction and expansion; and

(b) Prevent ice buildup from detrimentally restricting the movement of components caused by contraction and expansion.

§ 193.319 Frost heave.

(a) Each operator shall—

(1) Determine which critical components and their foundations could be endangered by frost heave from ambient temperatures or temperatures of the component; and

(2) Provide protection against frost heave which might impair their structural integrity.

(b) For each critical component and foundation determined under paragraph (a) of this section, instrumentation and alarm systems must be installed to warn of potential structural impairment due to frost heaving.

§ 193.321 Ice and snow.

(a) Components must support the weight of ice and snow which may collect or form on them.

(b) Each operator shall provide protection for components from falling ice or snow which may accumulate on structures.

§ 193.323 Electrical systems.

(a) Each operator shall—

(1) Determine the degree of hazard from electrical systems and equipment for the various areas within an LNG facility, including the possibility of an electrical ignition of combustible fluid and air mixtures that could occur from normal operations or from a leak or spill of flammable fluid; and

(2) Design and install electrical equipment and wiring in accordance with NFPA-70, to minimize the hazard, using explosion-proof equipment where necessary.

(b) In applicable areas, electrical grounding and bonding must be provided to prevent ignition from static electricity.

(c) If stray currents could be present or if impressed currents are used on transfer systems for cathodic protection, each operator shall take protective measures to prevent ignition from those sources.

(d) Ground circuit fault detection devices must be installed on all electrical equipment.

§ 193.325 Lightning.

Each operator shall install lightning rods, arrestors, and grounds as necessary to protect plant personnel from harm and critical components, including all electrical circuits, from damage as a result of a stroke of lightning.

§ 193.327 Boilers.

Boilers must be designed and fabricated in accordance with Section I of the ASME Boiler and Pressure Vessel Code. Other pressure vessels subject to that Code must be designed and fabricated in accordance with Division 1, or Division 2, Section VIII.

§ 193.329 Combustion engines and gas turbines.

Combustion engines and gas turbines must be installed in accordance with NFPA-37.

Subpart E—Impoundment Design and Capacity

§ 193.401 Scope.

This subpart prescribes requirements for the design and installation of impounding systems in a new LNG facility or an existing facility which is replaced, relocated, or otherwise changed.

§ 193.403 Impoundment required.

An impounding system must be provided for the following components and areas to contain a potential spill of LNG or other hazardous liquid:

(a) Storage tanks;

(b) Process equipment containing hazardous liquids;

(c) Gasification and vaporization equipment;

(d) Transfer piping;

(e) Cargo transfer systems;

(f) Parking areas for tank cars or tank trucks containing hazardous liquids; and

(g) Areas for loading, unloading, or storing portable containers of hazardous liquids.

§ 193.405 General design characteristics.

(a) An impounding system must have a configuration or design which will prevent liquid from escaping impoundment under the worst predictable spill condition by any predictable accidental mechanism, including leakage, trajectory (including splash from collapse of a component or part thereof), momentum and low surface friction, foaming, failure of pressurized piping, and accidental pumping.

(b) The basic form of an impounding system may be excavation, a natural geological formation, manufactured diking, such as bermes or walls, or any combination thereof.

§ 193.407 Classes of impounding systems.

(a) For the purpose of this part, impounding systems are classified as follows:

(1) *Class 1.* A system which surrounds the component served with the inner surface of the dike constructed against the outer surface of the component, consisting of the following types:

Type	*Description*
1.1	Excavation.
1.2	Berme.
1.3	Protective wall.
1.4	Nonprotective wall.

(2) *Class 2.* A system which surrounds the component served with the dike located a distance away from the component, consisting of the following types:

Type	*Description*
2.1	Excavation.
2.2	Berme.
2.3	Protective wall.
2.4	Nonprotective wall.
2.5	Protective wall, covered gas tight space filled with inert gas or interconnected with container vapor space.
2.6	Nonprotective wall, covered gas tight space filled with inert gas or interconnected with container vapor space.

(3) *Class 3.* A system which conducts a spill by dikes and floors to a remote impounding space which does not surround the component served, consisting of the following types:

Type	*Description*
3.1	Excavation.
3.2	Berme.
3.3	Protective wall.
3.4	Nonprotective wall.

NOTE.—The term "protective wall" means a dike is designed to comply with § 193.409 (a)(6).

(b) In the case of an impounding system consisting of a combination of Classes or types within a Class, where necessary to achieve compliance with requirements of this part applicable to a Class or type of system, those requirments apply according to the percentage of impoundment provided by each Class or type.

§ 193.409 Structural requirements.

(a) An impounding system, including any exposed surfaces of the component served which may be contacted by the liquid to be impounded, must be designed to prevent impairment of the system's performance ability and structural integrity as a result of the following:

(1) The imposed loading from—

(i) Full hydrostatic head;

(ii) Hydrodynamic action, including the effect of any material injected into the system for spill control;

(iii) The impingement of the trajectory of a liquid jet discharged at any predictable angle; and

(iv) Anticipated hydraulic forces from a rupture in a container or pressurized piping assuming that the discharge pressure from each failed component is its design maximum pressure.

(2) The erosive action from a spill, including jetting of spilling liquid, and any other anticipated erosive action including surface water runoff, ice formation, dislodgment of ice formation, and snow removal.

(3) The effect of the temperature, any thermal gradient, and any other anticipated degradation resulting from sudden or localized contact with the liquid to be impounded.

(4) Exposure to fire, where impoundment is intended for a flammable liquid or is subject to potential fire from sources other than an impounded liquid.

(5) If applicable, the potential impact and loading on the dike due to—

(i) Collapse of the component served or adjacent components; and

(ii) If the impounding system is under the landing pattern of a commercial or military airport or adjacent to railroad or highway traffic—

(A) Collision by aircraft or land vehicle; and

(B) An exploding aircraft or land vehicle.

(b) For spills from storage tanks, imposed loading and surging flow characteristics must be based on a sudden total release of the full contents of the tank. For spills from components other than storage tanks, imposed loading from the volume impounded must be based on the impounding capacities and conditions of discharge set forth in this part.

(c) Insulation, sealants, or other coatings and coverings which are nonstructural materials in an impounding system—

(1) Must not support combustion when in its installed condition;

(2) Must withstand exposure to fire from sources other than the liquid to be impounded; and

(3) Where such materials might be consumed during combustion of the impounded liquid, must not release toxic fumes.

(d) Insulation, sealants, and other coatings and coverings necessary for maintaining the functional integrity of an impounding system must be capable of withstanding exposure to fire, the liquid, and thermal shock from the liquid to be impounded.

§ 193.411 Impounding surfaces.

Surfaces of impounding systems must be treated and sealed where necessary to prevent—

(a) Leakage of the impounded liquid from the impounding system; and

(b) Seepage of surface water or ground water into the impounding space or into subsurface materials.

§ 193.413 Floors.

(a) Floors of Class 2 and Class 3 impounding systems must slope—

(1) Away from the component served to sump basins located as required by § 193.427; and

(2) To the extent feasible, away from the nearest adjacent critical component.

(b) Slopes of floors in Classes 2 and 3 impounding systems must have grades which—

(1) Are at least 2 percent;

(2) In the case of Class 3 systems, adequately provide for flow to the impounding space;

(3) Divert spilled liquids from the component served to sump basins installed under § 193.427 at the maximum feasible rate so as to minimize hazards from vapor evolution, fire, and other sources as a result of small spills; and

(4) Prevent collection of water and drain surface water from the floor at rates based on a maximum predictable rainfall and any other predictable water source.

(c) Floors in Classes 2 and 3 impounding systems must contain channels designed to minimize the wetted area and to drain surface water and spilled liquid to sump basins installed under § 193.427.

(d) Except where necessary for effective control of potential spills from transfer piping, impounding system floors must not be located above grade level.

§ 193.415 Dikes, general.

(a) Dikes must be reinforced and contiguously interlocked between all parts and the ground as necessary to withstand all hydrodynamic forces from a sudden total release of the highest density contents at full capacity of the component served, except that for dikes serving storage tanks with at least two load bearing cryogenic shells, hydrostatic forces in lieu of hydrodynamic forces may be applied.

(b) Penetrations in dikes to accommodate piping or any other purpose are prohibited.

(c) An outer wall of a component served by an impounding system may not be used as a dike.

§ 193.417 Vapor barriers.

(a) If a dispersion exclusion zone is provided under § 193.109, vapor barriers must be installed as necessary in connection with each impounding system for liquids with a boiling temperature of 98.6° F (37° C), or less, to detain the release of a spill vapor for a period which prevents a flammable gas cloud from extending beyond the exclusion zone boundary.

(b) Vapor barriers must be designed and constructed to entrain cold vapor.

§ 193.419 Dike dimensions.

(a) Except as provided in paragraph (c) of this section, dikes must have sufficient height and be located a sufficient distance from the component served to—

(1) Provide minimum impounding capacity as prescribed in this subpart and, in Class 3 systems, adequate flow capacity to the impounding space as required by § 193.445; and

(2) Intercept a jet of hazardous liquid discharged from any feasible location on the component served and at any predictable vertical and horizontal angle of exit and resulting trajectory, except that for low pressure storage tanks having multiple conventionally built vertical cylindrical walls with at least two such walls having full load bearing capability, vertical angles of discharge above the horizontal need not be considered.

(b) Dike height must be determined as a function of distance from the component served, assuming that wind will not influence the free parabolic trajectory of escaping liquid.

(c) Where dikes with dimensions prescribed by paragraph (a) of this section are impractical to provide, baffles or deflecting surfaces may be installed as necessary to control the trajectory of escaping liquid and to assure interception and confinement of the liquid in the impounding space.

§ 193.421 Covered systems.

(a) A type 2.5 or type 2.6 impounding system is prohibited unless it is—

(1) Sealed from the atmosphere and filled with an inert gas; or

(2) Permanently interconnected with the vapor space of the component served.

(b) The covering over an impounding space must be structurally capable of withstanding all potential internal and environmental loadings.

(c) Membraneous covering is prohibited.

(d) Instrumentation and controls must be provided, as applicable, to—

(1) Maintain pressures at a safe level;

(2) Monitor gas concentration; and

(3) Warn of unsafe conditions within the covered space.

(e) Pressure and vacuum relief devices, having adequate capacity, must be provided to assure that safe levels of pressure within the impounding space are not exceeded, assuming a spill results in the instantaneous wetting of 100 percent of the floor area and 50 percent of the inside area of the dikes.

