BEFORE THE
UNITED STATES DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
WASHINGTON, D.C.

Pipeline Safety: Amendments to Liquefied Natural Gas Facilities	Docket No. PHMSA-2019-0091

COMMENTS IN RESPONSE TO "AMENDMENTS TO LIQUEFIED NATURAL GAS FACILITIES" ADVANCE NOTICE OF PROPOSED RULEMAKING

FILED BY
AMERICAN PETROLEUM INSTITUTE
CENTER FOR LNG
INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA
AMERICAN GAS ASSOCIATION
AMERICAN PUBLIC GAS ASSOCIATION
NORTHEAST GAS ASSOCIATION

July 7, 2025

Table of Contents

I. Introduction

The American Petroleum Institute (API),[1] the Center for LNG (CLNG),[2] the Interstate Natural Gas Association of America (INGAA),[3] American Gas Association (AGA),[4] American Public Gas Association (APGA),[5] and the Northeast Gas Association (NGA),[6] collectively, the Associations, respectfully submit these comments in response to the Pipeline and Hazardous Materials Safety Administration's (PHMSA or the Agency) Advance Notice of Proposed Rulemaking for Liquefied Natural Gas Facilities Amendments (the LNG ANPRM).[7] PHMSA is seeking feedback on potential amendments of its siting, design, installation, construction, inspection, testing, operation, and maintenance requirements for LNG facilities in 49 CFR Part 193.

The Associations support PHMSA's efforts to modernize its Part 193 regulations, a set of requirements that has not been updated in 21 years.[8] As the Agency recognized in the LNG ANPRM,[9] Congress, the U.S. Government Accountability Office (GAO), industry, and other stakeholders have all urged PHMSA to update these regulations to accommodate new technology, best practices, and lessons learned.[10] The Part 193 regulations were first introduced in 1972 as an

---

[1] API is the national trade association representing all facets of the oil and natural gas industry, which supports 10.3 million U.S. jobs and 8 percent of the U.S. economy. API's nearly 600 members include large integrated companies, as well as exploration and production, refining, marketing, pipeline, and marine businesses, and service and supply firms. They provide most of the nation's energy and are backed by a growing grassroots movement of millions of Americans.

[2] CLNG champions public policies that advance the production of LNG in the U.S., increase international exports, and help power a clean energy future. CLNG represents LNG producers, shippers, and multinational developers in the U.S. It also serves as a resource for educational and technical information to help policymakers fully realize the potential of LNG to meet the world's energy needs while reducing emissions and supporting domestic economic growth.

[3] INGAA is comprised of 27 members, representing the vast majority of the U.S. interstate natural gas transmission pipeline companies. INGAA's members operate nearly 200,000 miles of pipelines and serve as an indispensable link between natural gas producers and consumers.

[4] Founded in 1918, AGA represents more than 200 local energy companies committed to the safe and reliable delivery of clean natural gas to more than 180 million Americans. AGA is an advocate for natural gas utility companies and their customers and provides a broad range of programs and services for member natural gas pipelines, marketers, gatherers, international natural gas companies, and industry associates. Today, natural gas meets more than one third of the United States' energy needs.

[5] APGA is the national, non-profit association of publicly owned natural gas distribution systems. APGA was formed in 1961 as a non-profit, non-partisan organization, and currently has over 740 members in 37 states. Overall, there are nearly 1,000 municipally owned systems in the U.S. serving more than five million customers. Publicly owned gas systems are not-for-profit retail distribution entities that are owned by, and accountable to, the citizens they serve. They include municipal gas distribution systems, public utility districts, county districts, and other public agencies that have natural gas distribution facilities.

[6] The NGA is a regional trade association that focuses on education and training, technology research and development, operations, planning, and increasing public awareness of natural gas in the Northeast U.S.

[7] Pipeline Safety: Amendments to Liquefied Natural Gas Facilities, 90 Fed. Reg. 18,949 (May 5, 2025).

[8] PHMSA's last revision of Part 193 occurred in 2004 with a handful of updates to certain standards incorporated by reference in 2015. *See* Pipeline Safety: Periodic Updates of Regulatory References to Technical Standards and Miscellaneous Amendments, 80 Fed. Reg. 168 (Jan. 5, 2015). However, many provisions of Part 193 date back to the 1980s.

[9] Pipeline Safety: Amendments to Liquefied Natural Gas Facilities, 90 Fed. Reg. at 18,950 (referencing section 27 of the PIPES Act of 2016 and section 110 of the PIPES Act of 2020).

[10] *Id.*

interim measure.[11] The Materials Transportation Bureau (MTB), PHMSA's predecessor, then introduced more fulsome regulations in 1980.[12] At the time, the LNG industry looked remarkably different than today's diversity of operations, facilities, and market opportunities. Today's LNG industry has experienced notable growth in both liquefaction capacity and number of export facilities. Updated regulations are sorely needed to accommodate these changes and advances in technology.

The Associations represent a diverse set of members including (1) large-scale/baseload; (2) small-scale/peak shavers; (3) satellite; and (4) mobile or temporary facilities. While the Associations have attempted to present a unified position in response to PHMSA's questions, the Associations distinguish below where their position is unique to one of the four categories of LNG facilities. Given the key operational differences between large-scale/baseload, small-scale/peak shavers, satellite, and mobile or temporary facilities, a broad, "one-size-fits-all" approach is not always a workable solution.

II. Comments

A. Clarifying Regulatory Amendments

1. Regulatory Overlap

Question A.1:

What regulatory amendments could improve or clarify the applicability of PHMSA's Part 193 regulations to LNG facilities under its statutory authority?

Should PHMSA's regulations be amended to clarify the boundaries of its regulatory authority with respect to some or all categories of LNG facilities?

Which provisions (including regulatory definitions) merit revision and how should they be modified?

While the Associations recognize that the Federal Energy Regulatory Commission (FERC), the U.S. Coast Guard (USCG), PHMSA, the Occupational Safety and Health Administration (OSHA), and states all have various roles in regulating the different types of LNG facilities, additional clarity is needed to avoid unnecessary and redundant regulation and inspections. Congress has also raised concerns with the lack of coordination of federal agencies regulating LNG facilities.[13] PHMSA should take a closer look at the overlaps and set clearer boundaries between the agencies. PHMSA and FERC should improve their coordination and agree that PHMSA is best equipped to take the lead role in conducting operations and safety inspections. USCG is the appropriate agency to

[11] "Transportation of Natural and other Gas by Pipeline Minimum Federal Safety Standards: Liquified Natural Gas Systems," 37 Fed. Reg. 21,638 (Oct. 13, 1972).
[12] "Liquefied Natural Gas Facilities; New Federal Safety Standards," 45 Fed. Reg. 9,184 (Feb. 11, 1980).
[13] In H.R. 6494, the U.S. House of Representatives, Committee on Transportation and Infrastructure, proposed that DOT "establish a Liquefied Natural Gas Regulatory Safety Working Group through the National Center of Excellence for Liquefied Natural Gas Safety to clarify the authority of Federal agencies in the authorizing and oversight of LNG facilities (other than peak shaving facilities) and improve coordination of the authority of such agencies."

conduct security inspections of waterfront LNG facilities adjoining the navigable waters of the United States. For decades, PHMSA has entered into Memoranda of Understanding (MOUs) with other federal agencies to avoid duplicative regulatory efforts.[14] PHMSA's predecessors have then codified this division of responsibility as it pertains to Part 193.[15] As discussed below, PHMSA should update its existing MOUs with both FERC and USCG to more accurately reflect divisions of responsibility, then codify these distinctions, and, wherever appropriate, accept compliance with analogous regulations.

a. Security Requirements for Waterfront LNG Facilities Adjoining the Navigable Waters of the United States

PHMSA should establish USCG as the primary agency for security requirements for those waterfront LNG facilities adjoining the navigable waters of the United States and subject to 33 CFR §§ 105 and 127. The Materials Transportation Bureau (MTB), PHMSA's predecessor, took a similar approach in 1978, when it established via MOU that the USCG was the primary agency for inspecting security requirements at a waterfront LNG facility adjoining the navigable waters of the United States.[16] In 1986, the Research and Special Programs Administration (RSPA), another PHMSA predecessor, and the USCG reconsidered this division of responsibilities and entered into a revised MOU.[17] As a result, RSPA later codified security requirements for waterfront LNG facilities in Part 193.[18] At the time, the agencies' reasoning for this change was the assumption that non-waterfront LNG plants are similar in size and operating characteristics to waterfront LNG plants and RSPA's growing experience in applying security standards.[19] As discussed above, the LNG industry has experienced notable growth and change in both liquefaction capacity and number of export facilities in the decades since the 1986 MOU was written. Given the changes in operating characteristics and the number of facilities, PHMSA should re-establish that USCG, not PHMSA, is primarily responsible for regulating the security of waterfront LNG facilities adjoining the navigable waters of the United States. PHMSA should then codify this change by adding an exemption to section 193.2001(b).

---

[14] PHMSA Inter-Agency Memoranda of Understanding, https://www.phmsa.dot.gov/pipeline/liquified-natural-gas/phmsa-inter-agency-memoranda-understanding (last accessed on June 24, 2025).

[15] *See* Liquefied Natural Gas Facilities; New Federal Safety Standards, 45 Fed. Reg. 9,184, 9, 185 (Feb. 11, 1980)("The scope of Part 193 (§ 193.2001) has been written to reflect the MOU's jurisdictional delineations regarding all matters between a vessel and tank, and matters relating to security and fire protection will be covered separately in final rules on those topics").

[16] *See* Memorandum of Understanding Between the United States Coast Guard and the Materials Transportation Bureau for Regulation of Waterfront Liquefied Natural Gas Facilities, https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/1978_MTB_USCG.pdf (Feb. 7, 1978). *See also,* Fire Protection and Security of Waterfront Liquefied Natural Gas Facilities, 52 Fed. Reg. 674 (Jan. 1987)("Among other things, the 1978 MOU made the establishment of regulatory requirements for fire protection and security matters at waterfront LNG plants an exclusive USCG responsibility").

[17] *See* Memorandum of Understanding Between the United States Coast Guard and the Research Special Programs Administration for Regulation of Waterfront Liquefied Natural Gas Facilities, https://www.phmsa.dot.gov/about-phmsa/1986-memorandum-understanding-between-uscg-and-rspa-waterfront-lng (May 16, 1986).

[18] Fire Protection and Security of Waterfront Liquefied Natural Gas Facilities, 52 Fed. Reg. 674 (Jan. 1987).

[19] *Id.*

b. Construction and Operation Inspections

PHMSA is best equipped to be the lead agency responsible for the operations and safety inspections of LNG facilities. PHMSA should memorialize this approach by revising its 2004 MOU with FERC and USCG[20] and then codify the agreed upon separations in inspection authority for pre-construction and post-construction operations.

FERC examines the safety of LNG facilities through its National Environmental Policy Act (NEPA) and Natural Gas Act certification authority. FERC evaluates the safety impacts of proposed interstate LNG projects and imposes conditions in its authorization certificate that operators must accept to obtain the required certificate. PHMSA has authority through the Pipeline Safety Act, specifically 49 U.S.C. § 60103. USCG has regulatory authority over LNG facilities which impact the safety and security of port areas and navigable waterways.[21] In 2004, the three agencies agreed to cooperate in inspections and operational reviews of LNG facilities.[22] That MOU is still active today. In 2018, FERC and PHMSA entered into a second MOU.[23] While that agreement was mostly focused on the LNG permit application process, the agencies did agree to assist each other by sharing findings from operational inspections. While these MOUs established a process for each agency to either participate in the same inspection[24] or share findings,[25] in practice, all of these agencies conduct their own inspections. These duplicative actions consume valuable resources as company and agency personnel prepare for and participate in each inspection.[26]

Having two different agencies conduct inspections of operations creates confusion. FERC often imposes obligations that are inconsistent with Part 193 requirements. For example, PHMSA requires operators to install seismic monitoring instrumentation that can measure the ground

---

[20] Interagency Agreement Among the Federal Energy Regulatory Commission, United States Coast Guard, and the Research and Special Programs Administration for the Safety and Security Review of the Waterfront Import/Export Liquefied Natural Gas Facilities, https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/InteragencyAgreementLNG%2CFeb2004.pdf (Feb. 2004).
[21] *Id.* at 2.
[22] *Id.* at 4 (III.B).
[23] Memorandum of Understanding Between the Department of Transportation and the Federal Energy Regulatory Commission Regarding Liquefied Natural Gas Transportation Facilities, https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/news/64706/ferc-phmsa-mou.pdf (Aug. 31, 2018).
[24] Interagency Agreement Among the Federal Energy Regulatory Commission, United States Coast Guard, and the Research and Special Programs Administration for the Safety and Security Review of the Waterfront Import/Export Liquefied Natural Gas Facilities, https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/InteragencyAgreementLNG%2CFeb2004.pdf (Feb. 2004).
[25] Memorandum of Understanding Between the Department of Transportation and the Federal Energy Regulatory Commission Regarding Liquefied Natural Gas Transportation Facilities, https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/news/64706/ferc-phmsa-mou.pdf (Aug. 31, 2018).
[26] A preliminary estimate of the costs per large-scale operator to prepare for an inspection on an annual basis amounts to $365,000. This figure was calculated based on the preparation time needed (80-120 hours each for procurement and construction, engineering, and regulatory personnel) and the salaries for the relevant personnel. Additional costs would be needed for P&ID construction walkdowns and preparation for PHMSA meetings. Finally, operations inspection personnel would need to prepare and attend agency inspections.

motion impacting containers or tank systems.[27] Yet, FERC staff require operators to install free-field seismic monitoring and in some cases, complete an additional seismic study to determine if additional on-tank monitoring is needed. FERC also requires operators to adhere to the International Society of Automation's ISA-TR84.00.07 (Guidance on the Evaluation of Fire, Combustible Gas, and Toxic Gas System Effectiveness) for flammable and combustible gas detection and flame and heat detection and uses a changing interpretation of "cascading damage" to further modify the design from an ISA-TR84.00.07 study. This document is not incorporated in NFPA 59A-2001 or Part 193.

