PHMSA LNG
Frequently Asked Questions (FAQ)
Archive Records

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Frequently Asked Questions

http://primis.phmsa.dot.gov/lng/faqs.htm

March 25, 2014

LNG Facility Siting

Welcome. This site is administered by the Pipeline and Hazardous Materials Safety Administration (PHMSA) and provides information related specifically to PHMSA's participation as a cooperating agency in the Federal Energy Regulatory Commission's (FERC) National Environmental Policy Act (NEPA) review of liquefied natural gas (LNG) facilities.

For LNG projects that are not under FERC's jurisdiction or for additional questions associated with LNG siting, please refer to 49 CFR Part 193, Subpart B – Siting Requirements.

You may also contact:

U.S. Department of Transportation
Pipeline & Hazardous Materials Safety Administration
Kenneth Lee – Director
Engineering and Research Division
East Building, Room E22-334
1200 New Jersey Avenue, SE
Washington, DC 20590
Telephone: (202) 366-2694
Email: kenneth.lee@dot.gov

FERC is responsible for authorizing the siting and construction of onshore and near-shore LNG facilities engaged in import/export activities and the interstate transportation of natural gas by pipeline. As required by NEPA, FERC prepares environmental analyses for proposed LNG facilities under its jurisdiction.

PHMSA has authority to establish and enforce safety standards for onshore LNG facilities, and has issued its regulations in 49 CFR Part 193. PHMSA is a cooperating agency assisting the FERC in its review of facilities under NEPA. FERC's filing regulations under 18 CFR 380.12(o)(14) require FERC applicants to identify how their proposed design would comply with PHMSA's siting requirements of 49 CFR 193, Subpart B. PHMSA assists the FERC in evaluating whether an applicant's proposed siting meet those requirements.

In recent years, FERC has received significantly more applications for proposed export terminals than for import terminals and peak-shaving facilities. The review of proposed export terminals raises different technical issues and safety considerations than import terminals. FERC has sought clarification from PHMSA on design spill requirements and has requested that PHMSA advise FERC on the results of its case-by-case review of whether an LNG facility applicant is determining design spills in accordance with 49 CFR Part 193.

This site provides information regarding PHMSA's review process and the documents that operators should provide.

- Frequently Asked Questions on the application process and PHMSA's role
- Projects currently being reviewed by PHMSA
- LNG Interpretations:
    - PI-10-0200, dated March 25, 2010
    - PI-10-0005, dated July 16, 2010
    - PI-11-0001, dated December 22, 2011
    - PI-11-0011, dated February 28, 2012
    - PI-07-2012, dated Aug 21, 2012
    - PI-10-0021 dated July 7, 2010

The below FAQ list may provide an acceptable solution (or solutions) which PHMSA has carefully evaluated. We realize there may be other acceptable solutions, which we are open to consider. Other proposals require substantial technical justification to insure that any alternative approach provides an equivalent or higher level of safety. As this requires a case-by-case engineering evaluation, this may increase the design spill review time.

Frequently Asked Questions:

1. What agency or agencies have regulatory authority over the siting of LNG facilities?

There are more than 110 liquefied natural gas (LNG) facilities operating in the U.S. performing a variety of services. Most of these facilities store natural gas for "peak shaving," where the LNG is vaporized and transported in gas transmission or gas distribution pipelines for periods of peak demand. There is significant growth in the number of facilities producing LNG as a transportation vehicle fuel for trucks, trains, and ships. Depending on the location and use, several Federal agencies and State utility regulatory agencies may regulate an LNG facility.

For LNG import and export facilities, three Federal agencies share oversight for safety and security: the Federal Energy Regulatory Commission (FERC), the U.S. Coast Guard, and the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA). Under Section 3 of the Natural Gas Act of 1938, FERC is responsible for authorizing the siting and construction of onshore and near-shore LNG import or export facilities. Under Section 7 of the Natural Gas Act of 1938, FERC also issues certificates of public convenience and necessity for LNG facilities engaged in interstate natural gas transportation by pipeline. As required by the National Environmental Policy Act (NEPA), FERC prepares NEPA analyses for proposed LNG facilities under its jurisdiction. FERC currently regulates 24 operational LNG facilities. The Coast Guard has authority over the safety of LNG vessels and the marine transfer area, conducting Waterway Suitability Assessments to address navigation safety and port security issues associated with LNG ship traffic. PHMSA has authority to establish and enforce safety standards for onshore LNG facilities.

PHMSA's regulations for LNG facilities appear in Title 49, Part 193 of the Code of Federal Regulations (CFR). LNG facility applicants, when applying to FERC, are required to identify how their proposed facility would meet the siting requirements of 49 CFR Part 193. FERC consults with its cooperating agencies, including PHMSA, as needed. Once FERC approves a project and the applicant moves forward in the process, PHMSA inspects sites during and after construction and is responsible for taking enforcement action under Part 193 if necessary.

2. A FERC regulation (18 CFR § 385.2201) prohibits off-the-record communications in a contested, on-the-record proceeding. The rule is designed to limit communications between a "decisional employee" at FERC and persons outside the Commission. How do FERC's restrictions on ex parte communication affect PHMSA's communications with LNG project applicants?