(f) Dikes must have adequate structural strength to assure that they can withstand impact from a collapsed cover and all anticipated conditions which could cause a failure of the impounding space cover.

§ 193.423 Gas leak detection.

Impounding systems must be equipped with instruments to continously monitor the following locations for the presence of gas concentrations and to warn when concentration levels exceed 20 percent of the lower explosive limit:

(a) The low point in each quadrant of an impounding space;

(b) All sump basins;

(c) In a Class 3 system, the point where conducting dikes join the impounding space;

(d) Appropriate points along each dike at intervals not more than 100 feet; and

(e) Other appropriate points where collection or passage of leaking gas could be expected.

§ 193.425 Inerting systems.

(a) Each open impounding system must have an inerting device installed for each length of diking which—

(1) Has an average dike height greater than one half the distance between the dike and an opposite barrier of equal or greater height; and

(2) Is longer than the distance to an opposite barrier but not longer than twice the distance.

(b) Each inerting device must continuously measure gas concentrations and automatically release an inert mixture of carbon dioxide and nitrogen gases when a gas concentration equal to 40 percent of the lower flammable limit is detected.

(c) The concentration of gas must be measured, at each low elevation in the impounding space where dense gas is most likely to collect.

(d) The inert mixture must be injected at an elevation of 50 percent of dike height horizontally in a direction to prevent direct impingement on the gas concentration sampling location.

(e) The specific gravity of the inert mixture when injected must be maintained at 1.15 to 1.20, based on an air temperature of 32° F (0° C).

(f) The supply of inert mixture available for injection must be to fill at least 40 percent of the portion of the impounding space outside the component served.

§ 193.427 Sump basins.

(a) Except for Class 1 impounding systems, a sump basin must be located in each impounding system to hold small spills of flammable liquids and to provide for the transfer of such liquids from an impounding system.

(b) Each sump basin must be located at the point most remote from the component served by the impounding system and any adjacent aboveground critical component.

§ 193.429 Spill removal.

(a) Each sump basin must be equipped with transfer piping, with cryogenically suitable pumps and piping and redundant failsafe arrangements to prevent inadvertent operation, for transferring spilled liquid to a receiving vessel.

(b) The transfer piping must provide for selective withdrawal from multiple locations and be appropriately insulated so that flammable liquid can be withdrawn from the impounding space during a fire in the impounding space.

§ 193.431 Water removal.

(a) Impounding systems must have sump pumps and piping running over the dike to remove water collecting in the impounding space, including the sump basin.

(b) The water removal system must have adequate capacity to remove water at rates which equal the maximum predictable collection rate from rainfall and other natural sources.

(c) Sump pumps for water removal must—

(1) Automatically operate as necessary to keep the impounding space as dry as possible; and

(2) Have controls for operation and redundant automatic shutdown controls to prevent operation when the liquid to be impounded is present.

§ 193.433 Shared impoundment.

(a) Except as provided in paragraph (c) of this section, a single impounding system may not serve more than one component if—

(1) The maximum spill capacity of any single component exceeds 2,000 barrels; or

(2) The maximum spill capacity of all components exceeds 10,000 barrels.

(b) If more than one component is served by a single impounding system—

(1) Twice the minimum separation distances prescribed by § 193.123 must be provided; and

(2) Components must be protected by topography or other means (excluding water deluge or other action which could result in the dispersion distance of a combustible gas exceeding acceptable limits) to prevent spillage from one component from causing damage or leakage to any other component due to any of the following:

(i) Fire exposure;

(ii) Low temperatures;

(iii) Chemical reactions; or

(iv) High thermal gradients or physical forces which could result from contact with LNG in the event of a sudden total spill of the maximum capacity of liquid from any component, trajectories from jets of leaking liquids, or other forms of leakage.

(c) Where components have at least two load bearing cryogenic shells, with the outer shell made of cryogenic steel alloy or cryogenic prestressed concrete, the aggregate maximum capacity of components within a single impounding system may be increased to 250,000 barrels by increasing either the size or number of components.

§ 193.435 Other components and materials.

Piping, pipe supports, and critical components located within an impounding system must be protected against damage from fire, contact with spilled liquids, or impact by failed components which could result in an emergency.

§ 193.437 Impoundment capacity: general.

(a) For Types 2.5 and 2.6 impounding systems, space between the outer wall of the component served and the dike may not be used to comply with the capacity requirements of this subpart which exceed the component's maximum liquid capacity unless the impounding space and the component are covered by an impounding space roof which is separate and independent from the component.

(b) In addition to capacities otherwise required by this subpart, an impounding system must have sufficient volumetric capacity to provide for—

(1) Displacement by components; and

(2) Displacement which could accumulate when a higher density substance (e.g., water used in fire fighting) enters the system, considering any excess impounding capacity, evaporation, fire by automatic planned ignition under § 193.109(f), and other relevant means assuring capacity.

§ 193.439 Impoundment capacity; storage tanks.

Each impounding system serving a storage tank must have a minimum volumetric liquid impoundment capacity as follows:

Number of tanks in system	Class or type of system	System capacity of tank's maximum liquid capacity: Hazardous liquids with a boiling point of 98.6° F (37° C) or less at 1 bar absolute pressure	Other hazardous liquids
1	Class 1 and types 2.5 and 2.6	120 percent	110 percent.
	Class 3 and types 2.1 to 2.4	150 percent	120 percent.
More than 1	All	100 percent of all tanks or 150 percent of largest tank, whichever is greater.	100 percent of the largest 2 tanks or 120 percent of the largest tank, whichever is greater.

§ 193.441 Impoundment capacity; equipment and transfer facilities.

Each impounding system serving a component under §§ 193.403 (b)–(e) must have a minimum volumetric liquid impoundment capacity equal to the sum of—

(a) 150 percent of the volume of liquid that could be contained in the component served; and

(b) The maximum volume of liquid which could discharge into the impounding space from any single failure of equipment or piping during twice the time period necessary for spill detection, instrument response, and sequenced shutdown by the redundant automatic shutdown system under § 193.605.

§ 193.443 Impoundment capacity; parking areas portable containers.

Each impounding system serving a component under §§ 193.403 (f) and (g) must hve a minimum volumetric liquid impoundment capacity which complies with the requirements of § 193.437, assuming each tank car, tank truck, or portable container to be a storage tank.

§ 193.445 *Flow capacity in class 3 impounding systems.*

(a) Each spill conducting space in a Class 3 impounding system must have adequate flow capacity for the following volumes and flow rates of a potential spill at all points along its traverse:

(1) For storage tanks, the worst combination of flow rates and 150 percent of the volume from a sudden and complete release of the largest above grade maximum liquid capacity of any single tank served, plus the discharge from all transfer piping which could be loading that tank, assuming the loading transfer piping is discharging at maximum potential open end capacity during the longer of the time periods set forth in § 193.439(b), and less any upstream or intermediate impounding capacity.

(2) For components listed in §§ 193.403 (b)–(e), the worst combination of flow rates and volumes determined in accordance with § 193.439, less any upstream or intermediate impounding capacity.

(3) For areas listed in §§ 193.403 (f) and (g), the requirements of paragraph (a)(1) of this section apply, assuming each tank car, tank truck, or portable container to be a storage tank.

(b) When intermediate impounding space is used to provide the capacity of conducting space required by this section, the capacity of the intermediate space must be based on the combination of applicable volumes and flow rates set forth in paragraph (a) of this section to assure adequate capacity of the conducting space.

§ 193.447 Sump basin capacity.

(a) Sump basins in impounding systems for storage tanks must have a minimum volumetric capacity equal to the discharge from relevant connected sections of transfer piping which can operate simultaneously, assuming the transfer piping discharges at maximum potential open end capacity for the time period necessary for spill detection instrument response and sequenced shutdown by the redundant automatic shutdown system.

(b) Sump basins in impounding systems for components listed in §§ 193.403 (b)–(e) must have a minimum volumetric capacity equal to half of the lesser of—

(1) The volume of liquid which could discharge into the impounding system from any single failure of equipment or piping during the time period necessary for spill detection instrument response and sequenced shutdown by the redundant automatic shutdown system; or

(2) The volume of liquid that could be contained in the component served.

(c) Sump basins in impounding systems for areas listed in §§ 193.403 (f) and (g) must have a minimum volumetric liquid capacity which meets the requirements of paragraph (a) of this section, assuming each tank car, tank truck, or portable container to be a storage tank.

Subpart F—Storage Tanks

§ 193.501 *Scope.*

This subpart prescribes requirements for the design and installation of storage tanks in a new LNG facility or an existing facility which is replaced, relocated, or otherwise changed.

§ 193.503 General.

(a) Storage tanks must comply with the requirements of this subpart and the other applicable requirements of this part.

(b) A membrane liner may not be used as an inner container in a storage tank.

§ 193.505 Loading forces.

Each component of a storage tank must be designed to withstand any predictable combination of the following forces which would result in the highest stress to the component:

(a) Design maximum pressure determined under § 193.513.

(b) Design minimum pressure determined under § 193.515.

(c) Weight of the structure.

(d) Weight of liquid to be stored determined at its highest density and at the level creating the highest stress.

(e) Nonuniform reaction forces on the foundation due to settling and other movement.

(f) Superimposed forces from piping, stairways, and other connected appurtenances.

(g) Snow and ice.

(h) The loading of internal insulation on the inner container and outer shell due to weight and movement of the container and shell over the design life of the insulation.

(i) In the case of vacuum insulation, the forces due to the vacuum.

(j) In the case of a positive pressure purge, the forces due to the maximum positive pressure of the purge gas.

§ 193.507 Stratification.

Storage tanks for cryogenic liquids with a capacity of 5,000 barrels or more must be equipped with—

(a) Mixing devices for liquid loading to mitigate a potential for rollover and overpressure resulting in relief valve operation; and

(b) Pumps, piping, and valves for—

(1) Selective filling at the top and bottom of the tank;

(2) Circulating liquid from the bottom to the top of the same tank; and

(3) Transferring liquid selectively from the bottom of the tank to the bottom and top of any adjacent storage tank for the same liquid.

§ 193.509 Movement and stress.

(a) Each operator shall determine for normal operations of each storage tank—

(1) The amount and pattern of predictable movement of components, including transfer piping, and the foundation, which could result from thermal cycling, loading forces, and ambient air changes; and

(2) For a storage tank with an inner container, the predictable movement of the inner container and the outer shell in relation to each other.