FERC also requires that projects must have fire resistant cable for emergency systems that can withstand a minimum 20-minute fire exposure. Under PHMSA requirements, emergency shutdown systems must be protected against failure due to a fire exposure of at least 10 minutes. Finally, FERC requires that operational maintenance and testing procedures for fire protection shall be in accordance with NFPA 59A-2019. This goes beyond the requirements of Part 193.

PHMSA should reevaluate its MOUs and establish itself as the primary agency responsible for operation and safety inspections of LNG facilities. PHMSA should also amend its scope provision, § 193.2001(a), to clearly state that Part 193 governs the design, installation, construction, inspection, testing, operation, and maintenance of LNG facilities. This amendment would be consistent with sections 60103(b) and (d) of the Pipeline Safety Act.[28]

c. Emergency Response Plans

Certain LNG operators also face duplicative regulations governing emergency response plans. PHMSA,[29] USCG,[30] and FERC[31] all have different requirements for emergency response plans and varying review intervals for this documentation. The 2004 MOU notes that "[t]he Participating Agencies [FERC, USCG, and RSPA] further agree to cooperate in the inspection and operational review of LNG facilities, as appropriate."[32] However, there does not appear to be any coordination between the agencies on this topic. PHMSA should update the 2004 MOU to establish coordination for emergency response purposes and then codify the division of responsibility, as it applies to Part 193.

[27] Section 4.1.3.11 of NFPA 59A-2001.

[28] 49 U.S.C. § 60103(b) and (d)(Standards for liquefied natural gas pipeline facilities).

[29] *See* 49 CFR § 193.2509(b).

[30] 33 CFR § 127.307.

[31] Emergency Response Plans are required to be submitted to FERC as a submittal for compliance with the relevant environmental condition to gain approval to advance a project to the phase of "site preparation."

[32] Interagency Agreement Among the Federal Energy Regulatory Commission, United States Coast Guard, and the Research and Special Programs Administration for the Safety and Security Review of the Waterfront Import/Export Liquefied Natural Gas Facilities, https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/InteragencyAgreementLNG%2CFeb2004.pdf (Feb. 2004) at 4.

2. Cross-Coordination and Acceptance of Compliance with Analogous Requirements

Question A.2: For LNG facilities over which PHMSA shares regulatory authority with another Federal agency, should PHMSA consider an LNG facility's compliance with analogous regulatory requirements or guidance issued by those other agencies in evaluating compliance with existing part 193 requirements or (should they be incorporated by reference into part 193 regulations) NFPA 59A–2023? Please identify those analogous requirements of PHMSA and other Federal agencies.

a. Security Requirements

As discussed above, PHMSA should allow USCG to serve as the primary regulator of security requirements at waterfront LNG facilities adjoining navigable waters of the United States and codify this exemption in Part 193. If PHMSA chooses not to take this action, then it should accept an operator's compliance with the Maritime Security Facilities requirements[33] when evaluating whether that operator has satisfied 49 CFR Part 193, Subpart J (Security Requirements). There would be no safety concern in doing so because USCG security requirements are consistent with PHMSA's and USCG inspects more frequently. Both USCG[34] and PHMSA[35] require Facility Security Plans and procedures for LNG Facilities. Both agencies have similar approaches to security training requirements.[36] USCG relies on an annual inspection for security while PHMSA inspects most LNG facilities every three years. USCG also conducts spot security inspections. If an operator is subject to 49 CFR Part 193 and 33 CFR Part 105, then PHMSA should accept compliance with Part 105 to satisfy Part 193 security requirements.

b. Additional Coast Guard Requirements

LNG operators must also contend with overlapping PHMSA and USCG regulations in other areas. For instance, operators must meet both PHMSA and USCG requirements for auxiliary power systems, which may extend across PHMSA's and USCG's jurisdictions. PHMSA requires auxiliary power for any means of communication, emergency lighting, firefighting systems, and security lighting and monitoring systems.[37] USCG requires emergency power for emergency shutdown devices, communications, firefighting equipment and emergency lighting.[38] The USCG requirements are updated to reflect more recent publications of NFPA 59A (currently NFPA 59A-2019) while PHMSA directs compliance with the 2001 edition. This disconnect creates unnecessary regulatory burdens.

[33] 33 CFR § 105 (Facility Security Plan, annual inspection, and training).
[34] 33 CFR § 127.307.
[35] 49 CFR § 193.2509.
[36] *See* 49 CFR §§ 193.2709, 193.2715, and 33 CFR § 105.
[37] 49 CFR §§ 193.2445, 193.2519, 193.2613, and 193.2915.
[38] 33 CFR § 127.107.

c. Occupational Safety and Health Administration

Both PHMSA[39] and OSHA[40] require personal protective equipment (PPE) for emergency response and/or fire brigade duties. Both agencies also have separate requirements for tagging of equipment to prevent inadvertent operation for safety purposes.[41] PHMSA should accept compliance with OSHA's requirements for both PPE and lockout/tagout for LNG facilities. *See* response to Question D.13 for additional discussion.

B. Scope of Facilities Subject to Part 193

1. Different Categories of Facilities

> **Question B.1:** How many of each of these categories of LNG facilities (baseload, peak-shaver, temporary, or mobile) are projected to come into existence over the next two decades?
>
> What function(s) do they each currently serve in the interstate natural gas transportation system, and are there any emerging applications for those facilities?

There are more than 170 LNG facilities in the United States.[42] According to FERC, there are eight existing FERC-regulated LNG export terminals.[43] There currently are an additional eight approved projects at export facilities (or new facilities) that are under construction.[44] Some of these projects are expansions of an existing LNG Plant. There are twelve FERC approved projects that are not currently under construction.[45] There is one additional facility that is approved but not under construction that will be regulated by the Maritime Administration (MARAD) and USCG. Finally, there are twelve existing import terminals (ten regulated by FERC and two subject to MARAD and USCG requirements), another twelve import terminals with approvals but not constructed (ten are FERC-regulated and two are subject to MARAD and USCG requirements), and one proposed facility not yet approved.[46]

There are 12 FERC-regulated peak shaver facilities[47] and 65 non-FERC intrastate peak shaving facilities.[48] The Associations note that public gas systems frequently use "peak-shaving" and "temporary" LNG facilities to supplement pipeline supply during high-demand periods or to meet construction outages. With the continued growth of data centers and potential retirement of electric generation facilities, some pipeline systems may need to develop LNG facilities to support the new growth. Data center locations continue to be proposed and may impact future development

---

[39] 49 CFR §§ 193.2511(a) and 193.2801.
[40] 29 CFR §§ 1910.132 and 1910.156.
[41] 49 CFR § 193.2603(e) and 29 CFR § 1910.147.
[42] *See* https://www.ferc.gov/natural-gas/lng (last accessed on May 6, 2025).
[43] *Id.*
[44] *See* https://www.ferc.gov/media/us-lng-export-terminals-existing-approved-not-yet-built-and-proposed (last accessed on June 9, 2025).
[45] *Id.*
[46] *Id.*
[47] https://www.ferc.gov/media/ferc-jurisdictional-peakshavers-10 (last accessed on June 9, 2025).
[48] https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids (last accessed on July 3, 2025).

of LNG facilities. Several systems are actively exploring projects to expand their peak shaving capacity.

2. Material Differences Between Types of Facilities

Question B.2: Are there material differences in the characteristics (e.g., capacity or size; physical processes) of and among those categories of LNG facilities that merit distinguishable treatment under part 193?

What proportion of each category of LNG facilities are operated by ‘‘small entities’’ (small businesses, small organizations, or small government jurisdictions) as defined in the Regulatory Flexibility Act (5 U.S.C. 6010 et seq.) and its implementing regulations?

Each type and size of LNG facility presents a different risk profile and should not be regulated the same. Large-scale/baseload, small-scale/peak shavers, satellite, and mobile or temporary facilities have material differences that PHMSA should consider in developing new regulations. These differences include storage capacity, transfer operations (vessel, truck, rail), hazard footprint, geographical size (physical footprint), equipment (liquefaction, vaporization), operations (baseload, peak shaver, temporary, and mobile), intended use of LNG (domestic consumption, export), process complexity, staffing, and ancillary processes (pre-treatment).

PHMSA should consider developing "fit for purpose" regulations based on the risk presented by each type of LNG facility and not apply a "one size fits all" philosophy. PHMSA currently defines an LNG facility as “a pipeline facility that is used for liquefying natural gas or synthetic gas or transferring, storing, or vaporizing liquefied natural gas.”[49] This definition is overly broad and merits revision.

As such, the Associations propose the following definitions:

Large-Scale/Baseload LNG Facility. A plant that operates throughout the year to provide gas supply and exceeds the limitations of a small-scale/peak shaver LNG facility.

Small-Scale/Peak Shaver LNG Facility. A plant that is used for storing surplus natural gas for use during peak demand periods or meets the limitations specified below:

(1) LNG Storage capacity complies with <u>one</u> of the following:

- Individual LNG container water capacity not exceeding 264,000 gal (1000m^3) water capacity with an aggregate 1,056,000 gal (3997m^3) water capacity of LNG storage constructed in accordance with the ASME Boiler and Pressure Vessel Code.
- LNG tank systems with an aggregate capacity not exceeding 1,056,000 gal (3997m^3) water capacity of LNG storage.

[49] 49 CFR § 193.2007.

(2) Aggregate mass of ignitable fluids, excluding methane and LNG, not exceeding 25,000 lb (11,340 kg) and individual tanks with a storage capacity not exceeding 10,000 lb (4536 kg)

(3) Toxic fluids with a 60-minute AEGL-2 of 10,000 ppm or less and an aggregate mass of toxic fluids not exceeding 25,000 lb (11,340 kg) and individual tanks with a storage capacity not exceeding 10,000 lb (4536 kg)

(4) LNG container liquid line penetrations not exceeding 6 in. (15.24 cm) nominal pipe size

(5) LNG container design pressure not exceeding 300 psi (2068 kPa)

Satellite LNG Facility. A plant that does not include process equipment to convert natural gas to LNG. Instead, trucks deliver LNG for storage on site. Satellite plants typically inject natural gas into distribution pipeline systems.

Mobile or Temporary LNG Facility. Mobile LNG plants are not permanent infrastructure and are designed to be easily moved, *e.g.* skid-mounted or trailer-mounted, or otherwise portable. Temporary LNG plants are those used for short-term applications, *e.g.*, in service 180 days or less, to provide supply during planned construction and maintenance activities or in cases of unplanned events such as peak shaving to meet unanticipated demand.

C. Reporting Requirements

Question C.1: Is there information required in the annual, incident, and safety related condition reports required by PHMSA regulations with limited or no safety value [for] any of the categories of part 193- regulated LNG facilities?

Yes, current regulations require the reporting of information with limited or no safety value, as described below. The Associations recognize that PHMSA uses reporting as an input for its risk modeling methodology to schedule inspections, however, several reporting requirements could be streamlined or modified. In addition, certain provisions in the reporting instructions should be codified.

1. Required Reporting with Little to No Safety Value

a. Safety-Related Condition Reporting

The Associations recommend that PHMSA review its safety-related condition (SRC) reporting requirements and clarify that SRC reporting is <u>not</u> required for LNG facilities that are in testing or in the final stages of construction, *i.e.*, commissioning or initial start up. The intent of SRC reporting was to notify the agency of "glaring, hazardous conditions which might, if left to linger, constitute an imminent danger or potentially cause an incident."[50] LNG facilities that are in the

[50] In 1986, Congress directed RSPA to require operators to report unsafe conditions through a written notice to the Agency. *See* Pub. L. 99-516, § 3(a), 100 Stat. 2965, 2965 (1986) (codified as amended at 49 U.S.C. § 60102(h)). Congress expressed concern that operators were not correcting unsafe conditions and believed that government intervention could prevent a subsequent incident or accident. *See* H.R. Rep. No. 99-779 (1986). *See also,* Reporting

final stage of construction are unlikely to meet this characterization. PHMSA performs inspections and walkdowns throughout construction and the commissioning phases of a project which eliminates the opportunity for any 'glaring' condition that would be left to linger prior to operation.

In addition, as currently written, 49 CFR § 191.23(a) is open to interpretation and confusion. PHMSA should add definitions for "structural integrity" and "reliability." In § 191.23(a), PHMSA mandates the reporting of a safety-related condition that involves "[a]ny crack or other material defect that impairs the structural integrity or reliability of a UNGSF or an LNG facility that contains, controls, or processes gas or LNG."[51] The term "structural integrity" is more closely associated with foundations and structures, which causes confusion when a component is subject to the reporting requirement. "Reliability" is often interpreted as a time-based metric for asset performance. Large-scale/baseload, small-scale/peak shaver, and satellite LNG piping and vessel components are designed to be operational for decades, so it is hard to evaluate the "reliability" definition. Clear definitions would aid industry and PHMSA inspectors in evaluating and reporting SRCs.

b. National Pipeline Mapping System

The Associations acknowledge and understand that PHMSA has the statutory authority to require the submission of geospatial data.[52] However, unlike pipelines, large-scale/baseload, small-scale/peak shaver, and satellite LNG facilities are visible to the public. Requiring these facilities to annually report to the National Pipeline Mapping System (NPMS) provides no safety value or additional information to the public. PHMSA states in section 191.29(b) that "[i]f no changes have occurred since the previous year's submission, the operator must comply with the guidance provided in the NPMS Operator Standards manual available at www.npms.phmsa.dot.gov or contact the PHMSA Geographic Information Systems Manager at (202) 366-4595."[53] The Operator Standards manual further provides that "[a] notification of no changes, in place of a data submission, fulfills the annual NPMS submission requirement."[54] Operators are directed to send a no change notification via email to NPMS staff.[55] The Associations agree with this email approach but it is not codified in section 191.29. Instead of directing operators to the Standards Manual for guidance, PHMSA should include an exception in section 191.29 for those LNG facilities where no changes occurred during the reporting period.

c. Annual Reporting

There are several sections of the LNG Annual Report (Form F7100.3-1) that do not provide appreciable safety value. In Part D, the agency requires operators to report emergency shutdowns

---

Unsafe Conditions on Gas and Hazardous Liquid Pipelines and Liquefied Natural Gas Facilities, 53 Fed. Reg. 24,942, 24,943 (July 1, 1988)("…operators were expected to disclose only glaring, hazardous conditions, which might, if left to linger, constitute an imminent danger or potentially cause an incident.").