The purpose of the rule is to ensure the integrity and fairness of the Commission's decisional process, and to prevent off-the-record communications between FERC decisional employees and entities outside of the Commission that are relative to the merits of a Commission proceeding. Generally, communications regarding Part 193 compliance between PHMSA and a party before the Commission do not violate FERC's ex parte rules. However, PHMSA takes care to not act as a conduit for otherwise unpermitted communications. Some communication between PHMSA and a facility applicant is expected, but PHMSA restricts those communications to matters that FERC has explicitly referred to PHMSA. In accordance with the FERC's public disclosure requirements and FERC's responsibilities under its ex parte regulations, PHMSA, as a cooperating agency, cannot release pre decisional information related to the NEPA analysis (such as working drafts of NEPA documents and PHMSA comments on those working drafts).

If PHMSA needs additional information from an applicant to resolve a matter that FERC has referred to us, PHMSA will advise FERC and the applicant of what additional information is needed and request that it be submitted to FERC's docket.

3. As an operator, how do I submit an application to install a FERC regulated LNG facility?

The FERC is responsible for authorizing the siting and construction of onshore and near-shore LNG import or export facilities and LNG facilities engaged in interstate natural gas transportation by pipeline. As an operator of one of these types of facilities, you must coordinate with the FERC in the development of the Resource Reports required for the FERC application process. Information on Resource Reports 11 & 13, which deals with the engineering detail of the LNG facility, can be found in 18 CFR 380.12 (m) & (o).

4. What types of LNG facilities require information submittal?

If an LNG facility requires FERC review and siting approval, PHMSA as a cooperating agency will require detailed information as described in these FAQs. Please refer to Subpart A of Part 193 for scope and applicability of PHMSA's regulations. There are regulations in Part 193 pertaining to siting, design, construction, equipment, maintenance, personnel qualifications and training, fire protection, and security. The operator may contact PHMSA headquarters or the PHMSA Regional Offices with any questions. PHMSA's regional contact information is located here, or you may contact PHMSA's Director of Engineering as noted below.

5. Since PHMSA is a cooperating agency in the FERC siting process, do I need to provide anything directly to PHMSA in order to help expedite the application process?

Yes. In order for PHMSA to perform an in-depth review and analysis, you should copy and forward specific items for evaluation. You should send all application materials directly to FERC, but you should also submit to PHMSA hard and digital copies of the documents noted in these FAQs to aid PHMSA in its review. Review of your application will be delayed unless you promptly submit to PHMSA substantially complete application materials. Please also be aware that PHMSA will need detailed materials without any redaction, regardless of security sensitive or proprietary information, in order to conduct a full review. If you believe your materials are security sensitive or proprietary in any way, please mark them accordingly.

Materials noted below should be addressed to:

U.S. Department of Transportation
Pipeline & Hazardous Materials Safety Administration
Kenneth Lee – Director
Engineering and Research Division
East Building, Room E22-334
1200 New Jersey Avenue, SE
Washington, DC 20590
Telephone: (202) 366-2694
Email: kenneth.lee@dot.gov

6. After I submit information to PHMSA, how long will the review process take?

There are a variety of factors which influence the timeline for review and approval including the volume of previously submitted applications, where the applicant is in the siting process, the completeness of the submitted information, and other factors. PHMSA will acknowledge receipt of the application and will begin the review process. PHMSA will contact the applicant during the review process to resolve any outstanding needs or questions.

7. After I submit the required information to PHMSA, what information do I need to file on the FERC docket?

For those projects under FERC jurisdiction, all information submitted to PHMSA should be filed on the FERC docket. PHMSA will work with the applicant to review the information. If revisions or edits are necessary, the applicant will be instructed to file an Addendum to the FERC docket.

8. What wind direction should be used in exclusion zone and other hazard calculations?

For most hazard calculations, the exclusion distance or hazard distance is calculated independent of wind direction. If the wind direction is important in the modeling methods used, the direction toward the nearest property line that can be built upon should be used. Additional wind directions may also need to be analyzed if the hazard could extend beyond other property lines.

9. What wind speed should be used in LNG facility equipment design calculations?

Wind forces are addressed in 49 CFR § 193.2067, which requires that LNG facilities be designed to withstand the direct effect of wind forces without loss of structural or functional integrity. Structural engineering design is typically performed using 3-second gust wind speeds in miles-per-hour (MPH).

For shop fabricated containers of LNG or other hazardous fluids with a capacity of not more than 70,000 gallons, the wind forces at the location of the specific facility must be based on applicable wind load data in ASCE/SEI 7-05.

For all other LNG facilities, the wind forces at the location of the specific facility must be based on one of the following:

a. an assumed sustained wind velocity of not less than 150 MPH; or
b. a sustained wind velocity of less than 150 MPH that is justified by adequate supportive data and found acceptable by the Administrator; or

c. the most critical combination of wind velocity and duration, with respect to the effect on the structure, having a probability of exceedance in a 50-year period of 0.5 percent or less, if adequate wind data are available and the probabilistic methodology is reliable.

For most structural engineering design calculations the sustained wind velocity is converted to 3-second gust wind speed using a conservative method based on sound engineering principles. The Durst curve is an acceptable conversion method in ASCE/SEI 7-05, Chapter C6. Applicants should also design all facilities to meet all applicable local or state building codes.

10. To what parts of the facility does § 193.2067(b)(2) apply?

This paragraph applies to all LNG facilities other than those that are described in §193.2067(b)(1). The term "LNG facility" is defined in 49 CFR §193.2007. The parts of the LNG plant used when liquefying natural gas or transferring, storing, or vaporizing liquefied natural gas, including piping and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation, are included as parts of an LNG facility for compliance with this design requirement.