(b) Storage tanks must be designed to provide adequate allowance for stress due to movement determined under paragraph (a) of this section, including provisions that—

(1) Backfill does not cause excessive stresses on the tank structure due to expansion of the storage tank during warmup;

(2) Insulation does not settle to a damaging degree or unsafe condition during thermal cycling; and

(3) Expansion bends and other expansion or contraction devices are adequate to prevent excessive stress on tank penetrations, especially during cooldown from ambient temperatures.

§ 193.511 Penetrations.

(a) All penetrations in a storage tank must be symmetrically located on the top of the tank as close as possible to the center.

(b) Penetrations must be reinforced to ensure that any failure of the penetrating component does not result in hazardous structural damage to the tank.

§ 193.513 Overpressure.

(a) Each operator shall determine the design maximum pressure at the top of each storage tank.

(b) The design maximum pressure of a storage tank may not be lower than the highest vapor pressure resulting from each of the following events or combination thereof that predictably might occur:

(1) Filling the tank with any cryogenic or refrigerant liquid, including effects of increased vaporization rate due to superheat and sensible heat of the added liquid;

(2) Rollover resulting from adding a cryogenic liquid which has a different density than liquid already in the tank, or from weathering in storage;

(3) Fall in barometric pressure, using the worst combination of amount of fall and rate of fall which might credibly occur;

(4) Loss of effective insulation that may result from an adjacent fire, leak of liquid into the inter-tank space, or other predictable accident; and

(5) Flash vaporization resulting from pump recirculation.

(c) To prevent a storage tank from exceeding its design maximum pressure, each operator shall use automatic primary and redundant relief devices, a mixing system, operating procedures, and—

(1) Boiloff extraction systems with reliquefaction or sendout systems; or

(2) Liquid subcooling.

§ 193.515 Underpressure.

(a) Each operator shall determine the design minimum pressure at the top of each storage tank.

(b) The design minimum pressure may not be lower than 2 psig or higher than the lowest vapor pressure resulting from each of the following events or combinations thereof that predictably might occur:

(1) Withdrawing liquid from the tank;

(2) Withdrawing gas from the tank;

(3) Adding subcooled cryogenic liquid to the tank; and

(4) Rise in barometric pressure, based on the worst combination of amount of rise and rate of rise which predictably might occur.

(c) Each operator shall use automatic primary and redundant relief devices, operating procedures, and gas makeup or ambient vaporizers to prevent the pressure in a storage tank from falling below the design minimum pressure. Air must not enter the tank except when necessary to protect the tank in the event of a malfunction of relief devices.

§ 193.517 External temperature.

(a) Each operator shall determine the maximum exposure of a storage tank to—

(1) Conduction of cold by transfer piping connection;

(2) Contact with spilled LNG or liquid refrigerant and cold vapor caused by a failure of connecting piping; and

(3) Heat from an ignited spill of LNG or other flammable liquid caused by a failure of connecting piping.

(b) Each storage tank must be protected to ensure that the cold of any cryogenic or refrigerant liquid spill and the heat of any resulting fire will not cause the storage tank to add significantly to a controllable emergency.

§ 193.519 Internal temperature.

Each storage tank must be designed to withstand the lowest temperature to which it could be subject below the temperature of the liquid contained at the design minimum pressure.

§ 193.521 Foundation.

(a) Each storage tank must have a stable foundation designed in accordance with generally accepted structural engineering practices. The design must take into account the forces which may exist due to the difference in density between the contained liquid and the displaced ground.

(b) Each foundation must support the loading forces under § 193.505 without detrimental settling that could impair the structural integrity of the tank.

(c) When the location of a storage tank foundation is subject to flooding or is near the natural water table, each operator shall determine the weight of the foundation and the empty tank and shall anchor the tank so that the buoyant water forces will not float the tank or impair the structural integrity of the tank.

(d) Piling must not be used to provide necessary foundation support for a storage tank.

§ 193.523 Frost heave.

If the protection provided for storage tank foundations from frost heave under § 193.319(a) includes heating the foundation area—

(a) The instrumentation and alarm system provided under § 193.319(b) must include an alarm to warn of malfunction of the heating system; and

(b) A means to correct the malfunction must be provided.

§ 193.525 Insulation.

(a) Insulation on the outside of a storage tank may not be used to maintain stored liquid at an operating temperature.

(b) Insulation on the outside of a storage tank must be covered and must provide a vapor barrier, be free of water, and meet the other applicable requirements of this part. The covering must be inflammable, have a melting point above 1500° F, not be subject to ultraviolet decay, and withstand wind and anticipated impact loading which credibly may occur.

(c) Insulation between an inner container and the outer shell of a storage tank must be compatible with the contained liquid and its vapor. The insulation, in its installed condition, must be inflammable. The insulation must not significantly lose insulating properties by melting, settling, or other means if a fire occurs outside the outer shell.

§ 193.527 Instrumentation for storage tanks.

(a) Each storage tank must be equipped with redundant sensing devices and personnel warning devices, as prescribed, which operate continuously while the tank is in operation to assure that each of the following conditions is not a potential hazard to the structural integrity or safety of the tank:

Condition	Instrumentation
(1) Amount of liquid in the tank	Liquid level gages and recorders with top fill alarms and a separate overfill alarm.
(2) Vapor pressure within the tank	Pressure gages and recorders with high-pressure alarms.
(3) Temperatures at representative critical points in the foundation.	Temperature indicating and recording devices with alarm at 37° F (2.8° C).
(4) Temperatures of contained liquid at various vertical intervals.	Temperature recorders.
(5) Reaction loading between an LNG tank and foundation.	Load recorders plus pressure cells at each critical location distributed along orthogonal axes under the tank.
(6) Excessive stress in tank structures	Strain recorders with sensors located at representative critical points.
(7) Air in tank due to vacuum relief valve	Oxygen concentration indicator with alarm at 0.5 pct by volume.
(8) Gas under tank	Gas concentration indicator with alarm at 5 pct of the lower flammable limit.

(b) Each storage tank must be designed as appropriate to provide for compliance with the inspection requirements of § 193.1219.

§ 193.529 Metal shells and containers.

(a) Metal shells and containers in storage tanks with design maximum pressures of not more than 15 psig must be designed in accordance with API Standard 620 and, where applicable, Appendix Q of that Standard.

(b) Metal shells and containers in storage tanks with design maximum pressures above 15 psig must be designed in accordance with the applicable Division of Section VIII of the ASME Boiler and Pressure Vessel Code.

§ 193.531 Concrete shells and containers.

(a) Concrete shells and containers in storage tanks must be designed and constructed in accordance with ACI-318-71 and ACI-67-40.

(b) Design stresses for concrete must be based upon strength values determined at 60° F.

§ 193.533 Thermal barriers.

Thermal barriers must be provided between piping and an outer shell when necessary to prevent the outer shell from being exposed to temperatures lower than the design temperature.

§ 193.535 Support systems.

(a) Saddles and legs must be designed in accordance with generally accepted structural engineering practices, taking into account loads during transportation, erection loads, and thermal loads.

(b) Storage tank stress concentrations from support systems must be minimized by distribution of loads using pads, load rings, or other means.

(c) For a storage tank with an inner container, support systems must be designed to—

(1) Minimize thermal stresses imparted to the inner container and outer shell by expansion and contraction; and

(2) Sustain the maximum applicable loading from shipping and operating conditions.

(d) The bottom of a storage tank with a capacity more than 15,000 barrels may not be installed above grade level.

§ 193.537 Internal piping.

(a) Piping between an inner container and outer shell must be designed for not less than the pressure rating of the inner container. The piping must contain expansion loops where necessary to protect against thermal and other secondary stresses created by operation of the tank. Bellows may not be used within the space between the inner container and outer shell.

(b) Storage tanks with a design pressure which exceeds the liquid head from the maximum liquid level to the top of the tank must be equipped with internal excess flow valves.

§ 193.539 Marking.

(a) Each operator shall install and maintain a placard in an accessible place on each storage tank and mark it with the following, using English and metric units where applicable:

(1) Builder's name;

(2) Date construction completed, and date of commissioning;

(3) Nominal liquid capacity stated in barrels, gallons, and cubic meters;

(4) Design pressure for vapor at top of tank;

(5) Maximum density of liquid to be stored;

(6) Maximum level to which container may be filled with stored liquid;

(7) Maximum design soil load bearing;

(8) Maximum design foundation reaction forces on tank;

(9) Minimum temperature, in degrees Fahrenheit and Celsius, for which the tank was designed;

(10) Maximum external water height which does not result in excessive flotation forces or other damaging stresses prohibited under § 193.521(c); and

(11) Maximum design wind load, snow load, and ice load.

(b) Each penetration in a storage tank must be marked indicating the function of the penetration.

(c) Marking required by this section must not be obscured by frosting.

Subpart G—Design of Transfer Systems

§ 193.601 Scope.

This subpart prescribes requirements for the design and installation of transfer systems in new LNG facilities or existing facilities which are replaced, relocated, or otherwise changed.

§ 193.603 General.

(a) Transfer systems must comply with the requirements of this subpart and the other applicable requirements of this part.

(b) The design of transfer systems must provide for expansion and stress due to the frequency of thermal cycling and intermittent use to which the transfer system may be subjected, including the following:

(1) Where the system is not maintained at a temperature near its operating temperature, expansion loops must be used to minimize stresses resulting from thermal changes;

(2) Bellows type expansion joints may not be used unless the system is maintained at a temperature near its operating temperature;

(3) Slip type expansion joints are prohibited;

(4) A suitable means must be provided to precool the piping in a manner that prevents excessive stress before transferring cold fluids; and

(5) Stress due to thermal and hydraulic shock must be determined and accommodated by the strength of materials, dash pots, or the operating speed of valves, as necessary.

§ 193.605 Shutdown control system.

(a) Each transfer sytem must be equipped with an automatic redundant shutdown control system to minimize the amount of fluid which could discharge from the transfer system in the event of a failure. The control system must automatically shutdown appropriate valves and pumping equipment and provide automatic bleed when any of the following occurs:

(1) A piping failure;

(2) Overfilling the receiving vessel;

(3) Pressure outside the limits of the maximum and minimum allowable operating pressure;

(4) Temperature outside the range determined under § 193.205;

(5) Gas concentrations in the atmosphere exceeding 20 percent of the lower flammable limit; or

(6) A sudden flow change, pressure loss, or other condition indicating an accidental spill or potential spill.

(b) Transfer shutdown control systems must be power and manually operable at the valve and power operable at a location at least 50 feet from the valve.