[51] 49 CFR § 191.23(a)(4).

[52] 49 U.S.C. § 60132(a)(1)-(4).

[53] 49 CFR § 191.29(b).

[54] National Pipeline Mapping System, LNG Plant Submission Process, https://www.npms.phmsa.dot.gov/SubmissionProcessOverviewLNG.aspx (last accessed on June 25, 2025).

[55] *Id.*

(ESDs) that are unrelated to an incident.[56] Operators must submit the number of ESD actuations due to false signal, maintenance, or a non-safety event. This information does not provide any appreciable safety value. This is particularly true at a peak shaving facility, where liquefaction or vaporization occurs only during a limited portion of the year. For the remainder of the time, the facility operates in a "holding-mode" managing boil-off.

PHMSA should consider incorporating API 754 to report leaks based on potential safety consequence. Leaks identified through a leak detection program are detected using optical gas imaging (OGI) cameras and often represent very small leak rates that would not have been discovered through conventional means, do not present a safety risk, and should be considered a non-hazardous release within Part C of the LNG Natural Gas Annual Reporting Instructions F 7100.3-1. PHMSA should use API 754 to distinguish between potential safety consequence to avoid misperceptions in the leak data.

d. Incident Reporting

PHMSA should revise its LNG Incident Form (PHMSA F7100.3), specifically Part C (lines C1f-C1h) which collects the cost of commodity released. Part 191 excludes the cost of gas lost for purposes of the definition of an incident yet the operator must still calculate it and include this amount as part of an incident report.[57] This type of information does not advance safety.

The Associations also seek clarity on how PHMSA applies the property damage threshold for purposes of incident reporting. While the Part 193 incident reporting instructions provide that property damage includes physical damage to the property of others, cost of the investigation, remediation of any site not owned or operated by the operator, and the replacement value of any equipment damaged due to the incident,[58] the agency has issued conflicting interpretations on this topic. In PI-10-0026, PHMSA concluded that "the cost of the damage to a vehicle striking a gas pipeline facility would normally be included in determining whether the incident was reportable."[59] Since the vehicle is responsible for the leak in this scenario, it should not be included in an operator's calculation of property damage. This interpretation should be rescinded. *See* Question D.14 for additional discussion.

e. Construction Notifications

PHMSA should amend sections 191.22(c) and 193.2011 to clarify that construction notifications are not required for those events that are already subject to design review notifications.[60]

---

[56] Part D of the LNG Annual Report (F 7100-3.1).
[57] Instructions For Form PHMSA F 7100.3 (Rev. 04-2011) Incident Report – Liquefied Natural Gas (LNG) Facilities, at 14.
[58] *Id*. at 13.
[59] Letter of Interpretation to Jason Montoya, Bureau Chief, New Mexico Public Regulatory Comm'n, PI-10-0026 (June 14, 2011).
[60] 49 CFR § 190.405.

2. Duplicative Reporting Requirements

Question C.2: Is there information required in the reports that is duplicative with the information required to be submitted to other State or Federal regulatory authorities?

Yes, several sections of the LNG annual report (Form 7100.3-1) are duplicative with FERC reporting requirements. Operators of FERC-jurisdictional LNG facilities are already required to submit semi-annual reports that include the same data elements PHMSA requests in its annual report. For example, the FERC semi-annual report collects information on abnormal operating conditions. This includes ESDs, leak/spill information, and any equipment malfunctions. Requiring the same data to be refiltered to meet the slight variances in reporting categories and then resubmitted at a different timeline for PHMSA purposes offers no additional value and imposes an unnecessary administrative burden. This approach does not comply with the Paperwork Reduction Act[61] or the Office of Management and Budget's implementing regulations addressing paperwork burdens.[62] OMB approval of an agency's proposed collection of information requires a demonstration that the agency "has taken every reasonable step to ensure that [it] ... is the least burdensome necessary for the proper performance of the agency's functions to comply with legal requirements and achieve program objectives."[63] If another agency is already collecting this information, this is not the least burdensome approach.

Other duplicative reporting requirements exist for specific types of LNG facilities. Operators subject to an EPA Title V permit are required to submit the same leak data to both EPA and PHMSA (Part C of PHMSA's annual report). FERC also asks for flaring logs during inspections and as part of the semi-annual report. This overlap not only increases regulatory burden but also risks misrepresenting emissions data by counting the same leak twice under different frameworks. *See* Question C.1.c in this comment document for additional discussion. Finally, for those facilities regulated by the USCG, operators must report security breaches to PHMSA,[64] USCG,[65] and FERC.[66]

3. Incremental, Per Unit Costs and Benefits of Requiring SRC Reporting During Commissioning and Initial Start Up

Question C.3: What incremental, per-unit costs and benefits may arise from amending § 193.2011 to clarify that safety-related condition reporting would be required not only for ''in-service'' LNG facilities, but also safety-related conditions that occur during commissioning and initial start-up?

As discussed in response to Question C.1, the Associations do not support the application of SRC reporting requirements to conditions that may occur during commissioning and initial start-up.

[61] 44 U.S.C. §§ 3501–3521.
[62] 5 CFR § 1320.1 *et seq.*
[63] 5 C.F.R. §1320.5(d)(1).
[64] *See* Part D of PHMSA Liquefied Natural Gas Annual Report Form (F 7100-3.1).
[65] 33 CFR § 101.305; *See also,* 33 CFR § 105.200(b)(12).
[66] *See* reporting requirements in a facility's environment assessment or environmental impact statement. Security breaches must be reported within 24 hours.

If PHMSA were to proceed with this modification, the agency should clarify the definitions of "commissioning," and "initial start-up." Commissioning activities can span several months and involve a range of preparatory and testing activities before full operational status is achieved. Without clear definitions, there is a risk of misinterpretation and inaccurate reporting, as well as unnecessary staffing and potential property tax implications that increase costs without improving safety.

The Associations will evaluate the potential costs if PHMSA pursues this approach.

D. Tensions Complying with NFPA 59A-2001

1. Issues with Managing Differences Between Modern Standards and NFPA 59A-2001

Question D.1:

Stakeholders have asserted that compliance with provisions of NFPA 59A–2001 has become increasingly impracticable as vendors and the industry itself employ more recent consensus industry standards in their activities. Please describe noteworthy examples of tension between NFPA 59A–2001 provisions referenced in current PHMSA regulations and more recent consensus industry standards.

It is increasingly difficult to comply with a 24-year-old standard, particularly one that incorporates even older industry documents as supplemental references. This disconnect creates increased engineering, construction, and documentation burdens. Engineering, procurement, and construction contractors are often required to spend considerable time reconciling differences and analyzing conflicts between various versions of NFPA 59A and Part 193 as well as supplemental references within NFPA 59A to determine what is required and which approach is the most conservative.

Having a risk-based approach for large-scale/baseload facilities (as set forth in section 110 of the PIPES Act of 2020) and a similar option for small-scale and peak shaver operators would relieve these tensions. Small scale and peak shaver operators have also identified the following Part 193 examples of complying with such an outdated standard.

a. Design for Wind and Snow Loads

The calculation of wind forces has created tension between PHMSA inspectors, operators, and contractors. Section 193.2067(b)(1) provides that operators must use ASCE 7-05 to calculate wind forces for shop fabricated containers of LNG or other hazardous fluids with a capacity of *not more than 70,000 gallons*.[67] All other LNG facilities are permitted to use an assumed sustained wind velocity of not less than 150 miles per hour, unless PHMSA makings a finding that a lower velocity is justified or the operator is able to provide adequate wind data and a probabilistic methodology.[68] Yet, in the LNG inspection questions, PHMSA states that the design process for LNG storage

[67] 49 CFR 193.2067(b)(1)(emphasis added). *See also,* PHMSA LNG Plant Requirements: Frequently Asked Questions D.1.

[68] 49 CFR § 193.2067(b)(2).

tanks and structures for wind and snow loads must meet the requirements of NFPA 59A-2001, section 4.1.4 and ASCE 7.[69]

During recent construction projects, PHMSA required the use of ASCE 7-05 to determine the wind speed in accordance with section 193.2067(b)(2), even though this tool is not incorporated by reference in that section. This issue resulted in a redesign of buildings that had already been purchased. If it had been clear that the use of this tool was expected, the buildings would have initially been designed to meet it. PHMSA should revise its inspection questions to be consistent with the regulations. If the intent is for operators to use ASECE 7-05 regardless of structure size, then PHMSA should clarify that approach in section 193.2067(b)(2).

b. Building Setback Requirements

Table 2.2.4.1 in NFPA 59A-2001 references distances from impoundment to buildings and property lines. In the subsequent versions of NFPA 59A, this table was revised to only reference property lines.[70] PHMSA inspectors interpret this table to require that all facility related buildings must meet these setback requirements. This unnecessarily increases the size of the facility and the potential exposure of longer piping runs. All buildings proposed within this setback distance are designed to withstand the hazards present and are involved in the LNG process. PHMSA should allow operators to follow Table 6.3.1 in NFPA 59A-2023 or other good engineering practices under a risk-based regulation.

c. Use of vacuum jacketed pipe

While vacuum jacketed pipe is an acceptable construction method in NFPA 59A-2023,[71] it is not currently allowed by section 193.2167 (Covered Systems). Operators would have preferred to use vacuum jacketed pipe but have been forced to install unjacketed pipe within a drainage dike to meet the requirements of the code. Alternatively, PHMSA should clarify what is considered a covered impounding system.

d. Overpressure protection requirements

Operators have to reconcile differences between pressure vessel codes and piping standards, as PHMSA regulations remain several editions behind in its incorporated references, thereby limiting the use of modern repair techniques and materials. Pressure testing methodologies in NFPA 59A-2001 are limited and do not align with modern industry standards. For instance, section 3.4.2 of NFPA 59A-2001 requires boilers and pressure vessels to be designed and fabricated to the 1992 edition of ASME *Boiler and Pressure Vessel Code* (BPVC). Contractors are generally unable or unwilling to design and construct equipment to such an outdated code. Contractors use the most recent edition of the ASME BPVC, which necessitates additional steps and cost to demonstrate equivalency with the 1992 edition. To comply with PHMSA's requirements, LNG facilities must

[69] *See* PHMSA Part 193 LNG Storage Tank Inspection Questions, 14 and 15 (referencing NFPA 59A-2001, section 4.1.4 and ASCE 7); *See also,* Design and Construction-Structures Inspection Questions, 3 and 4, ASME LNG Tank Inspection Questions, ; *See also,* section 193.2067.
[70] *See* NFPA 59A-2023, Table 6.3.1.
[71] NFPA 59A-2023, section 13.5(2).

either validate equivalency or follow alternative methods such as the one outlined in PHMSA's LNG FAQ D6.[72] This process can be costly and burdensome. For example, during a recent construction project, an operator incurred an additional $25,000-$30,000 to derate a pressure vessel and obtain new nameplates to meet PHMSA's outdated requirements. To reduce unnecessary costs, it is recommended that PHMSA incorporate the current edition of the ASME BPVC.

The use of the NFPA 59A-2001 standard has also been an issue with other agencies. In order to advance projects, operators are required by FERC in their authorization orders to adopt various versions of NFPA 59A. FERC has referenced up to five different versions of NFPA 59A in authorizing orders either directly within, or citing the standard as the basis for environmental conditions; including versions of NFPA 59A that are yet to be published, *i.e.,* NFPA 59A-2026. In some states, construction requirements set by state agencies can conflict with PHMSA regulations. For example, during a recent heater replacement project in New Jersey, the state required the new units to comply with the current revision of ASME BPVC to meet air quality standards.

Question D.1 (continued):

What incremental, per-unit costs (including, but not limited to, those arising from personnel having to compare operator practices with provisions of NFPA 59A–2001 referenced in current PHMSA regulations) arise from operators having to navigate those tensions?

In the example involving the BPVC discussed above, the operator's cost to demonstrate code equivalency and derate the equipment involved an additional cost of approximately $25,000 to $30,000.

2. Narrow Rulemaking to Update Only NFPA 59A-2001

Question D.2:

Should PHMSA consider a narrow rulemaking to update only the NFPA 59A standard to the 2023 edition and pursuing a broader part 193 update afterward?

No, the Associations oppose a narrow rulemaking focusing exclusively on updating the incorporated by reference edition of NFPA 59A. Such an action would not satisfy section 110 of the PIPES Act, in which Congress directed the agency to develop a risk-based approach for large-scale/baseload LNG facilities. The Associations urge PHMSA to proceed with a rulemaking to establish a risk-based approach for large-scale/baseload facilities with a similar option made available for small-scale/ peak shaver LNG facility operators. Small-scale and peak shaver operators have been waiting for decades for PHMSA to update the references in Part 193 to a more current edition of NFPA 59A. Additionally, some portions of 49 CFR Part 193 state the same exact wording as NFPA 59A-2001 and therefore citing a newer version of 59A may cause

[72] https://www.phmsa.dot.gov/pipeline/liquified-natural-gas/lng-plant-requirements-frequently-asked-questions#d6 (last accessed on June 24, 2025).

regulatory text changes to ensure the new version is properly captured.[73] The Associations urge PHMSA to evaluate which portions of NFPA 59A-2023 should be incorporated in Part 193 for small-scale/ peak shavers, satellite, and mobile or temporary operators that do not use a risk-based regulation, and update Part 193 as discussed in this comment letter.

While this issue is discussed in more detail in Question D.6, the Associations do not support a wholesale adoption of NFPA 59A-2023. Such an approach would increase the regulatory burden since not all provisions in the NFPA 59A-2001 standard are currently incorporated and NFPA 59A-2023 expands the requirements of 49 CFR Part 193 in several areas.

Question D.2 (continued):

What would the incremental costs and benefits be of an update of the NFPA 59A standard to 2023?

The Associations provide preliminary cost estimates of incorporating NFPA 59A-2023 in response to Question D.6.

3. Use of NFPA 59A-2001 Provisions Not Incorporated in Part 193

Question D.3:

To what extent do different categories of LNG facility operators generally comply with other NFPA 59A–2001 provisions (e.g., those governing operating and maintenance) not explicitly incorporated by reference in part 193?