11. What specific items should be sent to PHMSA?

The applicant should submit a Design Spill Package directly to PHMSA to aid in the review process. Detailed engineering materials are required.

The Design Spill Package should include:

a. Project description, background, purpose and details describing the proposed facility;
b. Facility location map(s), topography map(s), and site aerial photography;
c. Engineering drawings including an overall plot plan and unit plot plans for each process area or system showing the location and elevation of major equipment. Each area and piece of equipment should be clearly labeled. The unit plot plans should be detailed enough to allow for measurement of distances between various components with a reasonable degree of accuracy. The smallest scale submitted should be no smaller than 1-inch to 100-feet (1:1200);
d. Piping and instrument drawings (P&ID);
e. Process Flow Diagrams (PFD);
f. Heat and Material Balance Sheets (H&MB);
g. Piping and Equipment Inventory Table of LNG plant components;
h. Pump curves for pumps used for hazardous or flammable fluid service (if available);
i. List of all intended direct discharge points to atmosphere (this should include vents and drains);
j. Sketch on plot plan showing expected locations of major potential single accidental leakage sources;
k. Input and output summary parameters for computer program simulations, (i.e. PHAST) should be included with model submissions. This information should include input and output files and reports.

If additional information is required, PHMSA will work with the applicant on additional information submittals.

12. PHMSA reviews the design criteria for single accidental leakage sources on a case-by-case basis to determine compliance with Part 193. What information is required to assist PHMSA in its determination of the design spill criteria acceptable for use?

Applicants must provide a Piping and Equipment Inventory Table of LNG plant components, including all piping, equipment, and containers of hazardous or flammable fluid service. The Piping and Equipment Inventory Table may be submitted in either Excel (*.XL*) or character/comma separated values (*.CSV) format. A sample Piping and Equipment Inventory Table can be found in the Reference Documents.

The submitted materials should include:

a. Line segment or component number to identify potential design spill;
b. Hazardous and flammable fluid service (LNG, NG, propane, ethane, MR, NGL, condensate, hydrogen sulfide, benzene, etc.);
c. Unit plot plan drawing number reference(s) for each component;
d. Beginning point location (e.g., exchanger outlet flange) for each line;
e. Ending point location (e.g., pump suction nozzle) for each line;
f. P&ID drawing number reference(s) for each component;
g. Piping line designation or equipment tag number on P&ID;
h. Pipe diameter or pipe size, volume of container, or size of equipment;
i. Length of piping (meters); or number of components (each);
j. Failure Type or mode selected from the Failure Rate Table;
k. Corresponding Nominal Failure Rates per meter or unit;
l. Calculated Failure Rate based on length or number of units and failure rates per meter or unit listed in the Failure Rate Table;
m. Comparison of calculated failure rate to a failure rate criterion of 3×10^{-5} failures per year;
n. Process or storage conditions (e.g., fluid phase (liquid or vapor); pressure (psig); temperature (°F); flow rate, (lb/hr); composition of mixed refrigerants, NGL/Condensates, acid gas);
o. Calculated equivalent hole size based on failure modes listed in the Failure Rate Table; and
p. Calculated design spill flow rates.

13. What sort of pipe, equipment and containers should be included on the Piping and Equipment Inventory Table?

Components that should be considered to fail in the analysis for determination of the single accidental leakage source are those containing hazardous or flammable fluids and are listed on the Failure Rate Table. The table must include pipe of 2-inch diameter and larger size, valves, gaskets, expansion joints (uncommon), truck transfer hoses, truck transfer arms, ship transfer arms, process vessels, columns, heat exchangers, condensers, and storage tanks with outlet/withdrawal lines.

14. What release orientation should be used for LNG plant exclusion zone and hazard zone calculations?

Applicants should use a release orientation for hazard calculations that produces the largest exclusion zone distance.

15. Can an exclusion zone extend beyond the operator's LNG plant property line?

The operator of the LNG plant is responsible for assuring compliance with the limitations on land use within an exclusion zone. The entire exclusion zone must satisfy the descriptions in NFPA 59A Sections 2.2.3.2, 2.2.3.3, and 2.2.3.4, for as long as the facility is in operation. For example, an exclusion zone that extends past a property line into a navigable body of water or onto a public road is typically acceptable. This may not hold true if that body of water contains a dock or pier that is not controlled by the operator of the LNG plant, or if another entity could erect a building or members of the public could assemble within the exclusion zone. It is also possible to assure compliance if the operator of the LNG plant secures a legal agreement with a property owner affected by the exclusion zone that restricts the land use such that the exclusion zone definition is not violated for the life of the LNG plant.

16. Is it permissible to use spill duration of less than 10 minutes for design spill calculations?

For design spills other than those from LNG containers, the spill is defined in NFPA 59A to last "For 10 minutes or a shorter time based on demonstrable surveillance and shutdown provisions acceptable to the authority having jurisdiction." Demonstrable surveillance and shutdown should include the time required to detect that the spill is occurring, the time to alert operators to this condition, the time required for operators to take action, and the time for the system to fully respond to the shutdown action that is initiated, including any valve closure times. The spill modeling must continue after shutdown until all available system inventory is depleted.