(c) Shutoff valves much be located:

(1) At the inlet of each gasifier;

(2) On fluid return lines and on manifolds used in bulk transfer;

(3) At the connection of a transfer system with a pipeline;

(4) Near the extremities of each transfer system; and

(5) At any other location necessary to control a spill to comply with impounding and exclusion distance requirements of this part.

(d) Shutoff valves must be designed and installed so excessive strain in the piping system does not excessively stress the shutoff seats of the valves.

§ 193.607 Backflow.

Each transfer system must operate with a means to—

(a) Prevent backflow of liquid from a receiving vessel from causing a hazardous condition; and

(b) Maintain one-way flow where necessary for the integrity or safe operation of the LNG facility.

§ 193.609 Overfilling.

(a) Each transfer system must operate with a means to prevent overfilling of receiving vessel without manual intervention. The means must include—

(1) Setting a transfer system to pump a predetermined amount of liquid into a receiving vessel and to stop the transfer when that amount has been pumped;

(2) When the amount of liquid in the receiving vessel reaches the design load limit, activitation of the automatic shutdown system installed under § 193.605; or

(3) Transferring any overflow of liquid to an alternate receiving vessel.

(b) Each transfer system must be equipped with a means which alerts personnel when the amount of liquid in a receiving vessel approaches its design load limit. The alert must be given in time for the personnel to monitor the automatic shutoff and to safely terminate the transfer by manual operation if necessary.

§ 193.611 Cargo transfer systems.

Each cargo transfer system must have—

(a) A means of safely depressuring and venting each transfer line before disconnection;

(b) A means of safely purging each transfer line in which a significant amount of combustible mixture could remain after it is disconnected;

(c) In the case of hoses and arms, a design for—

(1) Operating temperatures encountered during transfers; and

(2) A bursting pressure of not less than five times the operating pressure;

(d) On transfer connections which operate at temperatures below −60° F (−51.1° C), flexible metallic hoses or pipe and swivel joints;

(e) Adequate support for transfer piping connections, taking into account potential ice formation;

(f) Connections which are designed for the operating temperatures and pressures encountered during transfers, and the anticipated frequency of any coupling and uncoupling;

(g) Return lines for vapor and gas to safely provide for displacement during transfer;

(h) A signal light at each control location of remotely located pumps or compressors used for transfer which indicates whether the pump or compressor is idle or in operation; and

(i) A means of communication between loading or unloading areas and any remotely located areas in which personnel are associated with the transfer operations.

§ 193.613 Marine transfer.

(a) For marine transfer, each transfer line must be equipped with an isolation valve located on shore near the approach to the pier or dock.

(b) Each operator shall provide that the general cargo handling and ship bunkering facilities on a marine pier do not present a hazard to transfer operations. The protection must include one of the following—

(1) Fixed transfer lines; or

(2) Adequate separation between transfer lines and the cargo handling and bunkering facilities to prevent an accident at the bunkering facilities from endangering the cargo transfer system.

(c) Underwater piping must be located or protected so that it is not exposed to damage from marine traffic.

§ 193.615 Tank car and tank truck transfer.

(a) For tank car and tank truck transfer operations, transfer procedures must be located at the transfer area.

(b) The transfer area must be designed to accommodate tank cars and tank trucks without excessive maneuvering. Tank trucks must exit the transfer area without backing.

(c) A cargo transfer system must be designed to prevent operation until the receiving tank vehicle is properly immobilized and secure.

§ 193.617 Emergency valve.

In addition to other valving required by this part, a cargo transfer system must be equipped with a shutoff valve for each liquid and each vapor line, including a common line to multiple transfer areas, located away from the transfer area where it can be operated readily during a controllable emergency.

Subpart H—Gasification Equipment

§ 193.701 Scope.

This subpart prescribes requirements for the design of gasification equipment in a new LNG facility or an existing facility which is replaced, relocated, or otherwise changed.

§ 193.703 General.

Gasifiers must comply with the requirements of this subpart and the other applicable requirements of this part.

§ 193.705 Fired gasifiers.

Fired gasifiers must be designed and fabricated in accordance with Section VIII, Division I, of the ASME Boiler and Pressure Vessel Code.

§ 193.707 Downstream pressure.

(a) The pressures in piping and equipment located downstream from each gasifier must be continuously monitored.

(b) Each operator shall provide an automatic control system to—

(1) Limit the flow of gas from a gasifier to a rate which will not overpressure downstream piping or equipment; and

(2) Limit the flow of LNG to the gasifier to a rate which will not overpressure the gasifier.

§ 193.709 Downstream temperature.

(a) Each operator shall determine the extremes of high and low temperature which equipment and piping located downstream from a gasifier can accept without adversely affecting its structural integrity or safety.

(b) Each operator shall provide an automatic control system to prevent the flow of gas or liquid from a gasifier at a temperature which will adversely affect the structural integrity or safety of the equipment or piping located downstream. The control system must be independent of all other flow control systems and must incorporate a line valve not used for any other purpose.

§ 193.711 Operational control.

(a) Gasifiers must be equipped with devices which monitor the temperature and pressure of the LNG and natural gas in the gasifiers.

(b) The rate of gasification must be maintained automatically to ensure that the temperature and pressure of LNG and natural gas are within the design limits of the gasifier.

(c) The gasifier must be operated in accordance with procedures designed to prevent thermal shock during the initiation of gasification.

(d) Each LNG facility must have control systems to stop the flow of LNG and other flammable fluids to gasifiers and related equipment when an emergency occurs in or near a gasifier.

(e) Manifold gasifiers must be equipped with two inlet valves in series to prevent LNG from entering an idle gasifier and a means to remove LNG which accumulates between the valves.

§ 193.713 Shutoff valves.

(a) Each shutoff valve located on transfer piping supplying LNG to a gasifier must meet the following applicable requirements—

(1) The valve must be near the gasifier;

(2) If the gasifier is installed in a building, the valve must be located outside the building near the emergency exit; and

(3) When the valve is located near an LNG container or in a place which would be inaccessible during a controllable emergency, the valve must also have an automatic control ssytem that will close the valve upon loss of pressure in the inlet line (excess flow); abnormally high temperature (fire); or low temperature liquid or gas downstream of the gasifier.

(b) A shutoff valve must be located on each outlet of a gasifier.

(c) If a gasifier heater is located in a building, a shutoff control must be located outside the building near an emergency exit.

(d) For gasifiers designed to use a flammable intermediate fluid, a shutoff valve must be located on the inlet and outlet line of the intermediate fluid piping system where they will be operable during a controllable emergency involving the gasifier.

§ 193.715 Relief devices.

The capacity of pressure relief devices required for gasifiers by § 193.905(b) is governed by the following:

(a) For heated gasifiers, the capacity must be at least 110 percent of rated natural gas flow capacity without allowing the pressure to rise above the gasifier's design maximum pressure.

(b) For ambient gasifiers, the capacity must be at least 150 percent of rated natural gas flow capacity without allowing the pressure to rise above the gasifier's design maximum pressure.

§ 193.717 Warning devices.

Each building which houses a gasifier or gasifier heater must have warning devices to alert personnel automatically of hazardous flammable mixtures or thermal radiation in the building.

§ 193.719 Combustion air intakes.

(a) Combustion air intakes to heated gasifiers and gasifier heaters must prevent the induction of a flammable mixture during normal operations.

(b) If a heated gasifier or gasifier heater is located in a building, the combustion air intake must be located outside the building.

Subpart I—Liquefaction Equipment

§ 193.801 Scope.

This subpart prescribes requirements for the design of natural gas liquifaction equipment in a new LNG facility or an existing facility which is replaced, relocated, or otherwise changed.

§ 193.803 General.

Liquefaction equipment must comply with the requirements of this subpart and the other applicable requirements of this part.

§ 193.805 Control of incoming gas.

A shutoff valve must be located on piping delivering natural gas to liquefaction equipment. Each valve must be actuated automatically by a shutdown control system—

(a) When a mixture of natural gas and air in the LNG facility near liqufaction equipment reaches 30 percent of the lower flammable explosive limit; and

(b) When an uncontrolled fire occurs in the LNG facility.

§ 193.807 Contaminants.

Each operator shall provide a means of—

(a) Monitoring the incoming gas to ensure that detrimental contaminants are removed; and

(b) Detecting an unsafe condition due to buildup of ice or other contaminants in the liquefaction equipment.

§ 193.809 Reverse flow.

Each multiple parallel piping system connected to liquefaction equipment must have devices to prevent reverse flow detrimental to safe operation of the liquefaction equipment.

§ 193.811 Cold boxes.

Each cold box in liquefaction equipment must be equipped with a means of detecting the concentration of natural gas in air in the insulation space. If the concentration reaches 5 percent of the lower flammable limit, purge gas must be introduced to reduce the concentration.

§ 193.813 Air in gas.

Where incoming gas to liquefaction equipment contains air, each operator shall provide a means of preventing a flammable mixture from occurring under any operating condition.

§ 193.815 Equipment supports.

Supports for liquefaction equipment must be protected against fire exposure or be protected against cold liquid, or both, if they are subject to such exposures.

Subpart J—Control Systems

§ 193.901 Scope.

This subpart prescribes requirements for the design and installation of control systems in a new LNG facility or an existing facility which is replaced, relocated, or otherwise changed.

§ 193.903 General.

(a) Control systems must comply with the requirements of this subpart and other applicable requirements of this part.

(b) Each control system must be capable of performing its design function under normal operating conditions, and in a controllable emergency to the extent that performance of that function is necessary to prevent a hazard from occurring.

(c) Control systems must be accessible for maintenance, including inspection and testing to verify their operating capability.

§ 193.905 Relief devices.

(a) Each operator shall determine—

(1) The pressures in components which may result from the closing of each control valve or combination of valves, taking into account the trapping of LNG or other fluid between valves; and

(2) The maximum rates of boiloff and expansion of fluid which may occur in each component during normal operation, particularly cooldown, and controllable emergencies.

(b) Each component containing a hazardous fluid must be equipped with automatic redundant relief devices which will release the contained fluid at a rate sufficient to limit the pressure in the component to not more than the design maximum pressure and not less than design minimum pressure.

(c) Manual overrides must be provided on relief devices for emergency operation.

(d) Relief devices must have vents installed in a manner to prevent a release of fluid from—

(1) Causing an emergency; and

(2) Worsening a controllable emergency.

(e) Primary vacuum relief devices must not let air into a component containing a flammable fluid.

(f) The set-point pressures of all adjustable relief devices must be sealed.

(g) Relief devices which are installed to limit minimum or maximum pressures may not be used to handle boiloff and flash gases generated in the normal operations of a component.