With which of those NFPA 59A–2001 provisions do different categories of LNG facility operators generally comply?

With which do they generally not comply?

The level of adherence to NFPA 59A-2001 provisions that are not incorporated by reference varies across small-scale and peak shaver operators depending on if the facility was constructed prior to March 31, 2000, as referenced in § 193.2801.

[73] *See* Section 193.2501 ("In the event of a conflict between this part and NFPA-59A-2001, this part prevails.").

4. Use of More Recent Editions of NFPA 59A

Question D.4:

To what extent do different categories of LNG facility operators generally comply with provisions in more recent editions of NFPA 59A?

If so, which edition (e.g., NFPA 59A–2019 or NFPA 59A–2023) do operators generally follow?

Do operators generally conform their activities to the entirety of those more recent editions, or do they follow specific chapters or paragraphs of those more recent editions, but not others?

Do operators conform to more recent editions of NFPA 59A voluntarily or due to regulatory requirements imposed by another State or Federal regulatory authority?

During construction, some large-scale/baseload operators have relied on newer editions of NFPA 59A such as the 2019 version for purposes of design, repairs, and fire protection of marine transfer areas under USCG 33 CFR §§ 127.008(d), 127.101, 127.201(b) and (c), 127.405(a) and (b), and 127.603(a). LNG facilities under FERC jurisdiction follow specific sections and/or versions of NFPA 59A to comply with environmental conditions, including NFPA 59A versions 2006, 2019, 2023, and 2026.[74] These operators must follow specific chapters or paragraphs from recent editions (but not the entire standard) in order to advance projects with FERC.

Some states, including, but not limited to, Texas and Louisiana, have incorporated newer editions of NFPA 59A into their state regulations for facilities that are not subject to PHMSA regulations. As a result, operators subject to those state regulations must comply with these newer editions.

5. Incremental Costs of Incorporating Only Certain Provisions of NFPA 59A (2023)

Question D.5:

What incremental, per-unit costs and benefits would arise from substituting NFPA 59A–2023 provisions for the current reference to NFPA 59A–2001 provisions (or superseding part 193 provisions) in each of those subparts of part 193?

Should PHMSA exclude some NFPA 59A–2023 provisions from incorporation by reference in those subparts?

To which categories of LNG facilities should any NFPA 59A–2023 provisions pertinent to those subparts apply?

Large-scale/Baseload Facilities. The Associations maintain that any additional costs for large-scale operators could easily be avoided by developing a risk-based approach consistent with the requirements of section 110 of the PIPES Act.

Small-scale /Peak Shavers, Satellite, and Mobile or Temporary LNG operators (Cost savings from Incorporating 2023 Edition). For small-scale and peak shaver operators, PHMSA should consider incorporating section 4.7.2(3). That section provides that control centers shall have personnel "in

[74]NFPA 59A-2026 is yet to be published.

attendance during startup and shutdown of vaporization and liquefaction procedures and at transfer facilities, with exceptions described in Section 18.6 during any operations monitoring… or the facility has an automatic emergency shutdown system." Section 18.6.1.1 further provides that at facilities "with onsite control centers, operating personnel shall be permitted to leave the control room to perform scheduled field inspections or to address activities in the field related to the plant's operation."

This provision stands in contrast to 49 CFR § 193.2441(c) which mandates continuous attendance while any components under their control are in operation, unless control is being performed from another staffed control center.[75] PHMSA has then interpreted this regulation through guidance to mandate that continuous means "LNG facilities must have at least one person in the control center at all times (i.e. uninterrupted) while any of the components under the control center's control are in operation."[76] The agency also stated that section 193.2441 requirements "do[ ] not preclude plant operators…from taking short breaks in the area of the control center to attend to physiological needs."[77] Similarly, in a 2020 interpretation, PHMSA again noted "[Sec. 2441] requires that an LNG facility has at least one person in the control center at all times (i.e.[,] uninterrupted while any of the components under the control center's control are in operation. This does not preclude the LNG control center operator from taking short breaks in the area of the control center to attend to physiological needs."[78] Section 193.2441 and the associated interpretations would require at least two people to perform any necessary inspections outside the control center while maintaining compliance.

At small-scale/peak shaver LNG facilities, control centers should not be required to maintain continuous staffing during holding periods (i.e. periods of time when the facility is managing boil-off and liquefaction, vaporization, or equipment cooldown is not occurring). Requiring continuous staffing during these low-activity, minimal risk periods impose unnecessary operational burdens and staffing costs. These modifications to Part 193 would produce <u>cost savings</u> of approximately $540,000 - $700,000 per year for each one person-controlled facility.[79]

Operators would also obtain cost savings by extending testing intervals for relief valves. NFPA 59A-2023 addresses relief valve testing in section 18.10.10.7.2. If incorporated by reference, the testing interval for relief valve set points would be extended to intervals not exceeding 5 years plus three months. Relief valves on stationary LNG tanks would require testing every 2 calendar years,

---

[75] PHMSA Letter of Interpretation to William Hawkins (Dec. 2006). The Associations note that this interpretation is no longer available on PHMSA's website.

[76] In a 2006 interpretation, PHMSA stated that continuous "mean[s] that LNG facilities must have at least one person in the control center at all times (i.e., uninterrupted) while any of the components under the control center's control are in operation." PHMSA Letter of Interpretation to William Hawkins, (Dec. 2006) at 1. This interpretation is no longer available on PHMSA's website.

[77] *Id.*

[78] PHMSA Letter of Interpretation to Bryce Keener, PI #-20-0012 (July 8, 2020). PHMSA has not provided any further guidance on this point and has not defined the limits of the term 'physiological needs'.

[79] This figure was calculated by using the two employees at each control center and including overtime and benefits. It does not include any technological resolution (*i.e.,* carrying an iPad on rounds).

not to exceed 39 months. A preliminary estimate of the cost savings for one small-scale/peak shaver facility would amount to a five-year savings of $685,464 per facility.[80]

Large-scale/baseload, small-scale/Peak Shavers, Satellite, and Mobile or Temporary LNG Operators (Cost Increases from Incorporating 2023 Edition). For all operators,[81] there are several areas where requiring compliance with NFPA 59A-2023 would increase costs. Chapter 3[82] expands the definition of a component to include electrical systems and security control equipment. These devices would then need to be tested at the prescriptive frequency required in Chapter 18[83] based on the current Part 193 definition of a control system.

Section 5.3.2.3 would require a HAZOP contractor to do comparison scenarios for design spills for each plant area at an estimated cost of $50,000-100,000.

Section 10.6 adds a requirement that fire protection on pipe supports be designed according to recognized standards (such as API RP 2218). There is no such requirement within NFPA 59A-2001. The cost of implementation could be significant. If existing fireproofing is damaged or deteriorated, facilities might be required to be removed and replaced with material and methods that meet recognized standards. This could lead to increased maintenance costs and downtime, especially if the existing fireproofing was not installed to a recognized standard.

Section 11.7.2 introduces a new requirement for conducting a cybersecurity vulnerability assessment of both the process control system and safety instrumented systems every two years. LNG facilities are already subject to cybersecurity mandates issued by either the TSA or USCG, which include similar assessment requirements. There is no need for additional overlap and duplicative requirements.

Compliance with section 13 would lead to $10,000,000 for retroactive application of impoundment and diking requirements. *See* Question D.11 for more information.

Section 15.9.2 increases the minimum lighting requirements for the hazardous fluid transfer area from 2.2 lux to 54 lux at the transfer connection and 11 lux at other work areas.[84] Artificial lighting can interfere with the behavior of nocturnal animals, seemingly having the greatest impact on nocturnal migrating birds, causing disorientation and collision with over-lit structures. Other agencies have expressed concern over potential impacts associated with artificial lighting.[85] This will add cost as facilities had to previously meet the 2.2 lux requirement. One peak shaver operator estimated that it would cost approximately $45,000 per facility to accommodate this new

---

[80] This figure was calculated by estimating 154 valves per facility, a weekly cost of $34,273 for a contract testing company set a total of five weeks to complete the testing. The Associations then added the average cost per relief valve of $1112. This produces an annual cost savings of $171,366 or $685,464 over a five-year window.

[81] The Associations maintain that any additional costs for large-scale operators could easily be avoided by developing a risk-based approach consistent with section 110 of the PIPES Act.

[82] Section 3.3.4.

[83] Section 18.10.10.5.

[84] This differs from lighting requirements specified by other Federal Agencies such as OSHA 29 CFR 1926.56 Table D-3.

[85] *See* Scoping Comments from the U.S. Fish and Wildlife Service comments on the Elba Liquefaction Optimization Project (Docket No. CP 23-375)(Mar. 13, 2024)("Artificial lighting has been well-documented to disorient or misorient nesting female sea turtles and hatchling sea turtles emerging from the nests and attempting to go to the ocean.").

requirement.[86] PHMSA should establish an exception for LNG facilities that do not transfer products at night.

Section 16.2.1.3 requires a new prescriptive fire protection evaluation to be performed that is currently not within Part 193. Section 16.2.1.3 of NFPA 59A-2023 requires LNG facilities to review and update their fire protection evaluation every two years. However, the standard does not clarify the qualifications required for conducting the review and update. In the absence of further guidance, it is reasonable to assume that such evaluations must be performed by individuals with knowledge of fire protection engineering standards, rather than by on-site personnel or engineers without specialized training. The cost for a full-site fire protection evaluation at a small-scale/peak shaver facility is between $30,000 and $150,000[87] based on the size of the facility. This represents a significant recurring expense, particularly if no substantive changes have occurred at the facility. Unless there has been a modification to equipment location, sizing, or fire protection systems (e.g., fire or gas detectors, low-temperature detectors, fire monitors), a review and update of the fire protection evaluation should not be necessary. A review and update by a qualified fire protection engineer (or contractor) should only be mandated when such changes are identified. This approach would maintain safety while reducing regulatory burdens. Fire studies updates as part of a capital project upgrade should also be permitted to satisfy the two-year requirement. Section 16.2.1.4 expands upon section 16.2.1.3 with additional prescriptive timelines that are currently not within 49 CFR Part 193. Establishing a rigid timeline for implementing modifications, expansions, or replacements recommended by a fire protection evaluation is overly restrictive, particularly for peak shaving and other smaller LNG facilities with limited budgets. Such a requirement does not adequately account for the operational and financial planning cycles of these facilities. For example, if a fire protection review is completed after the annual budget has been finalized, the facility may be unable to secure funding to implement the recommended changes within a one-year timeframe. Additionally, operational constraints or seasonal activity at the facility may further delay implementation. These requirements do not account for a risk-based approach. PHMSA should consider allowing flexibility in the implementation timeline for fire protection system changes. The schedule should be determined collaboratively between the operator and PHMSA, considering the risk level associated with the recommended change, the facility's budget cycle, and other operational considerations. This approach would ensure both safety and practical feasibility.

Section 16.2.1.1.5 would create costs of $30,000-$150,000 per professional study depending on the size of the facility. This does not include costs of any recommended installs, which would not be required to implement on a specific timeline.

Section 16.8 would create duplicative regulations on marine LNG facilities that are covered under 33 CFR 105 security requirements.

Paragraph 16.8.3 includes additional requirements in comparison to 49 CFR § 193.2905(a).

---

[86] This estimated was developed by calculating the cost per fixture of $1,500 - $2,000 and at least 15 fixtures plus an additional cost of $15,000 for a lighting survey to determine where the operator needed to add lighting.

[87] This does not include installation costs which would be required to be implemented on a specific timeline.

Section 16.8.7 removes the language of ""between sunset and sunrise,"" in 49 CFR § 193.2911, making the requirement for security lighting necessary for the entire day. The cost of electricity has not been calculated but it would likely double.

Paragraph 18.3.8 includes additional requirements compared to 49 CFR 193.2503(f).

Paragraph 18.4.3 includes additional requirements compared to 49 CFR 193.2509(b)(1).

Paragraph 18.10.3.1 includes additional prescriptive requirements not currently within 49 CFR 193. Section 193.2609 requires inspections of support systems but does not specify how often. NFPA 59A-2023 provides for an annual inspection of support systems. The Associations have calculated an estimate of $500,000 to retain year-round inspectors to do inspections and reports on **all** component foundations.

Paragraph 18.12.1 includes additional requirements compared to section 193.2639.

Paragraph 18.12.4 includes a more prescriptive requirement than section 193.2719(b).

The Associations intend to update its cost estimate in response to the next public comment opportunity.

6. Incremental Costs of Wholesale Incorporation of NFPA 59A (2023)

Question D.6:

What incremental, per-unit costs and benefits would arise should PHMSA propose to incorporate by reference the entirety of NFPA 59A– 2023?

Please provide those estimated, incremental costs and benefits on a per chapter basis where possible, highlighting provisions in each NFPA 59A–2023 chapter for which compliance would be particularly burdensome or costly for particular categories of LNG facility operators.

The Associations do not recommend that PHMSA incorporate and reference the entirety of NFPA 59A-2023. Rather, for small-scale/peak shaver, satellite, mobile or temporary operators, PHMSA should continue with its current practice and incorporate specific sections of NFPA 59A-2023 (Siting, Design, Construction, Equipment and Fire Protections) with a few exceptions as discussed in these comments. For large-scale/baseload operators, PHMSA should develop risk-based regulations consistent with section 110 of the PIPES Act.

The Associations acknowledge that the 2023 standard reflects the technology available today for the design and construction of LNG facilities. However, PHMSA must conduct an analysis of the incremental costs relative to safety and overlap with other agencies' regulations as part of any specific proposal. For instance, if incorporated, chapters 18 (Operating, Maintenance and Personnel Training) and 19 (Performance-Based LNG Plant Siting Using Quantitative Risk Analysis) of NFPA 59A-2023 would present different obligations compared to the requirements of other agencies. One operator estimates a potential cost of $506,500-$3,492,500 for incorporating all of NFPA 59A-2023.