17. What is the appropriate spill duration when a design spill or other hazard calculation involves a process vessel?

For storage or process vessels that are not LNG containers, the spill duration should include the time to de-inventory the vessel and any associated piping system unless there is an internal shut-off valve installed or an external valve mounted directly to the vessel that is protected from outside forces so that it remains functional during an emergency. When shutoff provisions exist, the spill may be limited to a 10-minute duration or in a shorter time if demonstrable surveillance and shutdown provisions exist. For piping systems, inventory in the piping system and any material normally flowing in the piping must be considered for the release scenario. It may be assumed that the normal flow through the system can be terminated in 10 minutes or in a shorter time if demonstrable surveillance and shutdown provisions exist. In all cases, the release modeling must continue until the available system inventory is depleted. Available system inventory may be modified during the event by valve closures.

18. Other than the flammable vapor dispersion and thermal radiation from hazards associated with LNG, what other hazards should be evaluated in the siting analysis for an LNG plant?

When considering hazards in any LNG plant's siting analysis, the applicant should include those associated with LNG, flammable gases, flammable refrigerants, flammable or combustible liquids, or acutely toxic materials. Vapor dispersion from liquid pools, vapor dispersion from jetting and flashing phenomena, thermal radiation from pool fires, thermal radiation from fires involving jetting and flashing phenomena (jet fires), overpressure from vapor cloud ignitions, toxic gas dispersion, and boiling liquid expanding vapor explosions (BLEVE) involving pressurized storage vessels should be included in an LNG plant's hazard evaluation if the hazard is present at the LNG plant.

19. For sizing of impoundment spill scenarios for calculating the greatest flow, should multiple pumps be considered in the calculations?

Where the greatest flow is potentially fed from multiple pumps, calculate the flow assuming that all pumps are running unless a mechanical interlock or passive preventive measure is installed that prevents all pumps from running concurrently.

20. Can a fractional time of use be applied when determining design spill scenarios with a probabilistic spill selection methodology?

When determining the design spill through the use of a probabilistic spill selection method, a time-of-use factor may be applied to some equipment groups based on their expected use. For any equipment groups that have a fractional time of use other than 1.0 (100% use), the applicant must be able to demonstrate that the equipment group can be isolated, purged, instrumented, maintained, and continually documented in such a way that the fractional time of use is traceable. In lines that operate continually but in more than one mode, each mode must be considered as a potential design spill and the sum of the fractional times of use in each mode must equal 1.0 (100% use). An example of this would be a loading/unloading line that moves a high mass rate when loading or unloading LNG, but moves a much smaller mass rate when recirculating to keep the line cooled down.

21. Do I need to consider pump run-out in release scenario calculations?

Applicants should use pump run-out (greater flow than in normal pump flow operations) in failure calculations. Pump run-out parameters are presented by the pump manufacturer as a pump curve that shows flow increasing as the discharge pressure decreases.

22. Can vacuum jacketed piping be used in an LNG plant and may the outer pipe be used for LNG impoundment?

The applicant must fully document any application of vacuum jacketed pipe (VJP) or vacuum insulated pipe (VIP). You must provide the design details of the piping as well as the locations where it is to be used. In cases where the VJP or VIP may affect the prescribed design spills, impoundment determinations, or other hazard calculations, the applicant must fully justify the position and approach being taken. PHMSA will review these applications on a case-by-case basis, and a special permit (see 49 CFR Section 190.341) may be required.

Revised: 3/25/14

Frequently Asked Questions

http://primis.phmsa.dot.gov/lng/faqs.htm

February 6, 2015

1. What agency or agencies have regulatory authority over the siting of LNG facilities?

There are more than 110 liquefied natural gas (LNG) facilities operating in the U.S. performing a variety of services. Most of these facilities store natural gas for "peak shaving," where the LNG is vaporized and transported in gas transmission or gas distribution pipelines for periods of peak demand. There is significant growth in the number of facilities producing LNG as a transportation vehicle fuel for trucks, trains, and ships. Depending on the location and use, several Federal agencies and State utility regulatory agencies may regulate an LNG facility.

For LNG import and export facilities, three Federal agencies share oversight for safety and security: the Federal Energy Regulatory Commission (FERC), the U.S. Coast Guard, and the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA). Under Section 3 of the Natural Gas Act of 1938, FERC is responsible for authorizing the siting and construction of onshore and near-shore LNG import or export facilities. Under Section 7 of the Natural Gas Act of 1938, FERC also issues certificates of public convenience and necessity for LNG facilities engaged in interstate natural gas transportation by pipeline. As required by the National Environmental Policy Act (NEPA), FERC prepares NEPA analyses for proposed LNG facilities under its jurisdiction. The Coast Guard has authority over the safety of LNG vessels and the marine transfer area, conducting Waterway Suitability Assessments to address navigation safety and port security issues associated with LNG ship traffic. PHMSA has authority to establish and enforce safety standards for onshore LNG facilities.

PHMSA's regulations for LNG facilities appear in Title 49, Part 193 of the Code of Federal Regulations (CFR). LNG facility applicants, when applying to FERC, are required to identify how their proposed facility would meet the siting requirements of 49 CFR Part 193. FERC consults with its cooperating agencies, including PHMSA, as needed. Once FERC approves a project and the applicant moves forward in the process, PHMSA inspects sites during and after construction, and during facility operation, and is responsible for taking enforcement action under Part 193 if necessary.