(h) During normal operation, relief devices may not be subjected to temperatures higher than temperatures at which they are designed to operate.

§ 193.907 Vents.

(a) Flammable fluids may not be vented into the atmosphere of a building.

(b) Discharge vents may not draw in air during operation.

§ 193.909 Sensing devices.

(a) Each operator shall determine the appropriate location for and install sensing devices as necessary to—

(1) Monitor the operation of components to detect a malfunction which could cause a hazardous condition if permitted to continue; and

(2) Detect the presence of fire and combustible gas in locations determined under § 193.1305(a)(2).

(b) Buildings in which flammable fluids are used or handled must be continuously monitored by gas sensing devices set to sound an alarm in the building and at the control center when the concentration of the fluid in air is not more than 5 percent of the lower flammable limit.

§ 193.911 Warning devices.

Each operator shall install warning devices in the control center and at other locations frequented by personnel to warn of potential or existing hazardous conditions detected by all sensing devices required by this part. Warnings must be given both audibly and visibly and must be designed to gain the attention of personnel. Warnings in the control center must indicate the location and cause of the existing or potential hazard.

§ 193.913 Discharge pressures and temperatures.

Sensing and flow control devices must be installed downstream from pumps, compressors, and pressure vessels to prevent the discharge of fluids at—

(a) A rate which would overpressure any downstream component; and

(b) A temperature which would damage any downstream component.

§ 193.915 Pump and compressor control.

(a) Each pump and compressor for flammable fluids must be equipped with—

(1) A control system, operable locally and remotely, to shut down the pump or compressor in a controllable emergency;

(2) A signal light at the pump or compressor and the remote control location which indicates whether the pump or compressor is in operation or idle; and

(3) Adequate valving to insure that the pump or compressor can be isolated for maintenance, including where pumps or compressors operate in parallel, a check valve on each discharge line.

§ 193.917 Control valves.

(a) Each operator shall determine the appropriate locations for, and install, control valves as necessary to—

(1) Protect downstream components from pressures and temperatures which are outside design limits;

(2) Prevent the backflow of fluids in components during normal operation and during malfunction or failure of the component, if such backflow could cause an emergency; and

(3) Shut off the flow of fluids in components in a controllable emergency.

(b) Each valve or combination of valves must—

(1) Have a failsafe design;

(2) Operate to stop fluid flow which would endanger the operational integrity of plant equipment; and

(3) Close at a rate to avoid fluid hammer which would endanger the operational integrity of a component.

§ 193.919 Shutdown control systems.

(a) So far as practicable, shutdown control systems must operate automatically. A reasonable delay may be programmed between warning and automated shutdown to provide for manual response, but a shutdown control system must not rely only on human initiation of the system.

(b) In the case of an LNG facility where components other than a control center are designed to operate unattended, a shutdown control system must be provided at the site of the components and at the control center to safely shut down all operations in an emergency.

§ 193.921 Control center.

Each LNG facility must have a control center from which operations and warning devices are monitored as required by §§ 193.1107 and 193.911. A control center must have the following capabilities and characteristics—

(a) It must be located apart or protected from other components so that it will not be made unusable during a controllable emergency;

(b) Control rooms must be ventilated and constructed so that personnel can use them during any controllable emergency;

(c) All remote control systems must be operable from the control center.

(d) Each control center must have personnel in continuous attendance while the LNG facility is in operation.

§ 193.923 Auxiliary controls.

(a) Each isolation and shutoff valve that is operable from the control center must have auxiliary control devices, including—

(1) One control device located in the immediate vicinity of each valve; and

(2) One control device located so that operating personnel can operate the valve even though a hazard has made the control center and the valve inaccessible.

(b) Each auxiliary control device must be—

(1) Readily accessible under emergency conditions; and

(2) Conspicuously marked with its designated function.

§ 193.925 Failsafe control.

Control systems for liquefaction equipment, storage tanks, and gasification equipment must be designed so that in the event of an electrical power failure or instrument failure, the system will go into a failsafe condition that is maintained until personnel take appropriate action either to reactivate the component served or to prevent a hazard from occurring.

§ 193.927 Sources of electrical power.

Electrical control systems, means of communication, lighting, and fire fighting systems must have two separate and redundant sources of electrical power which function so that the failure of one source does not affect the capability of the other source.

Subpart K—Construction

§ 193.1001 Scope.

This subpart prescribes requirements for the construction and installation of a new LNG facility or an existing facility which is replaced, relocated, or otherwise changed.

§ 193.1003 General.

Components must be constructed or installed to comply with the applicable design requirements of this part using construction personnel and inspectors who are qualified by training and experience in the various phases of construction to which they are assigned.

§ 193.1005 Construction procedures.

(a) Subject to the requirements of § 193.1017, each operator shall prepare and follow written procedures for construction or installation, as the case may be, of each component. The procedures must take into account the chemical composition of the components, the environment to which the components will be exposed, and the function which the finished product will perform. The procedures for joining components designed to contain any flammable or pressurized fluid must be tested to produce a joint which complies with the design and installation requirements of this part applicable to the finished product.

(b) Each test and inspection required by this subpart must be performed in accordance with a written procedure.

§ 193.1007 Identification of critical processes.

Each operator shall determine which construction and installation processes are critical to the structural integrity and safety of components.

§ 193.1009 Qualification of construction personnel.

Subject to the requirements of § 193.1017, for performing each process identified as critical under § 193.1007 and initial testing required by this subpart, each operator shall utilize only those personnel who have demonstrated their capability to satisfactorily perform the function by—

(a) Appropriate training in the methods and equipment to be used or related experience and prior accomplishments; and

(b) Performance on any generally accepted qualification test given by the operator.

§ 193.1011 Construction inspection.

(a) In addition to the initial inspection requirements of this subpart, all construction and installation activities must be inspected as frequently as necessary to—

(1) Assure that the construction and installation of components is in compliance with all applicable requirements of this subpart;

(2) Verify compliance with the applicable material, design, fabrication, installation, and initial testing provisions of this part; and

(3) Assure that the performance of personnel involved in processes identified as critical under § 193.1007 and initial testing required by this subpart is satisfactory.

(b) In addition to the requirements of paragraph (a) of this section, the construction of concrete storage tanks must be inspected in accordance with ACI-311-75.

§ 193.1013 Qualification of inspectors.

(a) In performing inspections required by § 193.1011 and initial inspections required by this subpart, each operator shall utilize only those personnel who have demonstrated their capability to satisfactorily inspect by—

(1) Experience in inspecting or performing the function to be inspected; and

(2) Performance on a generally accepted qualification test given by the operator.

(b) Each operator shall periodically determine whether inspectors are satisfactorily performing their assigned inspections.

§ 193.1015 Cleanup.

Each operator shall clean each component of plant equipment after construction or installation to remove all detrimental contaminants which could cause a hazard during plant startup or operation.

§ 193.1017 Pipe welding.

(a) Each operator shall provide the following for welding on pressurized piping for LNG and other flammable fluids:

(1) Welding procedures and welders qualified in accordance with Section IX of the ASME Boiler and Pressure Vessel Code;

(2) When welding materials which must be impact tested, welding procedures selected to minimize degradation of low temperature properties of the pipe material; and

(3) When welding attachments to pipe, procedures and techniques selected to minimize the danger of burn throughs and stress intensification.

(b) Oxygen fuel gas welding is not permitted on flammable fluid piping with a service temperature below −20°F (−28.9°C).

(c) Marking materials for identifying welds on pipe must be compatible with the basic pipe material.

(d) Surfaces of components that are subject to stress from internal pressure may not be field die stamped.

(e) Where die stamping is permitted, any identification marks must be made with a die having blunt edges to minimize stress concentration.

§ 193.1019 Piping connections.

(a) Piping connections must be welded, except where necessary for material transitions, instrument connections, and maintenance.

(b) Compression type couplings larger than ½ inch nominal pipe size may not be used for service temperatures below −20°F (−28.9°C).

§ 193.1021 Testing acceptance.

No person may place in service any component until it passes all inspections and tests prescribed by this subpart.

§ 193.1023 Testing, general.

(a) Each operator is responsible for testing and inspecting each component in accordance with this subpart to determine if it meets the applicable design, installation, and construction requirements of this part before placing it in operation.

(b) In establishing the test and testing procedure for each component, each operator shall take into account the potential hazard which would result from a failure of the component being tested. So far as practicable, tests must simulate operational conditions.

(c) After tests required by this subpart are completed, if welding is performed on a component to contain LNG or flammable fluid, the component must be retested.

§ 193.1025 Strength tests.

(a) A strength test must be performed on each component to determine whether the component is capable of performing the design function, taking into account—

(1) The design maximum pressure;

(2) The maximum weight of product which the component may contain or support; and

(3) The weight of ice and snow which may reasonably accumulate on the component resulting from weather and from conduction of cold from LNG or refrigerants.

(b) For piping, the test required by paragraph (a) of this section must include a pressure test conducted in accordance with Section 337 of ANSI B31.3, except that test pressures must be based on the design maximum pressure. Carbon and low alloy steel piping must not be pressure tested at metal temperatures below 35°F (1.5°C).

(c) All shells and internals of heat exchangers to which Section VIII, Division 1 or Division 2 of the ASME Boiler and Pressure Vessel Code applies must be pressure tested, inspected, and stamped in accordance therewith.

§ 193.1027 Nondestructive tests.

(a) The following welded pipe joints for LNG and flammable refrigerant service must be nondestructively tested as prescribed to indicate any defects which could adversely affect the integrity of the weld or pipe:

(1) 100 percent of all field welded and all shop welded circumferential buttwelds must be fully examined by radiographic or ultrasonic inspection;

(2) 100 percent of all field socket welds and fillet welds and all shop socket welds and fillet welds must be fully examined by liquid penetrant or magnetic particle inspection; and

(3) Where longitudinally welded pipe is used in transfer systems, 100 percent of the seam weld must be examined by radiographic or ultrasonic inspection.

(b) Load bearing metal shells of storage tanks must be radiographically tested in accordance with Section Q.7.6, API 620, Appendix Q, except that for shells of vertical cylindrical storage tanks and horizontal cylindrical, spherical, toruspherical, ellipsoidal, or other surfaces of compound curvature, 100 percent of both longitudinal and meridional welds must be radiographically tested.

§ 193.1029 Leak tests.

(a) Each component must be initially tested to assure that the component will contain the product for which it is designed without leakage.

(b) Containers must be leak tested by a method appropriate to the design, construction, and maximum allowable operating pressure of the container.