The Associations also have concern with the retroactivity provisions set forth in NFPA 59A-2023. It is well-understood that PHMSA is precluded from applying design, installation, construction, initial inspection, or initial testing standards to existing LNG facilities.[88] Yet, if PHMSA were to proceed with a wholesale incorporation of NFPA 59A-2023, the agency would have to address retroactive provisions within the standard. Sections 1.3.2 and 1.33 provide that "the authority having jurisdiction" may apply sections of the standard retroactively.[89] Section 1.3.1 provides that "[w]here specified, the provisions of this standard shall be retroactive."[90] Further, the requirements in chapters 16 (fire protection system modifications)[91] 18 (corrosion control),[92] and 19 (alternate plant siting),[93] among others, would create retroactive impacts on existing facilities.

Compliance with 49 U.S.C. § 60103(c)(1) is not only statutorily required but it is extremely important for operators of existing LNG facilities. Requiring retroactive compliance would be impractical and unachievable, as compliance may require significant (and expensive) changes to the equipment and/or processes comprising the facilities and could create a disincentive for an operator to make any modifications. Constructing new infrastructure at existing LNG facilities has numerous advantages, including minimizing new landowner impacts, reducing overall footprint for the new facilities by sharing existing infrastructure (*i.e.,* LNG storage tanks, marine loading facilities, emergency infrastructure), leveraging experience of existing personnel and cost-effectiveness.

PHMSA should also address the meaning of "the authority having jurisdiction." In any rulemaking involving LNG Facility siting, design, installation, construction, inspection, testing, operation, and maintenance, PHMSA should clearly and explicitly state that they are the federal authority having jurisdiction, except where that authority has been delegated to the states. PHMSA should also state that the retroactivity portions of any standard incorporated by reference, including NFPA 59A, do not apply to existing LNG Facilities.

7. Mandatory vs Permissive Provisions in NFPA 59A (2023)

Question D.7:

Which mandatory provisions of NFPA 59A–2023 should be made permissive if incorporated into the PHMSA's part 193 regulations?

Are there certain mandatory elements of NFPA 59A–2023 that should remain mandatory for some categories of LNG facilities but not others?

Should any non-mandatory provisions in NFPA 59A–2023 be mandatory, and what incremental, per-unit costs and benefits would arise?

[88] 49 U.S.C. § 60103(c)(1).
[89] NFPA 59A-2023, sections 1.32 and 1.33 (2023).
[90] *Id.*, section 1.3.1.
[91] *Id.*, section 16.2.1.4.
[92] *Id.*, section 18.10.13.8.3.
[93] *Id.*, section 19.1.4.

Consistent with section 110 of the PIPES Act of 2020, PHMSA should develop risk-based regulations for large-scale/baseload LNG facilities.

Fire Protection Review. For small-scale/peak shavers, the Associations recommend incorporating the fire protection review sections (16.2.1.3 and 16.2.1.4) but codifying these sections strictly as permissive. Large-scale/baseload operators under a risk-based regulatory approach consistent with section 110 of the PIPES Act would allow an operator to address a change evaluation under the safety management system eliminating the need for the prescriptive requirements of 16.2.1.3 and 16.2.1.4. *See* Response to Question D.5 for additional explanation regarding the concerns with these sections.

Control Center Staffing: As discussed above, for small-scale/peak shavers, the Associations recommend incorporating section 4.7.2(3) without modification.

Prescriptive Timelines. Sections 18.10.10.1, 18.10.10.3, 18.10.10.5, and 18.10.13.6 contain prescriptive timeframes that would conflict with any risk-based approach. These should be permissive or not incorporated at all.

Relief Valve Testing: For those operators not using a risk-based approach, PHMSA should replace the relief valve testing requirements in 49 CFR § 193.2619 with sections 18.10.10.7.2 of NFPA 59A-2023 and make these provisions permissive. Section 18.10.10.7.2 allows relief valve testing in accordance with API 576 *Inspection* of *Pressure Relieving Devices*, which permits testing intervals of up to ten years for valves in clean, non-fouling and noncorrosive services. PHMSA should also allow the use of self-calibrating instrumentation in lieu of costly field calibrations that may be subject to damage.

8. Incremental Costs of Integrating NFPA 59A-2023 references to hazardous fluid alongside references to LNG and natural gas throughout Part 193?

Question D.8:

What incremental, per-unit costs and benefits would arise from PHMSA integrating NFPA 59A–2023's references to 'hazardous fluid' alongside references to 'LNG' and 'natural gas' throughout part 193?

The Associations have concerns with the definition for hazardous fluid in NFPA 59A-2023. PHMSA should maintain the Part 193 definitions and keep hazardous fluids separate from LNG. PHMSA currently defines *hazardous fluid* as "gas or hazardous liquid" and *hazardous liquid* as "LNG or a liquid that is flammable or toxic."[94] The change in definition would add "ignitable," and "corrosive" and remove "flammable" from the definition. This expands the applicability of Part 193 to a much larger portion of the facility than it does currently. The 2001 edition also includes a reference to hazardous fluid lines that are under -20 degrees which extends the existing applicability.

[94] 49 CFR § 193.2007.

Integrating 'hazardous fluid' alongside LNG into Part 193 would also impact investigation and reporting requirements. While PHMSA should update the $10,000 property damage threshold in section 193.2515(a)(2) to reflect inflation, without such adjustment, cleanup costs for hazardous fluid spills can quickly exceed this amount—particularly when excavation of soil or gravel is required. This could result in companies being required to conduct expensive formal investigations for potentially minor spills. PHMSA should align the property damage threshold in section 193.2515 with the values used in Part 191.[95]

Another area of concern is section 193.2623, which addresses the inspection of LNG storage tanks. Hazardous fluid tanks are typically inspected under a facilities EPA-mandated Spill Prevention, Control, and Countermeasure (SPCC) plan. If the term "hazardous fluid" was included alongside LNG, section 193.2623 would impose additional inspection requirements on these tanks and could subject them to overlapping oversight by both EPA and PHMSA, without a corresponding improvement in safety outcomes.

9. Mobile or Temporary LNG Facilities

Question D.9:

What incremental, per-unit costs and benefits would arise in connection with the incorporation by reference in Part 193 of NFPA 59A–2023 (chapter 14) requirements governing ''mobile and temporary LNG facilities''?

Are there particular requirements in NFPA 59A– 2023 (chapter 14) that would entail noteworthy incremental, per-unit compliance costs and benefits?

PHMSA should assess whether existing mobile or temporary LNG equipment should be grandfathered upon the introduction of new design requirements.

10. Stationary Small-Scale LNG Facilities

Question D.10:

Are the criteria for ''stationary, small-scale LNG facilities'' in paragraph 17.1.2 of NFPA 59A–2023 appropriate?

What would be the incremental, per unit costs and benefits of adopting these provisions relative to current part 193 requirements (including referenced provisions in NFPA 59A–2001)?

Are there particular requirements in NFPA 59A–2023 pertinent to small-scale LNG facilities that would lead to incremental, per-unit costs and benefits?

NFPA 59A-2001 and Part 193 (as currently written) do not allow for less stringent requirements for small scale/peak shaver facilities. Some operators use mobile or temporary LNG facilities to

[95] Section 191.3 notes that the property damage threshold for natural gas incidents, including LNG, is set at $122,000 and increased each year for inflation. Effective July 1, 2025, the property damage threshold used for natural gas incident reporting will be $149,700. *See* https://www.phmsa.dot.gov/incident-reporting (last accessed on June 10, 2025).

support utility demand as they meet the exception criteria in NFPA 59A for less stringent siting and operating requirements that reflect their minimal hazard. These operators would like the option of building permanent installations which would increase the safety and reliability of these facilities yet use trailer-mounted equipment in most small-scale applications. It is impractical economically to build small permanent installations.

11. Installation of dikes around ASME-compliant single-walled containers and membrane containment tank systems

Question D.11:

What would be the incremental, per-unit costs and benefits to operators from installing dikes around American Society of Mechanical Engineers (ASME)-compliant single-walled containers and membrane-containment tank systems?

How many single-walled ASME containers, single-walled ASME vessels, and membrane-containment tank systems would different categories of LNG facilities have on average?

The Associations are concerned about the retroactive impact of such a modification on existing facilities. This proposal would be an impactful change. For instance, a single operator has hundreds of containers and tank systems that would be impacted. The estimated costs of this retroactive requirement applied to a facility is approximately $10 million. At a minimum, existing facilities should be grandfathered.

12. Design Spill Parameters for Pipe-in-Pipe Systems

Question D.12:

What are the incremental, per-unit costs and benefits to operators of different categories of LNG facilities from utilizing the design spill parameters for pipe-in-pipe systems in Frequently Asked Question (FAQ) #DS2(C) within PHMSA guidance for LNG facilities?

The Associations do not have comments in response to this question at this time.

13. Mechanical and Electrical Lockout Program

Question D.13:

What would be the initial and annual recurring incremental, per-unit costs and benefits to operators from generation and implementation of a robust mechanical and electrical lockout program in different categories of LNG facilities?

OSHA's Control of Hazardous Energy (lock/out tag/out) requirements[96] require the development and implementation of a mechanical and electrical lockout program. OSHA's requirements are inclusive of all forms of hazardous energy. The addition of a lockout program in 49 CFR Part 193

[96] 29 CFR § 1910.147.

would present regulatory duplication and potentially lead to conflicting or differing requirements and cost impacts. There would be no benefit to such duplication.

14. Interpretations

Question D.14:

Are there any PHMSA interpretations of its part 193 regulations whose safety value does not justify any associated compliance costs for each category of LNG facilities? If so, what are the associated compliance costs?

PHMSA should rescind PI-10-0026.[97] This interpretation states that, "for the determination of the property damage calculation, the cost of the damage to a vehicle striking a gas pipeline facility would normally be included in determining whether the incident was reportable." Yet, in PI-18-0016,[98] PHMSA clearly stated that the only property damage costs that need to be considered for reporting an incident are include labor, equipment, and materials in responding to and repairing a gas leak. Having both interpretations for reliance by PHMSA inspectors and operator personnel creates unnecessary confusion. PHMSA should rescind both interpretations.

If PHMSA were to incorporate paragraph 18.6.1.1, as discussed in the response to Question D.5, the agency should rescind PI-20-0012 (continuous monitoring).

PHMSA should also caution that some of the siting requirements in its existing FAQs were designed for marine export terminals and may not be appropriate for small-scale/peak shaver facilities.

Question D.14 (continued):

Are there any interpretations that merit codification in part 193 regulations?

PHMSA should codify PI-007-2012.[99] In that interpretation, the operator asked whether an increase in the unloading flow rate at an existing LNG facility would be considered a "significant alteration" under § 193.2051. PHMSA agreed that "because this operational change is within the original design parameters and the facility would not require any further modification, an increase in flow rate would not be a significant alteration and the siting requirements of § 193.2051 and Subpart B of Part 193 would not be triggered." PHMSA should codify this position in Part 193.

PHMSA should also codify FAQ H6 guidance which allows the use of FLACS.[100]

While not an interpretation, PHMSA should include its definitions of interstate and intrastate LNG facilities from its annual reporting instructions in Part 193.

---

[97] Letter of Interpretation to Jason Montoya, Bureau Chief, New Mexico Public Regulatory Comm'n, PI-10-0026 (June 14, 2011).
[98] Letter of Interpretation to Sean Mayo, Pipeline Safety Director, Washington Utilities and Transportation Comm'n, PI-18-0016 (Oct. 4, 2018).
[99] Letter of Interpretation to William Cope, Southern LNG Company, PI-007-2012 (Aug. 21, 2012).
[100] https://www.phmsa.dot.gov/pipeline/liquified-natural-gas/lng-plant-requirements-frequently-asked-questions#h6 (last accessed on June 24, 2025).

E. Adopting Newer Editions of Currently Incorporated Standards

1. Operator Approaches to Standards Currently Incorporated in Part 193 (Other than NFPA 59A-2001)

Question E.1:

Please describe current operator compliance strategies with respect to standards [identified by GAO as currently incorporated in Part 193 and meriting updating].

Do some or all operators generally comply with the older editions currently referenced in part 193 regulations, more recent editions, or both?

If operators comply with a more recent edition, which one— the latest edition or some intermediate edition? If some operators but not others comply with each of those updated standards, are there certain categories of LNG facilities that generally comply with more recent standards?

Operators of large-scale/baseload facilities adhere to the following standards which are currently incorporated in the regulations:

- American Gas Association, “Purging Principles and Practices,” 3rd edition, June 2001, (Purging Principles and Practices), IBR approved for §§ 193.2513(b) and (c), 193.2517, and 193.2615(a).
- API Standard 620, “Design and Construction of Large, Welded, Low-pressure Storage Tanks,” 11th edition, February 2008 (including addendum 1 (March 2009), addendum 2 (August 2010), and addendum 3 (March 2012)), (API Std 620), IBR approved for §§ 193.2101(b); 193.2321(b).
- ASCE/SEI 7-05, “Minimum Design Loads for Buildings and Other Structures” 2005 edition (including supplement No. 1 and Errata), (ASCE/SEI 7-05), IBR approved for § 193.2067(b).
- ASME Boiler & Pressure Vessel Code, Section VIII, Division 1: “Rules for Construction of Pressure Vessels,” 2007 edition, July 1, 2007, (ASME BPVC, Section VIII, Division 1), IBR approved for § 193.2321(a).
- GTI-04/0032 LNGFIRE3: “A Thermal Radiation Model for LNG Fires” March 2004, (GTI-04/0032 LNGFIRE3), IBR approved for § 193.2057(a).

Operators of large-scale/baseload LNG facilities do <u>not</u> utilize the following standards

- GRI-96/0396.5, “Evaluation of Mitigation Methods for Accidental LNG Releases, Volume 5: Using FEM3A for LNG Accident Consequence Analyses,” April 1997, (GRI-96/0396.5), IBR approved for § 193.2059(a).
- GTI-04/0049 “LNG Vapor Dispersion Prediction with the DEGADIS 2.1: Dense Gas Dispersion Model for LNG Vapor Dispersion,” April 2004, (GTI-04/0049), IBR approved for § 193.2059(a)
- FEM3A and DEGADIS 2.1 are not commonly used by operators for hazard modeling due to the limitations (unobstructed, level terrain, etc.). Operators utilize computational fluid dynamic (CFD) type models.