2. A FERC regulation (18 CFR § 385.2201) prohibits off-the-record communications in a contested, on-the-record proceeding. The rule is designed to limit communications between a "decisional employee" at FERC and persons outside the Commission. How do FERC's restrictions on ex parte communication affect PHMSA's communications with LNG project applicants?

The purpose of the rule is to ensure the integrity and fairness of the Commission's decisional process, and to prevent off-the-record communications relative to the merits of a Commission proceeding between FERC decisional employees and entities outside of the Commission. Generally, communications regarding Part 193 compliance between PHMSA and a party before the Commission do not violate FERC's ex parte rules. However, PHMSA takes care to not act as a conduit for otherwise unpermitted communications. Some communication between PHMSA and a facility applicant is expected, but PHMSA restricts those communications to matters that FERC has explicitly referred to PHMSA. In accordance with the FERC's public disclosure requirements and FERC's responsibilities under its ex parte regulations, PHMSA, as a

cooperating agency, cannot release pre decisional information related to the NEPA analysis (such as working drafts of NEPA documents and PHMSA comments on those working drafts).

If PHMSA needs additional information from an applicant to resolve a matter that FERC has referred to us, PHMSA will advise FERC and the applicant of what additional information is needed and request that it be submitted to FERC's docket.

3. As an operator, how do I submit an application to install a FERC regulated LNG facility?

The FERC is responsible for authorizing the siting and construction of onshore and near-shore LNG import or export facilities and LNG facilities engaged in interstate natural gas transportation by pipeline. As an operator of one of these types of facilities, you must coordinate with the FERC in the development of the Resource Reports required for the FERC application process. Information on Resource Reports 11 & 13, which deals with the engineering detail of the LNG facility, can be found in 18 CFR 380.12 (m) & (o).

4. What types of LNG facilities require information submittal?

If an LNG facility requires FERC review and siting approval, PHMSA as a cooperating agency will require detailed information as described in these FAQs. Please refer to Subpart A of Part 193 for scope and applicability of PHMSA's regulations. There are regulations in Part 193 pertaining to siting, design, construction, equipment, maintenance, personnel qualifications and training, fire protection, and security. If the operator has questions or needs further guidance on the applicability of Part 193 to the facility in question, then the operator may contact PHMSA headquarters or the PHMSA Regional Offices. PHMSA's regional contact information is located here, or you may contact PHMSA's Director of Engineering as noted below under FAQ #5.

5. Since PHMSA is a cooperating agency in the FERC siting process, do I need to provide anything directly to PHMSA in order to help expedite the application process?

Yes. If a facility is subject to Part 193 (see reply to FAQ #4 above), then in order for PHMSA to perform an in-depth review and analysis, you should copy and forward specific items for evaluation. You should send all application materials directly to FERC, but you should also submit to PHMSA hard and digital copies of the documents noted in these FAQs to aid PHMSA in its review. Review of your application will be delayed unless you promptly submit to PHMSA substantially complete application materials. Please also be aware that PHMSA will need detailed materials without any redaction, regardless of security sensitive or proprietary information, in order to conduct a full review. If you believe your materials are security sensitive or proprietary in any way, please mark them accordingly.

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6. After I submit information to PHMSA, how long will the review process take?

The duration of the review process varies. There are a variety of factors which influence the timeline for review and approval, including the volume of previously submitted applications, where the applicant is in the siting process, and the completeness of the submitted information. PHMSA will acknowledge receipt of the application and will begin the review process. PHMSA will contact the applicant during the review process to resolve any outstanding needs or questions.

7. After I submit the required information to PHMSA, what information do I need to file on the FERC docket?

For those projects under FERC jurisdiction, all information submitted to PHMSA should be filed on the FERC docket. PHMSA will work with the applicant to review the information. If revisions or edits are necessary, the applicant will be instructed to file an Addendum to the FERC docket.

8. What wind direction should be used in exclusion zone and other hazard calculations?

For most hazard calculations, the exclusion distance or hazard distance is calculated independent of wind direction. If the wind direction is important in the modeling methods used, the direction toward the nearest property line that can be built upon should be used. Additional wind directions may also need to be analyzed if the hazard could extend beyond other property lines.

9. What wind speed should be used in LNG facility equipment design calculations?

Wind forces are addressed in 49 CFR § 193.2067, which requires that LNG facilities be designed to withstand the direct effect of wind forces without loss of structural or functional integrity. Structural engineering design is typically performed using 3-second gust wind speeds in miles-per-hour (MPH).

For shop fabricated containers of LNG or other hazardous fluids with a capacity of not more than 70,000 gallons, the wind forces at the location of the specific facility must be based on applicable wind load data in ASCE/SEI 7-05.

For all other LNG facilities, the wind forces at the location of the specific facility must be based on one of the following:

a. an assumed sustained wind velocity of not less than 150 MPH; or
b. a sustained wind velocity of less than 150 MPH that is justified by adequate supportive data and found acceptable by the Administrator; or
c. the most critical combination of wind velocity and duration, with respect to the effect on the structure, having a probability of exceedance in a 50-year period of 0.5 percent or less, if adequate wind data are available and the probabilistic methodology is reliable.

For most structural engineering design calculations, the sustained wind velocity is converted to 3-second gust wind speed using a conservative method based on sound engineering principles. The Durst curve is an acceptable conversion method in ASCE/SEI 7-05, Chapter C6. Applicants should also design all facilities to meet all applicable local or state building codes.