(c) Shop fabricated containers and all flammable fluid piping must be leak tested to a minimum of the anticipated design maximum pressure after installation but before placing it in service.

(d) For a storage tank with vacuum insulation, the inner container, outer shell, and all internal piping must be tested for vacuum leaks in accordance with an appropriate procedure.

§ 193.1031 Testing control systems.

Each control system must be tested before being placed in service to assure that it has been installed properly and will function as required by this par.

§ 193.1033 Storage tank tests.

In addition to other applicable requirements of this subpart, metal and concrete low pressure LNG and flammable liquid storage tanks must be tested in accordance with Section Q.8 and Q.9 of API 620, Appendix Q, as applicable, except that—

(a) For the hydrostatic test, each tank must be filled with water to its maximum liquid level, and reduction of this water level in accordance with Section Q.9.1 is prohibited;

(b) For the pneumatic test, a pressure equal to 1.5 times the design maximum pressure must be applied to the gas space in the tank;

(c) The hydrostatic and pneumatic pressure tests must be maintained for a period of 36 hours after thermal stabilization;

(d) For a concrete shell, all surfaces not sealed by impervious sheeting must be tested to assure there is no leakage;

(e) For both metal and concrete tanks, a standup pressure test must be performed using multiple high precision tank pressure and temperature recorders and two precision atmospheric pressure recorders to assure that the tank is gas tight;

(f) The water test may not cause the total load on the foundation to exceed 100 percent of the design loading; and

(g) Reference measurements must be made with appropriate precise instruments to assure that lateral and vertical movement of the storage tank does not exceed predetermined design tolerances.

§ 193.1035 Inspection of materials.

Each operator shall inspect component materials to verify that they comply with the design specifications and are free of detrimental defects. The scope of the inspection must be commensurate with the hazard which would result from a failure of the component.

§ 193.1037 Construction records.

For the service life of the component concerned, each operator shall retain appropriate records of the following:

(a) Plans, specifications, and procedures for construction or installation;

(b) Each test given construction personnel and inspectors;

(c) Each inspection under § 193.1011; and

(d) Procedures for and results of tests and inspections required by this subpart.

Subpart L—Operations

§ 193.1101 Scope.

This subpart prescribes requirements for the operation of new and existing LNG facilities.

§ 193.1103 General.

(a) To operate an LNG facility, each operator shall utilize only those personnel who have demonstrated their capability to perform their assigned functions by—

(1) Appropriate training and related experience; and

(2) Performance on any generally accepted qualification test given by the operator.

(b) An operator may not permit any person to operate a component unless that person has successfully completed the training required by § 193.1115.

§ 193.1105 Operating procedures.

(a) Each operator shall prepare and follow written procedures for—

(1) Operating components;

(2) Periodically inspecting or testing components which are not continuously monitored to determine if they function in accordance with their operational or safety purposes;

(3) Responding to and correcting malfunctions of components, including taking action if—

(i) Pressure or temperature is outside operating limits; and

(ii) A component malfunctions because of contaminants;

(4) Purging and inerting components, including procedures to—

(i) Verify that the component has been adequately purged before introducing air or flammable fluids; and

(ii) Verify, as applicable, that noncombustible conditions are maintained between the out-of-service purge and the restoration of normal operation; and

(5) Cooldown of applicable components, including verifying that any cooldown fluid, if other than the system design fluid, is compatible with the materials of the component being cooled.

§ 193.1107 Monitoring operations.

Each operator shall continuously monitor those aspects of operations which significantly affect the integrity or safety of the LNG facility, including pressure and temperature, as applicable.

§ 193.1109 Emergency procedures.

(a) Each operator shall determine what controllable emergencies may reasonably be expected to occur at an LNG facility.

(b) Each operator shall prepare and follow written procedures for—

(1) Responding to controllable emergencies; and

(2) Recognizing an uncontrollable emergency and taking the necessary actions for public safety and the safety of personnel.

§ 193.1111 Personnel safety.

(a) Each operator shall determine the potential hazards to personnel involved in operating and maintenance activities and provide suitable protective clothing and equipment necessary for the safety of personnel while they are conducting their duties.

(b) Each LNG facility must have a shelter to provide protection for all personnel against thermal radiation from a burning pool of impounded liquid. The shelter must have a water supply adequate for the immersion of burned personnel.

§ 193.1113 Personnel participation.

Each operator shall develop and follow a program to verify that the personnel assigned to the operation of critical components and processes are mentally and physically able to carry out their assigned functions.

§ 193.1115 Training.

Each operator shall provide:

(a) An initial training program for operating and maintenance personnel to instruct them:

(1) About the characteristics and hazards of LNG and other flammable fluids used at the facility, including low temperatures, flammability of mixtures with air, odorless vapor, boiloff characteristics, and reaction to water and water spray;

(2) For operating personnel, in the appropriate aspects of operating plant equipment and to carry out the operating procedures under § 193.1105; and

(3) To carry out the emergency procedures under § 193.1109.

(b) A continuing training program to keep operating and maintenance personnel current on the knowledge and skills they gained in the initial training.

§ 193.1117 Transfer procedures.

(a) Each operator shall prepare and follow written procedures for the transfer of LNG and other flammable fluids between all credible combinations of process areas, impoundment systems, sump basins, storage tanks, containers, tank cars, tank trucks, marine vessels, and pipelines as are likely to occur at the LNG facility.

(b) The transfer procedures must provide for at least one person to be in constant attendance during all transfer operations.

(c) The transfer procedures must include provisions for personnel to:

(1) Verify that transfer systems have been adequately purged, if appropriate, and are ready for transfer operations with connections and controls in proper positions;

(2) Verify that the receiving vessels comply with the applicable codes and regulations for the intended use and that all transfer hoses have been visually inspected for damage or defects;

(3) Verify that the receiving vessels do not contain any substance that would be incompatible with the incoming fluid and that there is sufficient capacity available to receive the amount of fluid to be transferred;

(4) Verify the maximum filling volume of any vessel to ensure that expansion of the liquid due to warming will not result in over filling or over pressurization;

(5) Precool or cooldown transfer lines and associated equipment where applicable at a rate and distribution pattern that will not cause excess thermal stresses or damaging forces on the system, paying particular attention to expansion and contraction devices to determine that they are performing properly;

(6) Verify the acceptable flow rates and control the flow rates to prevent overpressure or overfilling with sufficient monitoring of applicable flow rates, liquid levels, vapor returns, pressures and other significant data to verify that the transfer operations are proceeding within design conditions;

(7) Determine any differences in temperature or specific gravity between the fluid being transferred to a vessel and the fluid already in the vessel when making bulk transfer and if applicable provide means to prevent stratification;

(8) Manually terminate the flow before overfilling occurs; and

(9) Deactivate cargo transfer systems in a safe manner by depressurizing, venting, and disconnecting lines and other appropriate operations.

(d) In addition to the requirements of paragraph (c) of this section, the procedures for transfer of liquids into and from tank cars and tank trucks must include provisions for personnel to:

(1) Verify that tank trucks are positioned so that they need not exit the transfer area by backing;

(2) Prohibit the backing of a tank truck in the transfer area, except when a person is positioned at the rear of the tank truck giving instructions to the driver;

(3) Verify that the vehicle engine is shut off prior to transfer operations, unless it is required for the transfer operations, and that it is not restarted until the transfer lines have been disconnected and any release vapors have dissipated;

(4) Prevent loading LNG into a tank car or tank truck which is not in exclusive LNG service, or if in exclusive service, which does not contain a positive pressure, until after the oxygen content in the container is tested and purged if it exceeds 2 percent by volume;

(5) Before connecting a transfer line and beginning the flow of liquid, verify that a tank car or tank truck has been immobilized, secured, and electrically grounded, and for tank cars and tank vehicles which are top loaded through an open dome, electrically bonded to the fill piping or grounded prior to opening the dome in accordance with Section 550 of NFPA-77;

(6) Verify that all transfer lines have been disconnected and equipment cleared before the vehicle is moved from the transfer position; and

(7) Verify that transfers into pipeline systems will not exceed the pressure or temperature limits of the system.

(e) An operator may not begin a marine transfer until:

(1) The officer-in-charge of the vessel and the person-in-charge of the shore terminal have:

(i) Inspected their respective facilities to ensure that transfer equipment is compatible and in proper operating condition;

(ii) Met and approved the transfer procedure;

(iii) Verified that adequate ship-to-shore communications exist; and

(iv) Reviewed emergency procedures; and

(2) The operator determines that the loading and unloading of general cargo and bunkering will be performed under strict supervision to prevent develop-

ment of potential hazards when transfer operations are in progress.

§ 193.1119 Protecting transfer operations.

During cargo transfer operations, personnel and warning signs or barricades must be used to:

(a) Protect the transfer area from sources of ignition, including sparking tools, static electricity, smoking, and open flames; and

(b) Prohibit vehicle traffic near transfer lines and manifolds.

§ 193.1121 Investigation of failures.

(a) Each operator shall investigate and determine the cause of each malfunction of a component which results, or could have resulted, in:

(1) Death or personal injury requiring hospitalization; or

(2) A threat to the operational integrity or safety of the LNG facility.

(b) Each operator shall take appropriate corrective action as a result of such investigations and except for a malfunction reported in a leak report under Part 191 of this chapter, report the incident to the Secretary within 30 days.

§ 193.1123 Security; procedures and personnel.

(a) Each operator shall prepare and follow written procedures to provide security for each LNG facility. The procedures must include, at least:

(1) A plan and description of the facility depicting the function and characteristics of all critical components.

(2) Normal operating temperatures and pressure ranges of critical components.

(3) Characteristics of potential hazards involving a critical component caused by malfunctions or damage.

(4) Personnel duties, stating the nature and frequency, as applicable, or security checks and inspections.

(5) Instructions for actions to be taken, including notification of other facility personnel and public officials, in the event of a:

(i) Potential and actual operational irregularity;

(ii) Potential and actual breach of security; and

(iii) Potential and actual emergency.

(6) Liaison with appropriate public officials, including police and fire officials, notifying them of the plans and procedures for security.

(7) Alternative means of notifying police and fire officials when a breach of security occurs.

(b) Personnel responsible for maintaining security at an LNG facility must be:

(1) Appropriately trained to carry out the security procedures under paragraph (a) of this section.

(2) Physically capable, and properly equipped to perform all functions of their assigned duties; and

(3) Familiar with plant functions and emergency procedures.

§ 193.1125 Security; enclosures required.