- Alternatives to LNGFIRE3. Industry uses LNGFIRE3 to model pool fire scenarios and develop thermal exclusion zones for hazardous fluid impounding areas. Per the requirements of Section 2.2.2.1 and 2.2.2.2 of NFPA 59A-2001, incorporated by reference in 49 CFR 193.2057, thermal radiation distances are calculated and confirmed to not extend past a property line that can be built upon. There have not been any more recent versions developed of LNGFIRE3 developed. If LNGFIRE3 provides results that need further refinement, other modeling software can be utilized which take into account the same physical factors (such as other computational fluid dynamic models). However, it must be validated by experimental test data and be subject to PHMSA's approval (49 CFR 193.2057(a)). Presently, industry has not yet received approval for an alternative to LNGFIRE3.

Large-scale/baseload LNG facilities use the latest version of ASME BPVC Section VIII, Division 1, based on the time of the project design, for design and construction of the vessels in order to receive a code stamp on the vessel itself. However, due to the outdated version incorporated into Part 193, industry is also required to follow the 2007 edition for pressure testing requirements. These pressure testing requirements differ from later editions, creating an increased compliance burden on industry. As discussed above, operators may need to adhere to more recent versions of NFPA 59A in working with FERC. *See* Response to Question D.1.d of these comments for additional discussion.

The Associations encourage PHMSA to move away from incorporating specific editions of standards. This approach forces PHMSA to always be behind as standards developing organizations update their materials at a faster pace than the agency can incorporate, leaving the agency relying on standards that have been superseded. For large-scale/baseload operators, PHMSA should adopt a risk-based regulatory approach consistent with section 110 of the PIPES Act in which operators are allowed to use the best standard that fits the facility's operations. OSHA and EPA have had success with a risk based safety management system/regulatory approach. In a risk-based approach, the selection and application of appropriate engineering, operating and maintenance activities is based upon the evaluation and analyses of appropriate internal and external standards, applicable codes, technical reports, guidance or recommended practices or documents of a similar nature. The process requires operators to comply with federal and state requirements, published consensus documents, and appropriate internal standards. Through this process operators are required to document, inspect and test in accordance with those identified requirements.

The Associations recognize that the National Technology Transfer and Advancement Act directs federal agencies to use voluntary consensus standards *in lieu of* government-written standards.[101] However, this proposal is not advocating for PHMSA to create its own standards and relies heavily on the use of consensus standards. Under a risk-based safety management system/regulatory

[101] Pub. L. No. 104-113, § 12(d) (the Act defines "technical standards" as "performance based or design specific technical specifications and related management systems"); OMB Circular A-119, § 2e (defines "voluntary consensus standards body" as an organization "that plans, develops, establishes, or coordinates voluntary consensus standards" using agreed upon procedures).

approach, each operator has the flexibility to use the most current version of a standard rather than waiting for PHMSA to incorporate it. Operators can determine which standard is best applied as part of that operator's safety management program. A risk-based approach is a useful as PHMSA is tasked with applying standards to a diverse set of LNG facilities.

2. Appropriate Edition of Existing Standards Incorporated in Part 193

Question E.2:

To which edition of each standard should PHMSA update its part 193 regulations?

Please provide technical, safety, and economic reasons for updating part 193 regulations to reference a particular edition of each standard

As stated under E.1, the Associations encourage PHMSA to move away from incorporating specific editions of standards. Large-scale LNG facilities should be provided with a risk-based regulation as outlined in section 110 of the PIPES Act, eliminating the need to specify a standard and edition of such standard within the regulation.

The Associations provide the following list of the editions of standards that PHMSA should incorporate.

Current IBR standard within § 193.2013	Recommended Version
American Gas Association, "Purging Principles and Practices," 3rd edition, June 2001	AGA "Purging Manual" – 4th Edition, September 2018 ** name changed with the 2018 revision
API Standard 620, 11th edition, February 2008	API Standard 620, 12th edition, October 2013
ASME Boiler & Pressure Vessel Code, Section VIII, Division 1: 2007 edition	ASME Boiler & Pressure Vessel Code, Section VIII, Division 1, 2023 edition

Large-scale/baseload LNG facilities follow the 3rd edition of AGA Purging Principles and Practices (June 2001) in compliance with Part 193. There would not be any significant technical, safety, or economic concerns with updating the edition listed in the CFR because the document is a best practices manual.

Large-scale/baseload LNG facilities follow the 11th edition of API Standard 620 with addenda 1, 2, and 3 because 49 CFR 193 requires it. The latest edition provides improved design and construction methodologies that would likely lead to improved equipment reliability (i.e. testing, vessel construction etc.).

ASME has updated its Boiler & Pressure Vessel Code (ASME BPVC) in the subsequent versions published since 2007. PHMSA should update 49 CFR 193 to reference to the latest edition in order to be consistent with recognized acceptable vessel manufacturing and testing. The updated editions provide an equal if not greater level of safety for the design and construction of boiler and pressure vessels.

Regarding modeling software, DEGADIS is a two-dimensional software that does not take into account elevation changes, plant geometry, etc. and therefore is not utilized for hazard modeling. Instead, industry uses Phast 6.6, 6.7 and 8.4 which was approved by PHMSA in 2011 and 2021, respectively, and FLACS, which was approved by PHMSA in 2011 (PHMSA FAQ H6). PHMSA should consider updating Part 193 regulations to reflect the PHMSA FAQ H6 guidance.

LNGFIRE3 is only applicable for pool fire scenarios. It was developed for square, rectangular, or circular geometries only and cannot be used to model irregular shapes. Additionally, it can only be used on computers using a Windows-8 operating system and is no longer supported by its developers which means there is no technical support and the software is more vulnerable from a cyber-security standpoint. LNGFIRE3 is utilized for all hazardous fluids, including non-LNG. It should be noted that, given the different burning properties of fuels heavier than LNG, results obtained using LNGFIRE3 for non-LNG fires are considered highly conservative. PHMSA should consider approving additional models and methods for modeling pool fire scenarios for all hazardous fluids (including non-LNG). This has potential cost savings in the form of reducing land usage (via unnecessarily conservative equipment spacing, unnecessary passive protection, and unnecessary exclusion zones).

PHMSA should consider including hazardous modeling refinement through computational fluid dynamics (such as FDS or KFX) in this rulemaking. The inability to refine overly conservative hazard modeling results in a higher economic burden on operators (requiring larger exclusion zones, additional hazard mitigation, etc.).

3. Incremental, Per-Unit Costs and Benefits of Incorporating Newer Editions

Question E.3:

Please estimate any incremental, per-unit costs and benefits that would arise from updating each of those standards to a more recent standard.

Are there particular provisions of those standards that entail noteworthy incremental costs and benefits?

The incorporation by reference of older standards can impose a higher economic burden on the industry (as discussed in D.1). Implementation of a risk-based regulation would result in flexibility for LNG plants to design according to best practices as opposed to an overly conservative "catch-all."

4. Exclusion of Specific Provisions in More Recent Editions

> **Question E.4:**
>
> Are there specific provisions or sections in those updated editions that PHMSA should exclude when incorporating those standards by reference with respect to some or all part 193-regulated LNG facilities? Please provide the technical, safety, and economic reasons for such an exclusion.

As stated under E.1, the Associations encourage PHMSA to move away from incorporating specific editions of standards. Large-scale LNG facilities should be provided with a risk-based regulatory approach as outlined in section 110 of the PIPES Act, eliminating the need to specify a standard and edition of such standard within the regulation.

The Associations will evaluate this question and may provide additional comments at a later date.

5. Standards Updates in Development

> **Question E.5:**
>
> Are there any updates in development for consensus industry standards currently incorporated by reference in part 193 regulations that could merit inclusion in this rulemaking?
>
> Please provide the technical, safety, and economic reasons for inclusion of those forthcoming updates.?

While standards developing organizations are currently developing new editions of various industry consensus standards incorporated by reference in Part 193, the Associations cannot comment on whether these editions should be incorporated by reference at this time. The development process is complex and all stakeholders should wait until the process is complete prior to analyzing whether there is technical, safety, and economic support for incorporating by reference.

F. Incorporated Standards for the First Time

1. New Standards that Should Be Incorporated

> **Question F.1:**
>
> Are there any consensus industry standards pertinent to part 193- regulated LNG facilities that PHMSA should consider incorporating by reference for the first time?
>
> Please identify any such standards, noting the edition to be incorporated by reference and any portions of those standards that should be excluded from such incorporation, along with any technical, safety, and economic justification.

PHMSA should consider incorporating API RP 754 (Process Safety Performance Indicators for the Refining and Petrochemical Industries) as an alternative in lieu of the current requirements of 49 CFR § 193.2515.

PHMSA should consider referencing API RP 576 in sections 193.2619(c) and (d). API RP 576-2024, section 6.9.1, states if a risk-based inspection (RBI) assessment is not utilized to establish a longer interval, 5 years (for typical process services) and 10 years (for clean (non-fouling) and non-corrosive services), are typical maintenance inspection and testing frequencies for pressure relief devices. By comparison, sections 193.2619(c) and (d) include a prescriptive requirement of testing once each calendar year, not to exceed 15 months. Instead, PHMSA should incorporate API RP 576-2024, section 6.9.1.

PHMSA should also consider referencing standards such as API 625 and API 620 for tank design and construction, particularly where these are already referenced in NFPA 59A-2023. Incorporating these standards directly into Part 193 would reduce ambiguity, address known gaps in the current regulatory framework, and ensure consistency.

While the Associations urge PHMSA to create a risk-based approach for large scale operators consistent with section 110 of the PIPES Act and allow a similar option for small-scale and peak shavers, if the agency is required to amend Part 193 and incorporate new standards to support this effort, the Associations recommend the incorporation of AP 510, API 570, API RP 576, API 579, API 580, and API 581.

2. Sections of Part 193 that Should Reference New Standards

Question F.2:
Which provisions of part 193 should reference these standards?

See response to F.1.

3. Incremental, Per-Unit Costs and Benefits from Incorporating New Standards

Question F.3:
Please estimate any incremental, per-unit costs and benefits that would arise from incorporating by reference [the new] standard. Are there particular provisions of those standards that entail noteworthy incremental costs and benefits?

Large-scale/baseload LNG facilities could see an annual cost benefit of $2,500,000 - $3,000,000[102] or more if sections 193.2619(c) and (d) are revised to allow risk-based scheduling for pressure safety valve testing. The majority, more than 90%, of a typical LNG Plant pressure safety valves are in clean service and could be evaluated for testing once every 10 years per API RP 576-2024, section 6.9.1. Moving to a longer inspection interval would enhance safety since excessive testing of control systems introduces additional risk. Pressure-relieving devices and valves are precision

[102] This cost-benefit estimate is derived from the approximate cost for qualified inspectors to inspect, test, and create subsequent records for an LNG Plant (*i.e.,* nine "trains" and the associated LNG Plant auxiliary assets) in 2024. This cost-benefit does not include the costs savings created by a reduction in administrative tasks such as safe work permitting, operator car seal removal and application, operator valve tasks, and maintenance costs associated with required outages for test completion.

components that should be handled with care to help ensure there is no degradation of the tolerances of the equipment. Introducing excessive and unnecessary testing based on a prescriptive regulation increases the handling of, wear on, and risks associated with isolation, testing, removal, and re-installation of equipment.

49 CFR § 193.2619(c)(2) requires testing control systems intended for fire protection at a six-month interval that does not necessarily align with the various NFPA standards. Testing could be reduced to align with various NFPA standards, such as NFPA 72 table 14.4.3.2 for gas detectors, which would move testing from a 6-month interval to an annual frequency. Large-scale/baseload LNG-facilities could see an annual cost benefit of approximately $600,000- $750,000 or more if 49 CFR § 193.2619(c)(2) is revised to remove the six-month interval for fire and gas detection equipment.[103]

Large-scale/baseload LNG facilities need to take maintenance outages to perform the 49 CFR 193.2619(c)(2) requirements. Large-scale/baseload LNG facilities could see a benefit of $400,000-500,000 a year in fire and gas equipment specialist labor costs associated with the outage. These outages cost a large-scale 9 train platform approximately $13,500,000 each year in production loss.

Operators should be allowed to align inspection intervals with actual risk, reducing unnecessary testing and associated costs. For example, operators could avoid redundant inspections of clean service valves and instead focus resources on higher-risk components. This would improve safety outcomes while reducing operational burden.

Large-scale/baseload LNG facilities could see an annual cost-benefit of approximately $3,000,000 or more if PHMSA revised 49 CFR 193.2635(d) in line with API Standards 570 and 580.[104]

---

[103] This cost benefit is derived from the approximate cost for qualified inspectors to inspect , test, and create subsequent records for an LNG Plant (i.e. nine "Trains" and the associated LNG Plant auxiliary assets) in 2024. This cost benefit does not include the savings created by a reduction in maintenance costs due to administrative tasks such as safe work permitting, and scaffolding.

[104] This cost-benefit is derived from the approximate cost for API qualified inspectors to inspect and create subsequent records for an LNG Plant (i.e. nine "trains" and the associated LNG Plant auxiliary assets) in 2024. This benefit is provided to operators who would follow API 570-2024, section 6.3.3 for Class 1, 2, 3, 4 and injection point piping circuits and do not utilize RBI. The cost savings occurs as the rate for Class 1 and 2 is spread over a five-year interval, Class 3 and 4- although 4 is optional- inspections are spread over a ten-year interval in lieu of the PHMSA prescribed three-year interval. The cost benefits would increase with the use of a RBI methodology in API 580 and evaluation of those assets covered under API 510 and 570. This cost benefit does not include the costs savings created by a reduction in administrative tasks such as safe work permitting, scaffolding, or insulation removal and re-application.

G. Risk-Based Approach for Large-Scale/Baseload LNG Facilities

1. Appropriate Metric and Threshold for Identifying a Large-Scale LNG Facility

Question G.1:

Section 110 of the PIPES Act of 2020 requires PHMSA to update part 193 operating and maintenance standards for ‘‘large-scale’’ LNG facilities (other than peak shaving facilities) to provide for a ‘‘risk-based regulatory approach’’ that PHMSA ensures will achieve an equivalent level of safety to current, prescriptive part 193 operating and maintenance standards.

What is the appropriate metric and threshold for determining whether an LNG facility is a large-scale LNG facility and why is it appropriate?