10. To what parts of the facility does § 193.2067(b)(2) apply?

This paragraph applies to all LNG facilities other than those that are described in § 193.2067(b)(1). The term "LNG facility" is defined in 49 CFR § 193.2007. The parts of the LNG plant considered for compliance with this design requirement include all parts used when liquefying natural gas or transferring, storing, or vaporizing liquefied natural gas. This includes piping and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation.

11. What specific items should be sent to PHMSA?

The applicant should submit a Design Spill Package directly to PHMSA to aid in the review process. Detailed engineering materials are required as part of the Design Spill Package.

The Design Spill Package should include:

a. Project description, background, purpose and details describing the proposed facility;
b. Facility location map(s), topography map(s), and site aerial photography;
c. Engineering drawings including an overall plot plan and unit plot plans for each process area or system showing the location and elevation of major equipment. Each area and piece of equipment should be clearly labeled. The unit plot plans should be detailed enough to allow for measurement of distances between various components with a reasonable degree of accuracy. The smallest scale submitted should be no smaller than 1-inch to 100-feet (1:1200);
d. Piping and instrument drawings (P&ID);
e. Process Flow Diagrams (PFD);
f. Heat and Material Balance Sheets (H&MB);
g. Piping and Equipment Inventory Table of LNG plant components;
h. Pump curves for pumps used for hazardous or flammable fluid service (if available);
i. List of all intended direct discharge points to atmosphere (this should include vents and drains);
j. Sketch on plot plan showing expected locations of major potential single accidental leakage sources;
k. Input and output summary parameters for computer program simulations, (i.e. PHAST) should be included with model submissions. This information should include input and output files and reports.

If additional information is required, PHMSA will work with the applicant on additional information submittals.

12. PHMSA reviews the design criteria for single accidental leakage sources on a case-by-case basis to determine compliance with Part 193. What information is required to assist PHMSA in its determination of the design spill criteria acceptable for use?

Applicants must provide a Piping and Equipment Inventory Table of LNG plant components, including all piping, equipment, and containers of hazardous or flammable fluid service. The Piping and Equipment Inventory Table may be submitted in either Excel (*.XL*) or character/comma separated values (*.CSV) format.

The submitted materials should include:

a. Line segment or component number to identify potential design spill;
b. Hazardous and flammable fluid service (LNG, NG, propane, ethane, MR, NGL, condensate, hydrogen sulfide, benzene, etc.);
c. Unit plot plan drawing number reference(s) for each component;
d. Beginning point location (e.g., exchanger outlet flange) for each line;
e. Ending point location (e.g., pump suction nozzle) for each line;
f. P&ID drawing number reference(s) for each component;

g. Piping line designation or equipment tag number on P&ID;
h. Pipe diameter or pipe size, volume of container, or size of equipment;
i. Length of piping (meters); or number of components (each);
j. Failure Type or mode selected from the Failure Rate Table;
k. Corresponding Nominal Failure Rates per meter or unit;
l. Calculated Failure Rate based on length or number of units and failure rates per meter or unit listed in the Failure Rate Table;
m. Comparison of calculated failure rate to a failure rate criterion of 3x10-5 failures per year;
n. Process or storage conditions (e.g., fluid phase (liquid or vapor); pressure (psig); temperature (°F); flow rate, (lb/hr); composition of mixed refrigerants, NGL/Condensates, acid gas);
o. Calculated equivalent hole size based on failure modes listed in the Failure Rate Table; and
p. Calculated design spill flow rates.

13. What sort of pipe, equipment and containers should be included on the Piping and Equipment Inventory Table?

Components that should be considered to fail in the analysis for determination of the single accidental leakage source are those containing hazardous or flammable fluids and are listed on the Failure Rate Table. The table must include pipe of 2-inch diameter and larger size, valves, gaskets, expansion joints (uncommon), truck transfer hoses, truck transfer arms, ship transfer arms, process vessels, columns, heat exchangers, condensers, and storage tanks with outlet/withdrawal lines.

14. What release orientation should be used for LNG plant exclusion zone and hazard zone calculations?

Applicants should use a release orientation for hazard calculations that produces the largest exclusion zone distance.

15. Can an exclusion zone extend beyond the operator's LNG plant property line?

The operator of the LNG plant is responsible for assuring compliance with the limitations on land use within an exclusion zone. The entire exclusion zone must satisfy the descriptions in NFPA 59A Sections 2.2.3.2, 2.2.3.3, and 2.2.3.4, for as long as the facility is in operation. For example, an exclusion zone that extends past a property line into a navigable body of water or onto a public road is typically acceptable. This may not hold true if that body of water contains a dock or pier that is not controlled by the operator of the LNG plant, or if another entity could erect a building or members of the public could assemble within the exclusion zone. It is also possible to assure compliance if the operator of the LNG plant secures a legal agreement with a property owner affected by the exclusion zone that restricts the land use such that the exclusion zone definition is not violated for the life of the LNG plant.

16. Is it permissible to use spill duration of less than 10 minutes for design spill calculations?

For design spills other than those from LNG containers, the spill is defined in NFPA 59A to last "For 10 minutes or a shorter time based on demonstrable surveillance and shutdown provisions acceptable to the authority having jurisdiction." Demonstrable surveillance and shutdown should include the time required to detect that the spill is occurring, the time to alert operators to this condition, the time required for operators to take action, and the time for the system to fully respond to the shutdown action that is initiated, including any valve closure times. The spill modeling must continue after shutdown until all available system inventory is depleted.