(a) Except as provided in paragraph (c) of this section, an LNG facility must be surrounded by a protective enclosure which is designed, operated, and maintained in accordance with this subpart to prevent unauthorized access to the facility.

(b) The enclosure must be located a sufficient distance from each of the following critical components to minimize the opportunity for sabotage, or intentional damage to a component, but not less than the minimum distance from the critical component to the site boundary prescribed by § 193.123:

(1) Storage tank;
(2) Processing equipment,
(3) Gasifier,
(4) Transfer piping;
(5) Cargo transfer system;
(6) Control systems and center,
(7) Fire protection equipment,
(8) Hazardous materials storage area.

(c) Paragraph (a) of this section does not apply to: (1) A component which is:

(i) Outside the general plant area; and

(ii) Protected by a separate enclosure in accordance with this subpart; and

(2) A component which:

(i) Is located within a building used primarily for purposes other than housing the component; and

(ii) Is either: (A) Continuously monitored by operating personnel who maintain communications with personnel at other locations in a manner designed to provide a warning of potential danger to the component; or

(B) Protected against unauthorized access by locked entries.

§ 193.1127 Security; enclosure design.

(a) A protective enclosure must have sufficient strength and be constructed and maintained in a manner to protect against unauthorized entry.

(b) Ground elevation outside an enclosure must be graded in a manner that will not impair the effectiveness of the enclosure.

(c) Culverts, gullys, or depressions necessary for drainage under an enclosure must be blocked by fixed grating or grills capable of providing security equal to that of the enclosure.

(d) An enclosure may not be located near topographical features, such as trees, poles, or buildings, which could be used to breach the security afforded by the enclosure.

§ 193.1129 Security; enclosure accesses.

(a) At least two accesses, located so that escape routes will be the safest for personnel in the event of an emergency, must be provided in enclosures having a perimeter length up to 200 feet. One additional access located for maximum safety of escape must be provided for each additional 200 feet of enclosure length, except that an access need not be provided where it only would reduce the distance for escape by less than 10 percent or change the direction for escape by less than 22.5°.

(b) When an LGN facility is in operation, each enclosure access must be locked except when guarded, during passage of authorized personnel, and in an emergency. During normal operations, an enclosure access may be unlocked only by persons designated by the operator to maintain the security of the enclosure. During an emergency, a means must be available to each person within the enclosure to unlock each enclosure access.

(c) Where enclosure accesses are guarded:

(1) A guard must be in continuous attendance to prevent unauthorized access to the facility; and

(2) A means must be provided for direct communication between the access guard and personnel at other locations.

§ 193.1131 Security; lighting.

In addition to lighting required for operation, each LNG facility must be sufficiently lighted to provide for inspecing the condition of each critical component and to monitor the facility area for trespass.

§ 193.1133 Security; monitoring.

(a) Each LNG facility must be continuously monitored within the enclosure for the presence of unauthorized personnel and malfunctioning critical components.

(b) Where critical components and the facility area are not monitored by direct visual observation, closed circuit television with directionally controllable cameras must be used.

(c) In addition to the requirement of paragraph (b) of this section, each LNG facility with a storage capacity of 250,000 barrels, or more, of LNG, must be monitored with security warning systems which operate based on circuit continuity, induction fields, photoelectrics, proximity sensors, or similar detection principles.

§ 193.1135 Security; warning signs.

(a) Where the boundary of the exclusion zone of an LNG facility is located outside the protective enclosure, warning signs must be placed along the boundary so that anyone approaching the site will have a clear indication of:

(1) The presence of an LNG facility;

(2) The location of the exclusion zone boundary; and

(3) Potential hazards associated with the exclusion zone.

(b) Warning signs must be conspicuously placed along each protective enclosure, at intervals so that at least one sign is recognizable during daylight from a distance of 100 feet from any point of approach to the enclosure. Signs must be marked with the following on a background of sharply contrasting color:

(1) The words "Warning," "Liquefied Natural Gas Facility," and "Do Not Trespass," or words of comparable meaning.

(2) The name of the operator and the telephone number where the operator can be reached at all times.

§ 193.1137 Maximum allowable operating pressure.

(a) Each operator shall determine the maximum and minimum allowable operating pressure of components containing hazardous fluids.

(b) A component may not operate outside the limits of its maximum and minimum allowable operating pressures during normal operation.

§ 193.1139 Purging.

(a) Components that could accumulate significant amounts of combustible mixtures must be purged in a safe manner after being taken out of service and before being returned to service.

(b) During purging operations, a component must be checked to assure that a combustible mixture is not produced.

§ 193.1141 Operating records.

Each operator shall maintain daily records to describe the actual performance of critical components.

Subpart M—Maintenance

§ 193.1201 Scope.

This subpart prescribes requirements for maintaining new and existing LNG facilities.

§ 193.1203 General.

(a) Each component must be maintained in a condition that—(1) Is compatible with its operational or safety purpose; and (2) Provides protection against contaminants, deterioration, and misalignment with other components that would impair its operational or safety purpose.

(b) Each operator shall repair, replace, or remove any component which does not meet its operational or safety purpose.

(c) When repairs are made while a component is operating, each operator shall take appropriate precautions to maintain the safety of the facility and personnel during repair activities.

(d) To the greatest extent practicable, repair work must comply with the applicable construction requirements of Subpart K of this part.

§ 193.1205 Maintenance procedures.

(a) Subject to other applicable requirements of this subpart, each operator shall determine and perform consistent with generally accepted engineering practices, the periodic inspections or tests needed to verify that components meet the maintenance standards prescribed by this subpart. A periodic inspection or test must establish the following, as applicable:

(1) Whether a component is compatible with its operational or safety purpose;

(2) Whether a component is being subjected to blockage by foreign material, contaminants, or ice;

(3) Whether each control system is properly adjusted;

(4) Whether any foundation, whose failure could reasonably be expected to cause a significant hazard, has experienced a detrimental change; and

(5) Whether a power source is sufficient to supply all connected equipment, taking into account simultaneous operations and startup.

(b) Each operator shall prepare and follow written maintenance procedures which prescribe the details of the inspections or tests determined under paragraph (a) of this section and their frequency of performance.

§ 193.1207 Maintenance of fire fighting equipment.

All fire fighting equipment must be inspected and maintained in accordance with the manufacturers recommendations and Chapter 5 of NFPA Standard 10.

§ 193.1209 Isolating and purging.

Components which are isolated for maintenance must be purged of hazardous fluids before personnel begin maintenance activities. If the component or maintenance activity provides an ignition source, a method, in addition to an isolation valve, must be used to prevent leakage of a hazardous fluid into the component.

§ 193.1211 Testing repairs.

So far as practicable, each operator shall test repaired components according to the requirements of Subpart K of this part under which the component was initially tested.

§ 193.1213 Contaminants.

(a) Each operator shall determine—(1) The components of plant equipment in which contaminants may accumulate to impair the operational or safety purpose of the component; (2) The types of contaminants which may accumulate in each component; and (3) The effect on components of the accumulation of contaminants.

(b) Each operator shall periodically inspect or test for contaminants in components identified under paragraph (a) of this section and remove any accumulation of contaminants which could impair the operational or safety purpose of the components.

§ 193.1215 Testing control systems.

After an initial test under § 193.1031, each control system must be subsequently inspected and tested as frequently as needed to verify that each system stays within design requirements, but at intervals not exceeding 12 months and before returning to service after a shutdown of one month or more.

§ 193.1217 Testing transfer hoses.

Hoses used in LNG or flammable refrigerant transfer systems must be tested at intervals not exceeding 12 months to the maximum pump pressure or relief valve setting and must be visually inspected for damage or defects before each use.

§ 193.1219 Inspecting storage tanks.

Each new storage tank in operation must be inspected using appropriate instruments, as prescribed, to assure that each of the following conditions is not a potential hazard to the structural integrity or safety of the tank:

Condition	*Inspection*
(1) Vertical and lateral movement, distortion, and other dislocation of the foundation, tank structure, and transfer lines.	At 3-month intervals for first 3 years of service, thereafter at 12-month intervals, and within a week after a major meteorological or geophysical disturbance, using reference monuments and theodolites.
(2) Stratification of cryogenic liquids.	Before and after each addition of LNG to tank but at least at 3-month intervals, using (1) sample lines at vertical intervals not more than 10 percent of design height of liquid, and (2) appropriate analyzers.
(3) Thermal gradients in tank structure.	At 3-month intervals and when cold spots are evident, using thermocouples, infrared scanners, or similar devices.

§ 193.1221 Maintenance records.

Each operator shall keep a record of the date and type of each maintenance activity performed on each component as required by this subpart, including periodic tests and inspections, for 5 years after the activity.

Subpart N—Fire Prevention

§ 193.1301 Scope.

This subpart prescribes requirements for design and performance of fire prevention and fire protection equipment, systems, and methods for new and existing LNG facilities.

§ 193.1303 General.

Each operator shall provide fire protection equipment, systems, and methods to comply with this subpart. To the extent practicable, an LNG facility must be operated and maintained in a manner that will minimize—

(a) The potential for the accidental release of flammable liquids or gases;

(b) The incidence of fires; and

(c) The consequences of a fire should it occur.

§ 193.1305 Fire prevention plan.

(a) Each operator shall determine—

(1) In consultation with local fire department officials, the potential causes of fires which could affect each LNG facility; and

(2) Those areas of an LNG facility where the potential exists for the presence of flammable liquids or gases in accordance with Section 500-4 of NFPA-70.

(b) Each operator shall prepare and follow written fire prevention procedures to—

(1) Post areas determined under paragraph (a) (2) of this section with warning signs;

(2) Reduce to a minimum the leakage or release of flammable liquids or gases;

(3) Prohibit smoking, open fires, and other similar ignition sources except in designated and properly posted area;

(4) Prohibit welding, cutting, and similar operations except at times and places specifically authorized and constantly supervised in accordance with Section 4 of NFPA-51B;

(5) Prohibit the storage of flammable or combustible materials in areas with ignition sources;

(6) Purge piping or a container of a combustible mixture when it is being placed into, returned to, or taken out of service; and

(7) Prohibit vehicles and other mobile equipment which constitute potential ignition sources in the area of process equipment containing LNG, flammable liquids, or flammable refrigerants except when specifically authorized and under constant supervision.

§ 193.1307 Fire fighting plan.

(a) Each operator shall determine the types of potential fires within the LNG facility, the predictable consequences of these fires, and the potential subsequent failures which could add to the consequences of these fires.