As discussed above, the Associations support the use of the following definition of large-scale facilities and the use of a risk-based inspection process, as directed by Congress:

> *Large-Scale/Baseload LNG Facility.* A plant that operates throughout the year to provide gas supply and exceeds the limitations of a small-scale/peak shaver LNG facility

The operations,[105] geographical size (footprint),[106] process complexity,[107] storage capacity,[108] transfer systems and intended use of produced LNG (international consumption)[109] of a large-scale/baseload facility makes it distinguishable from small-scale/peak shavers, satellite and mobile and temporary facilities. These characteristics distinguish large-scale LNG facilities from other types of LNG facilities. For all of these reasons, the risk profile of large-scale/baseload LNG facilities vastly differs from other types of LNG Facilities existing within the United States.

---

[105] Large-scale/baseload LNG facilities operate nearly continuously, only ceasing production for short durations to perform required/needed maintenance.

[106] Large-scale/baseload LNG facilities generally have a large geographical footprint ranging from 100's of acres to 1000 acres plus.

[107] Large-scale/baseload LNG facilities generally consist of multiple processing units (Trains), containing extensive piping, controls and prime movers (compressors, pumps etc.), ancillary material storage and processing units. Large-scale/baseload LNG facilities are highly instrumented with complex control schemes and instrumentation.

[108] Large-scale/baseload LNG facilities generally have extensive storage capacity consisting of multiple large LNG storage tanks containing millions of barrels of LNG.

[109] Large-scale/baseload LNG facilities are engaged in the international transportation of LNG, either importing or exporting LNG via ocean-going LNG vessels. Although large-scale/baseload LNG facilities may have surface transportation loading facilities (truck/rail) for domestic consumption their primary mode of LNG transfer is via a Marine Transfer Area for international transportation and product use internationally.

2. Implementation of Risk-Based Approach into Operations and Maintenance Requirements

Question G.2:
For which provisions of part 193, subparts F (Operations) and G (Maintenance) should a risk-based regulatory approach provide an alternative? What would be the incremental, per-unit cost benefits from substitution of a risk-based regulatory approach, estimated for each of those part 193, subparts F and G provisions?

Consistent with section 110 of the PIPES Act, PHMSA should create a risk-based approach for all provisions in Subparts F and G for large-scale/baseload operators. Small-scale/peak shaver operators should also have the opportunity to use a risk-based approach for all operation and maintenance activities, if those operators can accommodate such an approach. Alternatively, those operators who choose not to pursue a risk-based approach can comply with Part 193 and the standards incorporated by reference.

When designing this program, PHMSA should create a hybrid program for small-scale/peak shaver, satellite, and mobile or temporary LNG facilities where the default position is to follow Part 193 unless the operator notifies the agency that it is participating in a risk-based program. As the operator hits milestones in the schedule, as outlined in the implementation plan required under section 110(d) of the PIPES Act, it would notify PHMSA. The notification would be similar to a construction notification in section 191.22. PHMSA should adopt a methodology using the elements of section 110(c)(1)-(14) of the PIPES Act. While the Associations acknowledge that PHMSA preempts OSHA's regulations where there are overlaps,[110] OSHA's process safety management (PSM) program is a proven method. PHMSA should use it as a model to develop the mandated risk-based approach elements in section 110 of the PIPES Act. PSM was created in the 1990s, at least a decade after Part 193 was first codified. It has proven to be an effective framework for the petrochemical industry. LNG facilities under FERC jurisdiction comply with elements of OSHA PSM (29 CFR § 1910.119) as part of the FERC project progression process. Operators report on PSM elements on a semi-annual basis as part of periodic reporting, and/or annually as pre-inspection material as required by the environmental conditions of the authorizing order. Large-scale LNG facilities provide FERC with 29 CFR 1910.119(d) process safety information, 29 CFR 1910.119(e) process hazard analysis, 29 CFR 1910.119(f) operating procedures, 29 CFR 1910.119(h) contractor management information, 29 CFR 1910.119(j) mechanical integrity information, 29 CFR 1910.119(l) management of change information, 29 CFR 1910.119(m) incident investigation information, and 29 CFR 1191.119(n) emergency planning and response information.

Switching to a risk-based approach would result in significant cost savings from a staffing perspective to support and respond to compliance inspection tasks. One large-facility/baseload

[110] The Occupational Safety and Health Act expressly provides that where Congress has granted other federal agencies the authority to regulate specific working conditions, OSHA's regulations are preempted. *See* 29 U.S.C. § 653(b)(1). In the pipeline safety context, courts have previously found that PHMSA regulations preempt OSHA regulations (*Columbia Gas of Pennsylvania, Inc. v. Marshall*, 636 F.2d 913, 915-919 (3rd Cir. 1980)) and OSHA published a 2021 interpretation that found the PSM requirements were preempted and did not apply at LNG facilities subject to Part 193.

operator estimated that it would save $4 million annually solely on personnel costs.[111] Many compliance inspection tasks involve a facility shutdown so moving to a risk-based approach would result in a separate cost savings of $3 million per year for one large-scale/baseload facility. Moving to a risk-based approach would also create savings for PHMSA's inspection program. In 2024, PHMSA estimated that it costs the federal government $1,076,300 per year[112] to conduct LNG recordkeeping inspections. It was not clear whether the reference to the federal government included other agencies' personnel.

3. Use of Consensus Standards or Industry Standards or Protocols

Question G.3:

Are there particular regulatory or conceptual frameworks or consensus industry standards or protocols that are appropriate for use in designing implementation plans for an alternative risk-based regulatory approach?

Are those frameworks or consensus industry standards or protocols employed by ''large-scale LNG facilities—and if so, how widely?

Are such frameworks or standards employed voluntarily or pursuant to legal requirements (e.g., the terms and conditions of a FERC certificate of convenience and necessity)?

Please provide technical and safety reasons (to include pertinent data or studies) for the appropriateness of those frameworks or industry standards.

The Associations recommend using section 110(c)(1)-(14) elements of the PIPES Act to create a framework for designing an implementation plan of a risk-based regulatory approach. Implementation plans should require, for those elements under section 110 of the PIPES Act, an anticipated schedule for implementation and an overview of the process as outlined in section 110(d) of the PIPES Act. PHMSA should utilize the current structure of the IA questionnaire in reviewing the implementation plans and should create questions to guide Operators in the development of their plans. PHMSA should review those implementation plans based on their statutory authority.

The Associations recommend the use of API Recommended Practice 580 (Elements of a Risk-Based Inspection Program), API Recommended Practice 576 (Inspection of Pressure-relieving Devices), API 510 (Pressure Vessel Inspection Code), and API 570 (Piping Inspection Code) in developing a risk-based regulatory approach for large-scale operators. Inclusion of these standards would align with the petrochemical industry. Large-scale LNG facilities use API Recommended Practice 580, API 510, and API 570 in developing maintenance and inspection programs.

---

111 This estimate was calculated by using an average of 10,000 compliance inspections per year over a 5-year period, a total of 4 manhours (on average) to complete each compliance inspection, and an average of $100 per hour for personnel costs.

112 In a 2024 application to OMB for renewal approval of existing recordkeeping requirements for LNG operators, PHMSA estimated that the cost of conducting these inspections was approximately $1,076,300 per year. *See* OMB Control No. 2137-0048, Supporting Statement (Feb. 26, 2024). The agency calculated this figure based on 100 federal inspectors and an average salary of $107,630.

4. Relationship Between LNG Facility Implementation Plan and Emergency Response Plan Required Under the Natural Gas Act

Question G.4:

What should be the relationship between an LNG facility implementation plan and the Emergency Response Plan required under section 3(a) of the Natural Gas Act (15 U.S.C. 717b–1)?

There should be no relationship between a LNG facility implementation plan and the Emergency Response Plan required under section 3(a) of the Natural Gas Act (15 U.S.C. § 717b–1). Emergency Procedures are required per 49 CFR 193.2509 and are reviewed by PHMSA during inspections. Approval of an Emergency Response Plan by PHMSA is not required under section 3(a) of the Natural Gas Act (15 U.S.C. § 717b–1). Emergency Response Plans are required to be submitted to FERC as a submittal for compliance with the relevant environmental condition to gain approval to advance a project to the phase of "site preparation." Emergency Response Plans at this phase of a project in practicality are largely the responsibility of the engineering, procurement, and construction contractor. Incorporating the FERC Emergency Response Plan as a part of a PHMSA LNG Facility Implementation Plan is duplicative and unnecessary and would introduce duplicative and additional burdens on industry.

5. Required Content of LNG Facility Implementation Plan

Question G.5:

What should be the required content and information in LNG facility implementation plans submitted to PHMSA? What would be the incremental, per-unit unit cost for development of implementation plans?

PHMSA should follow section 110(d)(2) of the PIPES Act of 2020 in designing an implementation plan. As directed by statute, the plan should only include "an anticipated schedule for the implementation of the requirements described in section (c) and an overview of the process for implementation."[113] In compliance with the "Ensuring Lawful Governance and Implementing the President's "Department of Government Efficiency" Deregulatory Initiative," Executive Order PHMSA should not add elements to the implementation plan that do not exist in section 110(d).[114]

[113] PIPES Act of 2020, § 110(d) (Dec. 27, 2020).

[114] Section 2 of the Ensuring Lawful Governance and Implementing the President's "Department of Government Efficiency" Deregulatory Initiative," Executive Order provides that agencies must identify regulations that are "based on anything other than the best reading of the underlying statutory authority or prohibition." On this basis, PHMSA should not create new regulations that are based on the best reading of the statute. Exec. Order No. 14,219, "Ensuring Lawful Governance and Implementing the President's 'Department of Government Efficiency's Deregulatory Initiative," 90 Fed. Reg. 10,583(Feb. 25, 2025).

6. Annual, Incremental, Per-Unit Costs for Execution of Implementation Plans

Question G.6:

What would be the annual incremental, per-unit costs for operators' execution of implementation plans? Please provide such an estimate for each of the elements (e.g., employee and contractor training; quality assurance programs) listed in section 110(c).

Most, if not all, large-scale/baseload operators are already submitting the data listed in section 110(c) to FERC. Therefore, the costs should not be substantial. If provided an opportunity to adopt a risk-based regulation, there would be costs associated for small-scale/peak shaver, satellite, and mobile or temporary LNG facilities not under FERC jurisdiction.

7. Processes to Review Implementation Plans

Question G.7:

What processes should PHMSA employ in reviewing and evaluating operator submissions? Are there models for those processes elsewhere in current PHMSA regulations? If so, how are those models appropriate for use in connection with LNG facility implementation plans? Are there elements of those models that would be inappropriate for use in connection with LNG facility implementation plans?

Section 110(d) of the PIPES Act is limited to developing an overview and schedule. PHMSA should review the implementation plans based on its statutory authority.

PHMSA may want to use the National Center of Excellence for LNG Safety to develop best practices for inspecting a risk-based approach across large-scale and small-scale,/peak shaver facilities.[115] PHMSA should also consider updating the Inspection Assistant question set to incorporate the review of the implementation plan for items listed in section 110(c)(1-14) of the PIPES Act of 2020. Questions should include a review of the proposed process and resulting record(s). Questions should focus on confirming documentation of the program elements and how the elements of the program are implemented and a description of the source's records documenting compliance with the associated element. PHMSA's questions should be consistent with the agency's statutory authority.

PHMSA requested information on models used for similar processes. The Associations are not aware of any models, but would suggest the creation of a secure Inspection Assistant portal that also provides the status of PHMSA's review to the operator.

[115] Congress directed PHMSA to establish a National Center of Excellence for LNG to "further the expertise of the federal government in the operations, maintenance, and regulatory practices of LNG facilities, act as a repository of information on best practices for the operation of LNG facilities, and facilitate collaboration among LNG sector stakeholders." *See* section 111 of the PIPES Act of 2020.

8. Factors to Inform PHMSA's Review of Implementation Plans

Question G.8:
What factors should inform PHMSA's review of LNG facility implementation plans?

PHMSA's statutory authority should be the leading factor in informing the review of facility implementation plans.

H. Application of Executive Orders

1. Burdensome Regulations

Question H.1:
Are there current aspects of PHMSA regulations that are particularly burdensome on the ability of industry to operate LNG facilities that PHMSA should consider amending or rescinding?

a. Monitoring Operations

The Associations are concerned with section 193.2507 (Monitoring Operations).[116] That regulation provides that "[m]onitoring must be accompanied by watching or *listening from an attended control center* for warning alarms, such as gas, temperature, pressure, vacuum, and flow alarms, or by conducting an inspection or test at intervals specified in the operating procedures."[117] By comparison, section 18.6.1.1 of NFPA 59A-2023 allows operating personnel to leave the control room to perform scheduled field inspections or to address other issues in the field.

b. Annual Capacity Test on UPS Battery System

Under 49 CFR 193.2613, auxiliary power sources must undergo an annual capacity test. Although an Uninterruptible Power Supply (UPS) is not designed for extended operation, it may qualify as an auxiliary power system in specific applications. Conducting annual capacity tests on UPS systems is not advisable, as such testing could diminish the battery's lifespan. PHMSA should amend this regulation to require a load test that aligns with the manufacturer's guidelines of the UPS system.

c. Continuous Attendance

As discussed in response to Question D.5, section 193.2441(c) requires that "each control center have personnel in *continuous attendance* while any of the components its control are in operation, unless control is performed from another control center that also has personnel in continuous attendance."[118] This creates a burden for facilities operating with a single control room operator. This is an issue because particularly for peak shavers, single staffing occurs during boil-off periods and not during liquefaction or gasification activities. Requiring two individuals for inspections may impose unnecessary costs with minimal, if any, additional safety benefit. Revising section

[116] 49 CFR § 193.2507.
[117] *Id.*
[118] 49 CFR 193.2441(c).

193.2441(c) would produce a cost savings of approximately $540,000 - $700,000 per year for each one person-controlled facility.[119]

By comparison, section 18.6.1.1 of NFPA 59A (2023) provides in its Control Center section that "[a]t plants with onsite control centers, operating personnel shall be permitted to leave the control room to perform field inspections or to address activities in the field related to the plant's operation."[120] PHMSA should incorporate this section of NFPA 59A-2023 regarding control room attendance or, alternatively, allow the use of technology with control center capabilities. These changes would not impact safety but remove unnecessary personnel costs. The additional costs of hiring and maintaining additional personnel at these facilities for the sole purpose of establishing "continuous attendance" are not justified.