17. What is the appropriate spill duration when a design spill or other hazard calculation involves a process vessel?

For storage or process vessels that are not LNG containers, the spill duration should include the time to de-inventory the vessel and any associated piping system unless there is an internal shut-off valve installed or an external valve mounted directly to the vessel that is protected from outside forces, so that it remains functional during an emergency. When shutoff provisions exist, the spill may be limited to a 10-minute duration or in a shorter time if demonstrable surveillance and shutdown provisions exist. For piping systems, inventory in the piping system and any material normally flowing in the piping must be considered for the release scenario. It may be assumed that the normal flow through the system can be terminated in 10 minutes or in a shorter time if demonstrable surveillance and shutdown provisions exist. In all cases, the release modeling must continue until the available system inventory is depleted. Available system inventory may be modified during the event by valve closures.

18. Other than the flammable vapor dispersion and thermal radiation from hazards associated with LNG, what other hazards should be evaluated in the siting analysis for an LNG plant?

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19. For sizing of impoundment spill scenarios for calculating the greatest flow, should multiple pumps be considered in the calculations?

Where the greatest flow is potentially fed from multiple pumps, calculate the flow assuming that all pumps are running, unless a mechanical interlock or passive preventive measure is installed that prevents all pumps from running concurrently.

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Specified events include:

- Change in the name of the operator of an existing LNG plant or LNG facility
- Change in the entity (e.g., company, municipality) responsible for operating an LNG facility
- Change in the primary entity responsible (i.e., with an assigned OPID) for managing or administering a safety program required by 49 CFR 193 covering pipeline facilities operated under multiple OPIDs
- Acquisition or divestiture of an existing LNG plant or LNG facility subject to 49 CFR 193
- Construction of a new LNG plant or LNG facility

Notifications must be made online via the PHMSA portal, using assigned user name and password, unless an alternate method is approved. These notifications are not posted on PHMSA's website.

LNG Construction Report – Notification Type J

24. What are the siting requirements for small LNG facilities that have an aggregate storage capacity of 70,000 gallons or less on one site?

The writer asks, "Part 193 has requirements for thermal radiation exclusion and vapor-gas dispersion exclusion zones that are required for *each* LNG container and transfer system, but NFPA 59A, 2001 edition has Table 2.2.4.1 *Distances from Impoundment Areas to Buildings and Property Lines* for small LNG facilities with total onsite storage capacity of 70,000 gallons LNG or less. Does NFPA 59A, 2001 edition, Chapter 2, Plant Siting and Layout, Paragraph 2.2.3.7 which allows use of Table 2.2.4.1 'Distances from Impoundment Areas to Buildings and Property Lines' *conflict* with Part 193 Subpart B – Siting Requirements?"

Part 193 siting requirements include the determination of exclusion zones, areas in which the operator or a government agency legally controls all activities. The exclusion zones are determined by complying with § 193.2057 *Thermal radiation protection* and § 193.2059 *Flammable vapor-gas dispersion protection*. These sections incorporate by reference NFPA 59A Paragraph 2.2.3.2 (thermal radiation distance) and Paragraphs 2.2.3.3 and 2.2.3.4 (vapor dispersion distance). NFPA 59A Paragraph 2.2.3.7 is not provided as an alternative to § 193.2057 and § 193.2059 for permanent facilities.

Under § 193.2019, mobile and temporary LNG facilities need not meet the requirements of Part 193 (including Sections 193.2057 and 193.2059) if they comply with the applicable sections of NFPA 59A that is incorporated by reference. NFPA 59A Paragraph 2.3.4 covers the requirements for such facilities. 2.3.4(g) references Table 2.2.4.1 for the spacing guidelines at mobile and temporary facilities. When Table 2.2.4.1 is used for compliance with Paragraph 2.3.4 (g), the aggregate capacity of the multiple LNG containers on the temporary site is to be used to determine facility spacing.

Revised: 2/6/15

Frequently Asked Questions

http://primis.phmsa.dot.gov:80/lng/faqs.htm

July 21, 2015

1. What agency or agencies have regulatory authority over the siting of LNG facilities?

There are more than 110 liquefied natural gas (LNG) facilities operating in the U.S. performing a variety of services. Most of these facilities store natural gas for "peak shaving," where the LNG is vaporized and transported in gas transmission or gas distribution pipelines for periods of peak demand. There is significant growth in the number of facilities producing LNG as a transportation vehicle fuel for trucks, trains, and ships. Depending on the location and use, several Federal agencies and State utility regulatory agencies may regulate an LNG facility.

For LNG import and export facilities, three Federal agencies share oversight for safety and security: the Federal Energy Regulatory Commission (FERC), the U.S. Coast Guard, and the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA). Under Section 3 of the Natural Gas Act of 1938, FERC is responsible for authorizing the siting and construction of onshore and near-shore LNG import or export facilities. Under Section 7 of the Natural Gas Act of 1938, FERC also issues certificates of public convenience and necessity for LNG facilities engaged in interstate natural gas transportation by pipeline. As required by the National Environmental Policy Act (NEPA), FERC prepares NEPA analyses for proposed LNG facilities under its jurisdiction. The Coast Guard has authority over the safety of LNG vessels and the marine transfer area, conducting Waterway Suitability Assessments to address navigation safety and port security issues associated with LNG ship traffic. PHMSA has authority to establish and enforce safety standards for onshore LNG facilities.