(b) Each operator shall prepare and follow detailed procedures to cover potential fire emergencies with emphasis on cutting off the flows of potential fuels, isolation of equipment and containers of fuels, depressuring endangered pressurized equipment, and other applicable steps to cut off or reduce the escape of gas or liquid.

(c) Each operator shall provide five flighting protection for components whose failure due to fire exposure could cause an emergency. The protection must be located near the places determined under paragraph (a) of this section and include at least the following.

(1) Portable or wheeled fire extinguishers suitable for gas fires, preferably of the dry chemical type, which meet the requirements of Chapter 4 of NFPA-10; and

(2) If the total inventory of LNG and flammable refrigerants is more than 2,000 barrels, water supply and associated equipment, adequate for the purpose of protecting cooling equipment and piping, and controlling unignited leaks and spills.

(d) The design of the water supply system and the method of water distribution for fire protection must be determined by the fire exposure, both within and external to the facility, and in accordance with good fire protection practices for LNG facilities.

(e) Each operator shall provide LNG facility personnel suitable protective clothing and equipment for use in fire fighting operations. Self-contained breathing apparatus must be available if appropriate.

(f) All emergency controls and fire fighting equipment must be conspicuously located and marked for easy recognition and accessibility. Any special or precautionary instructions for their use must be placed at the equipment location.

(g) Each operator shall provide portable flammable gas indicators and make them readily availble for use by the LNG facility personnel within process areas.

§ 193.1309 Coordination with public safety agencies.

Each operator shall cooperate with local fire departments, law enforcement agencies, and civil defense agencies in fire fighting and handling other emergencies at the LNG facility. Such cooperation must include familiarization with the LNG facilities, familiarization with potential hazards at the facility, including potential causes and areas of fires determined under § 193.1305(a) and determinations under § 193.1307(a), coordination of respective fire fighting efforts, direct communications, and public protection and control.

§ 193.1311 Training.

Each operator shall establish, implement, and maintain a program of instruction necessary to have all LNG facility personnel appropriately trained to—

(a) Know and obey the fire safety rules and plans of this subpart that relate to their assignments;

(b) Recognize potential causes and areas of fires determined under § 193.1305(a), predictable consequences and failures determined under § 193.1307 (a), and breaches of security affecting both the facilty and personnel; and

(c) Know and be able to perform their assigned duties according to the established procedures for fire fighting.

§ 193.1313 Records.

(a) Each operator shall establish a system of records which—

(1) Provides evidence that the training programs required by § 193.1311 have been implemented and maintained; and

(2) Provides evidence that personnel who have undergone the required training programs have satisfactorily attained the proficiency goals of such programs.

(b) Records must be maintained until 3 years after personnel are not assigned duties at the facility.

Subpart O—Corrosion Control

§ 193.1401 Scope.

This subpart prescribes requirements for the protection of new and existing LNG facilities from external, internal, and atmospheric corrosion to provide for the integrity and reliability of facilities over their service life.

§ 193.1403 General.

Each operator shall prepare and follow corrosion control procedures to meet the requirements of this subpart. These procedures, including those for the design, installation, operation, and maintenance of cathodic protection systems, must be carried out by, or under the direction of, a person qualified by experience and training in corrosion control methods.

§ 193.1405 Corrosion control overview.

An LNG facility may not be constructed, replaced, or repaired until a person described in § 193.1403 reviews the applicable design drawings and material specifications to assure that the materials involved will not imperil the safety or reliability of the facility from a corrosion control viewpoint.

§ 193.1407 Atmospheric corrosion control.

Except for materials specifically designed to prevent atmospheric corrosion, each component whose integrity or reliability could be adversely affected by atmospheric corrosion must be protected by a suitable coating or jacketing material.

§ 193.1409 External corrosion control: buried or submerged components.

(a) Except for components that are protected from external corrosion specifically by material design and selection, each metal component, including any metal reinforcing material, that is in direct contact with soil, water, concrete, sand, or gravel must be protected from detrimental corrosion that may impair its operational integrity or reliability. The protection must include in the contacted area—

(1) An external protective coating designed and installed to prevent corrosion attack and to meet the requirements of § 192.461 of this Chapter; and

(2) Except for reinforcing material located above ground in concrete, a supplemental cathodic protection system designed to protect the component in its entirety in accordance with Appendix D to Part 192 of this Chapter, placed in operation immediately after installation.

(b) Where cathodic protection is applied, components that are electrically interconnected must be protected as a single unit.

§ 193.1411 Internal corrosion.

Each operator shall determine which components are subject to internal corrosive attack, and take appropriate steps to protect the components against failure due to internal corrosion.

§ 193.1413 Environmentally induced cracking.

To the extent practical under available technology, each component must be protected from failure resulting from, or a combination of, corrosion fatigue, stress corrosion cracking, hydrogen embrittlement, and hydrogen stress cracking.

§ 193.1415 Interference currents.

(a) Each LNG facility that is subject to electrical current interference must have in effect a continuing program to minimize the detrimental effects of currents.

(b) Each cathodic protection system must be designed and installed so as to minimize any adverse effects it might cause to adjacent metallic components.

(c) Each impressed power source must be filtered at input and output circuits to prevent unintended interference with control networks.

§ 193.1417 Contaminants.

Each component must be cleaned of contaminants before being placed in operation or returned to operation, including the following:

(a) The operator shall determine the effect of each contaminant or combination thereof on the mechanical behavior of the material.

(b) All flux residues used in brazing or soldering must be removed from the joints and the base metal to prevent corrosive solutions from being formed.

(c) All solvent type cleaners must be tested to ensure that they will not damage equipment integrity or reliability.

(d) Alloy welded joints must be protected against weld decay and carbide precipitation in the heat affected zone.

(e) Incompatible chemicals must be removed.

(f) All contaminants must be captured and disposed of in a manner that does not reduce the effectiveness of corrosion protection and monitoring provided as required by this subpart.

§ 193.1419 Monitoring corrosion control.

Corrosion protection provided as required by this subpart or provided by material design and selection must be monitored for early recognition of ineffective corrosion protection, including the following, as applicable:

(a) Each critical bond installed to correct electrical current interference problems must be tested at intervals not exceeding 2 months to assure that it is performing its function.

(b) Each critical reverse current switch or diode installed to correct electrical current interference problems must be tested at intervals not exceeding 2 months to assure that it is performing its function.

(c) External and atmospheric corrosion protection must be evaluated at intervals not exceeding 6 months to determine its adequacy.

(d) Internal corrosion protection must be monitored at intervals not exceeding 4 months to determine its adequacy.

(e) Each device used to determine the adequacy of internal corrosion protection, such as coupons or probes, must be located where corrosion occurs, not midstream or flow center.

(f) Each component must be monitored periodically to determine the adequacy of protection provided against environmentally induced cracking under § 193.1413.

(g) Except for a failure reported in a leak report under Part 191 of this chapter, each component failure caused by corrosion which occurs before the end of the component's service life must be reported to the Secretary within 30 days after the failure.

(h) Each cleaning solution used to wash components must be checked for contaminants that can increase corrosion rates.

(i) Corrosion rate data must be obtained annually for external, internal, and atmospheric corrosion attack and used to adjust protection systems as necessary.

§ 193.1421 Remedial measures.

Prompt corrective or remedial action must be taken whenever an operator learns by inspection or otherwise that atmospheric, external, or internal corrosion or environmentally induced cracking is not controlled as required by this subpart.

§ 193.1423 Corrosion control records.

(a) Each operator shall maintain records or maps to show the location of cathodically protected components, neighboring structures bonded to the cathodic protection system, and corrosion protection equipment.

(b) Each of the following records must be retained for as long as the LNG facility remains in service:

(1) Each record or map required by paragraph (a) of this section.

(2) Records of each test, survey, or inspection required by this subpart, in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist.

APPENDIX A

I. LIST OF ORGANIZATION AND ADDRESSS

A. American Concrete Institute (ACI), P.O. Box 19150, Redford Station, Detroit, Michigan 48219.

B. American Gas Association (AGA), 1515 Wilson Boulevard, Arlington, Virginia 22209.

C. American National Standards Institute (ANSI), 1430 Broadway, New York, New York 10018.

D. American Petroleum Institute (API), 1801 K Street, NW., Washington, D.C. 20006.

E. American Society of Mechanical Engineers (ASME), United Engineering Center, 345 East 47th Street, New York, New York 10017.

F. International Conference of Building Officials, 5360 South Workman Mill Road, Whittier, California 90601.

G. National Fire Protection Association (NFPA), 470 Atlantic Avenue, Boston, Massachusetts 02210.

II. DOCUMENTS INCORPORATED BY REFERENCE

A. American Concrete Institute (ACI)

1. ACI Standard 311-75 "Recommended Practice for Concrete Inspection," 1975 edition, (ANSI A188.2).

2. ACI Standard 318-71 "Building Code Requirements for Reinforced Concrete," 1971 edition, (ANSI A89.1).

3. ACI Standard 67-40 "Design and Construction of Circular Prestressed Concrete Structures," 1970 edition.

B. American Gas Association (AGA)

1. "American Gas Association Project IS-3-1, LNG Safety Program, Interim Report on Phase II Work," July 1, 1974.

C. American National Standards Institute (ANSI)

1. ANSI B31.3 "Petroleum Refinery Piping," 1973 edition.

D. American Petroleum Institute (API)

1. API Standard 620 "Recommended Rules for Design and Construction of Large, Welded, Low Pressure Storage Tanks," Fifth edition, July 1973, (ANSI B184.1).

E. American Society of Mechanical Engineers (ASME)

1. ASME Boiler and Pressure Vessel Code Section I, Power Boilers, 1974 edition.

2. ASME Boiler and Pressure Vessel Code, Section VIII, Division 1, Pressure Vessels; Division 2, Alternative Rules, Pressure Vessels, 1974 edition.

3. ASME Boiler and Pressure Vessel Code, Section IX, Welding and Brazing Qualifications, 1974 edition.

F. International Conference of Building Officials

1. Uniform Building Code, 1976 edition.

G. National Fire Protection Association (NFPA)

1. NFPA Standard 10 "Installation, Maintenance and Use of Portable Fire Extinguishers," 1975 edition.

2. NFPA Standard 37 "Stationary Combustion Engines and Gas Turbines," 1975 edition.

3. NFPA Standard 51B "Fire Prevention in Use of Cutting and Welding Processes," 1976 edition.

4. NFPA Standard 70 "National Electrical Code," 1975 edition.

5. NFPA Standard 77 "Recommended Practice on Static Electricity," 1972 edition.

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