2. Necessary Regulatory Additions

Question H.2:

Are there areas that PHMSA could add regulatory text that would reduce costs on operators without reducing safety outcomes?

a. Power Generation Facilities

PHMSA should confirm that power generation facilities that are co-located with an LNG facility are not a LNG facility within the meaning of 49 CFR § 193.2007, and are therefore not subject to the design and construction provisions of 49 CFR Part 193. A 2007 PHMSA interpretation addressing Part 192 makes clear that an electric power plant is not considered part of a pipeline facility. The interpretation addressed the "jurisdictional end-point of a lateral pipeline running from a transmission pipeline to an electrical power plant" and clarified that the power plant was not a pipeline facility.[121] Moreover, interpretations of the scope of Part 193 regulations issued by PHMSA suggest that a direct link to LNG operations is required for a facility to be considered part of the LNG facility. For example, PHMSA found that a natural gas liquids (NGL) recovery process was not part of a small-scale LNG facility where the NGL plant was integrated with LNG production and cryogenic vapors from the NGL plant were used in the LNG liquefaction process. Only the "LNG Plant" was subject to Part 193.[122] PHMSA found that a building that would "house five LNG plant personnel and serve as a gas/electric meter maintenance shop" was not part of the LNG facility because its proposed use lacked a sufficient connection to the LNG process.[123]

Neither the legislative history of the PSA nor the regulatory history of Part 193 contains any indication that either Congress or PHMSA considered an electric power plant as part of an LNG facility or a pipeline facility, or that they intended for the pipeline safety requirements to extend to a power plant associated with or on the same site as an LNG facility. On the contrary, PHMSA

[119] This figure was calculated by using the two employees at each control center and including overtime and benefits. It does not include any technological resolution.
[120] Section 18.6.1.1, NFPA 59A (2023).
[121] CPN Pipeline Co., PI-07-0025 (Feb. 5, 2007).
[122] Linde Engineering North America, PI-16-0010 (Apr. 9, 2019).
[123] Northern States Power Co., PI-84-0102 (June 1, 1984).

amended its Part 193 regulations in 2000 to eliminate the reference to "power facilities" in 49 CFR § 193.2051.[124]

Nevertheless, there is the potential for confusion in the regulation by PHMSA of LNG facilities that employ stand-alone on-site power generation facilities whose sole purpose is to provide electric power to the LNG facility. In other words, the mere fact that power generating facilities are co-located with and situated inside the protective berm or fencing that surrounds an LNG facility, may lead to a presumption that such facilities should be subject to Part 193. To be clear, electric generating facilities that are co-located at an LNG facility are not used either to transport or treat gas during the course of transportation, nor are they used in the transportation of gas or in the treatment of gas in the course of transportation. In addition, an electric generating facility does not store gas. Such electric generating facilities do not meet the definition of LNG facility under the PSA. Power plants that are co-located at LNG facilities consist of combustion gas turbine generators and steam turbine generators which generate electricity for consumption at the respective LNG export terminals, instead of the LNG facility relying on electric power supplied by the grid. Such power plants are distinct from the terminal transportation facilities, which consist of the natural gas pre-treatment, liquefaction, storage, and transfer facilities.

U.S. power plants are routinely designed and constructed to satisfy design standards developed by the American Society of Civil Engineers ("ASCE") – in particular, ASCE 7-10 – and the American Society of Mechanical Engineers ("ASME") – in particular ASME B31.1. The ASME and ASCE standards applicable to power plants have even been incorporated and referenced in broadly applicable building codes and safety standards. For example, the current Louisiana Building Code has adopted International Building Code 2015, which utilizes ASCE 7-10 as its reference standard for power plants.[125] Similarly, NFPA 59A provides that "Power plant piping shall be in accordance with ASME B31.1, *Power Plant Piping.*"[126]

In contrast, 49 CFR § 193 and NFPA 59A-2001 apply different engineering design standards and codes applicable to processing plants such as LNG facilities. As such, even if a builder of a power plant wanted to apply the design standards set forth in Part 193 to its facility, it would be practically difficult to do so and would also raise safety concerns. Among other conflicts between Part 193 and accepted power plant design standards, NFPA 59A-2001 requires that piping systems in processing plants such as LNG facilities be designed in accordance with ASME B31.3 – not ASME B31.1. ASME B31.3 minimum design requirements assume a shorter life of service than ASME B31.1, apply lower safety factors than ASME B31.1, and permit higher allowable material stress factors than ASME B31.1.

Power generation equipment commercially available for utility, independent power and industrial applications is not (and never has been) designed in accordance with ASME B31.3 by manufacturers of such major components, such as heat recovery steam generators and industrial-

---

[124] Specifically, the 2000 version of the Part 193 regulations eliminated "normal or auxiliary power facilities" from the scope of LNG facilities to which the safety design requirements apply. *Compare* 65 Fed. Reg. 10,958 (Mar. 1, 2000) *with* 45 Fed. Reg. 9,184 (Feb. 11, 1980).

[125] *See* IBC 2015 – Chapter 35.

[126] *See* Section 10.2.1.4.

size gas and steam turbines. In addition, we are unaware of any relevant state or local building codes that accept ASME B31.3 for permitting power generation equipment or utility scale power generation facilities.

Neither the PSA nor Part 193 provides any guidance as to how to reconcile these engineering design differences, or otherwise explains how a power plant could simultaneously comply with state building codes and lower design requirements applicable to LNG facilities.

PHMSA should confirm that power generation facilities that are co-located with an LNG facility or within an LNG Plant are not an LNG facility within the meaning of 49 CFR § 193.2007, and are therefore not subject to the design and construction provisions of 49 CFR Part 193. PHMSA should also amend section 193.2001(b)(1) to reflect that Part 193 does not apply to utility power generation facilities.

b. PHAST Modeling

The Associations recommend allowing the use of PHAST modeling for pool fires. Part 193 allows the use of LNG FIRE3 or alternate technologies with the Administrator's approval. PHAST is used frequently in LNG facility design and should be allowed as a default choice. LNGFIRE3 was initially incorporated by reference in 2000 and is an outdated software program.

c. Tank Settlement Survey

PHMSA should incorporate the LNG Tank settlement survey requirements specified in Section 18.6.2.2 of NFPA 59A-2023 into 49 CFR 193.2623(a). Once an LNG tank has been in service for a period, its settlement behavior becomes predictable. Annual surveys tend to yield limited data for the cost involved.

3. Outdated or Unnecessary Regulations

Question H.3:

Which aspects of current PHMSA regulations do operators find outdated or unnecessary because industry practice or existing industry guidelines are an equivalent or better standard both for cost savings and safety outcomes?

The Associations reference their comments in section H.1.c (Continuous Attendance) in response to this question.

PHMSA should add language to remove prescriptive frequencies within the regulation to comply with section 110 of PIPES Act of 2020. In particular, Subpart G-Maintenance, includes prescriptive regulatory requirements that are not consistent with a risk-based approach. As stated in 49 CFR 193.2503(a), "Each operator shall determine and perform, consistent with generally accepted engineering practice, the periodic inspections or tests needed to meet the applicable requirements of this subpart." However, in 49 CFR §§ 193.2613, 193.2619, 193.2621, and 193.2635 the regulation specifies the frequency at which maintenance must be performed.

PHMSA should incorporate the relief valve testing requirements outlined in Section 18.10.7 of NFPA 59A-2023 to align with established technical standards, such as API RP 576, and to reflect best practices observed in other industries. Sections 193.2619(c) and (d), control systems are tested on an annual basis that otherwise would be tested on a risk-based profile such as outlined in API RP 576. API RP 576-2024, section 6.9.1, states if an RBI assessment is not utilized to establish a longer intervals, that 5 years for typical process services and 10 years for clean (non-fouling) and non-corrosive services, are typical maintenance inspection and testing frequencies for pressure relief devices. Large-scale LNG facilities could see an annual cost benefit of $2,500,000 - $3,000,000 or more[127] if 193.2619(c) and (d) is revised to allow risk based scheduling for pressure safety valve (PSV) testing. The majority, more than 90%, of a typical LNG facility PSV's are in clean service and could be evaluated for testing once every 10 years per API RP 576-2024, section 6.9.1 (if not using a risk-based inspection program). At one large-scale/baseload facility, in the past 18 months, out of ~1,500 PSVs tested, none of the 1,500 were documented to have an issue with the as found condition before any adjustments. PHMSA should incorporate relief valve testing requirements to align with established technical standards, such as API RP 576, and to reflect best practices observed in other industries.

Section 193.2619(c)(2) should be revised to remove the 6-month interval for fire and gas detection equipment. Large-scale/baseload LNG facilities could see a benefit of $100,000- $125,000 or more[128] if 49 CFR 193.2619(c)(2) is revised to remove the 6-month interval for fire and gas related PSV testing; and testing was performed annually. Large-scale LNG facilities need to take maintenance outages to perform the 6M PM's required by 49 CFR 193.2619(c)(2). Large-scale/baseload LNG facilities could see a benefit of $400,000-500,000 a year in fire and gas equipment specialist labor costs associated with the outage. These outages cost a large-scale 9 train platform approximately $13,500,000 each year in production loss.

Large-scale/baseload LNG facilities could see an annual cost benefit of approximately $3,000,000 or more[129] if 49 CFR 193.2635(d) was revised in line with API Standards 510, 570, and 580. This benefit is provided to operators who would follow API 570-2024, section 6.3.3 for Class 1, 2, 3, 4 and injection point piping circuits and do not utilize RBI. The cost savings occurs as the rate for Class 1 and 2 is spread over a five year interval, Class 3 and 4- although 4 is optional- inspections

---

[127] This cost benefit is derived from the approximate cost for qualified inspectors to inspect, test, and create subsequent records for an LNG Plant (i.e. nine "Trains" and the associated LNG Plant auxiliary assets) in 2024. This cost benefit does not include the costs savings provided by a reduction in administrative tasks such as safe work permitting, operator car seal removal and application, operator valve tasks, and maintenance costs associated with required outages for test completion.

[128] This cost benefit is derived from the approximate cost for qualified inspectors to inspect , test, and create subsequent records for an LNG Plant (i.e. nine "Trains" and the associated LNG Plant auxiliary assets) in 2024. This cost benefit does not include the cost savings provided by a reduction in maintenance costs due to administrative tasks such as safe work permitting, and scaffolding.

[129] This cost benefit is derived from the approximate cost for API qualified inspectors to inspect and create subsequent records for an LNG Plant (i.e. nine "Trains" and the associated LNG Plant auxiliary assets) in 2024. This cost benefit does not include the cost savings provided by a reduction in administrative tasks such as safe work permitting, scaffolding, or insulation removal and re-application.

are spread over a ten-year interval in lieu of the PHMSA prescribed three-year interval. The cost benefits would increase with the use of a Risk-Based Inspection (RBI) methodology detailed in API 580 and evaluation of those assets covered under API 510 and 570.

As discussed in D.1, the Associations also recommend that PHMSA clarify that vacuum jacketed piping or pipe in piping systems rated for temperature and pressure should not be considered "covered systems" under 193.2167 when used for containment. This would preserve engineering flexibility and allow for the adoption of safe, innovative solutions.

PHMSA should also modernize its references to thermal radiation and vapor dispersion modeling. Current requirements rely on outdated models and do not allow for the use of modern mitigation technologies such as foam blocks, which are widely accepted internationally.

PHMSA should update the $10,000 property damage threshold in § 193.2515(a)(2) to reflect inflation, without such adjustment, cleanup costs for hazardous fluid spills can quickly exceed this amount—particularly when excavation of soil or gravel is required. This could result in companies being required to conduct expensive formal investigations for potentially minor spills. PHMSA should align the property damage threshold in § 193.2515 with the values used in Part 191 (and updated each year for inflation).[130]

4. Best Approach to a Part 193 Redesign

Question H.4:

How can PHMSA best design a rulemaking to update its part 193 regulations for LNG facilities to be deregulatory and lead to cost savings for the industry?

PHMSA should adopt a risk-based approach for large-scale/baseload LNG facilities in accordance with section 110 of the PIPES Act of 2020 and further allow an option for small scale, peak shaver, satellite, mobile or temporary LNG Facilities to use the same risk-based approach in lieu of the prescriptive requirements of 49 CFR 193 and NFPA 59A-2023 for all the reasons discussed in this comment document.

III. Conclusion

The Associations appreciate PHMSA's consideration of these comments and look forward to continued discussion on this topic. The Associations will continue to review its cost-benefit data and may provide supplemental comments for the Agency's review, as necessary.

[130] Section 191.3 notes that the property damage threshold for natural gas incidents, including LNG, is set at $122,000 and increased each year for inflation. Effective July 1, 2025, the property damage threshold used for natural gas incident reporting will be $149,700. *See* https://www.phmsa.dot.gov/incident-reporting (last accessed on June 10, 2025).

Respectfully submitted,

Dave Murk
Senior Director, Pipelines
Midstream and Industry Operations
American Petroleum Institute
200 Massachusetts Avenue, N.W.
Suite 1100
Washington, D.C. 20001
murkd@api.org

Charlie Riedl
Executive Director
Center for LNG
900 17th Street, N.W.
Suite 500
Washington, D.C. 20006
charlie.riedl@ngsa.org

Ashlin Bollacker
Director of Pipeline Safety Policy
Interstate Natural Gas Association of America
25 Massachusetts Ave NW, Suite 500N
Washington, DC 20001
abollacker@ingaa.org

Alan M. Chichester
Managing Director, Safety, Operations, and Engineering
American Gas Association
400 North Capitol Street, NW
Washington, DC 20001
achichester@aga.org

Erin Kurilla
Vice President, Operations and Safety
American Public Gas Association
201 Massachusetts Ave NE, Suite C-4
Washington DC 20002
ekurilla@apga.org

Paul Armstrong
Vice President, Operations
Northeast Gas Association
1800 West Park Drive
Suite 340
Westborough, MA 01581
parmstrong@northeastgas.org