PHMSA's regulations for LNG facilities appear in Title 49, Part 193 of the Code of Federal Regulations (CFR). LNG facility applicants, when applying to FERC, are required to identify how their proposed facility would meet the siting requirements of 49 CFR Part 193. FERC consults with its cooperating agencies, including PHMSA, as needed. Once FERC approves a project and the applicant moves forward in the process, PHMSA inspects sites during and after construction, and during facility operation, and is responsible for taking enforcement action under Part 193 if necessary.

2. A FERC regulation (18 CFR § 385.2201) prohibits off-the-record communications in a contested, on-the-record proceeding. The rule is designed to limit communications between a "decisional employee" at FERC and persons outside the Commission. How do FERC's restrictions on ex parte communication affect PHMSA's communications with LNG project applicants?

The purpose of the rule is to ensure the integrity and fairness of the Commission's decisional process, and to prevent off-the-record communications relative to the merits of a Commission proceeding between FERC decisional employees and entities outside of the Commission. Generally, communications regarding Part 193 compliance between PHMSA and a party before the Commission do not violate FERC's ex parte rules. However, PHMSA takes care to not act as a conduit for otherwise unpermitted communications. Some communication between PHMSA and a facility applicant is expected, but PHMSA restricts those communications to matters that FERC has explicitly referred to PHMSA. In accordance with the FERC's public disclosure requirements and FERC's responsibilities under its ex parte regulations, PHMSA, as a

cooperating agency, cannot release pre decisional information related to the NEPA analysis (such as working drafts of NEPA documents and PHMSA comments on those working drafts).

If PHMSA needs additional information from an applicant to resolve a matter that FERC has referred to us, PHMSA will advise FERC and the applicant of what additional information is needed and request that it be submitted to FERC's docket.

3. As an operator, how do I submit an application to install a FERC regulated LNG facility?

The FERC is responsible for authorizing the siting and construction of onshore and near-shore LNG import or export facilities and LNG facilities engaged in interstate natural gas transportation by pipeline. As an operator of one of these types of facilities, you must coordinate with the FERC in the development of the Resource Reports required for the FERC application process. Information on Resource Reports 11 & 13, which deals with the engineering detail of the LNG facility, can be found in 18 CFR 380.12 (m) & (o).

4. What types of LNG facilities require information submittal?

If an LNG facility requires FERC review and siting approval, PHMSA as a cooperating agency will require detailed information as described in these FAQs. Please refer to Subpart A of Part 193 for scope and applicability of PHMSA's regulations. There are regulations in Part 193 pertaining to siting, design, construction, equipment, maintenance, personnel qualifications and training, fire protection, and security. If the operator has questions or needs further guidance on the applicability of Part 193 to the facility in question, then the operator may contact PHMSA headquarters or the PHMSA Regional Offices. PHMSA's regional contact information is located here, or you may contact PHMSA's Director of Engineering as noted below under FAQ #5.

5. Since PHMSA is a cooperating agency in the FERC siting process, do I need to provide anything directly to PHMSA in order to help expedite the application process?

Yes. If a facility is subject to Part 193 (see reply to FAQ #4 above), then in order for PHMSA to perform an in-depth review and analysis, you should copy and forward specific items for evaluation. You should send all application materials directly to FERC, but you should also submit to PHMSA hard and digital copies of the documents noted in these FAQs to aid PHMSA in its review. Review of your application will be delayed unless you promptly submit to PHMSA substantially complete application materials. Please also be aware that PHMSA will need detailed materials without any redaction, regardless of security sensitive or proprietary information, in order to conduct a full review. If you believe your materials are security sensitive or proprietary in any way, please mark them accordingly.

Materials noted below should be addressed to:

U.S. Department of Transportation
Pipeline & Hazardous Materials Safety Administration
Kenneth Lee – Director
Engineering and Research Division
East Building, Room E22-334
1200 New Jersey Avenue, SE
Washington, DC 20590
Telephone: (202) 366-2694
Email: kenneth.lee@dot.gov

6. After I submit information to PHMSA, how long will the review process take?

The duration of the review process varies. There are a variety of factors which influence the timeline for review and approval, including the volume of previously submitted applications, where the applicant is in the siting process, and the completeness of the submitted information. PHMSA will acknowledge receipt of the application and will begin the review process. PHMSA will contact the applicant during the review process to resolve any outstanding needs or questions.

7. After I submit the required information to PHMSA, what information do I need to file on the FERC docket?

For those projects under FERC jurisdiction, all information submitted to PHMSA should be filed on the FERC docket. PHMSA will work with the applicant to review the information. If revisions or edits are necessary, the applicant will be instructed to file an Addendum to the FERC docket.

8. What wind direction should be used in exclusion zone and other hazard calculations?

For most hazard calculations, the exclusion distance or hazard distance is calculated independent of wind direction. If the wind direction is important in the modeling methods used, the direction toward the nearest property line that can be built upon should be used. Additional wind directions may also need to be analyzed if the hazard could extend beyond other property lines.

9. What wind speed should be used in LNG facility equipment design calculations?

Wind forces are addressed in 49 CFR § 193.2067, which requires that LNG facilities be designed to withstand the direct effect of wind forces without loss of structural or functional integrity. Structural engineering design is typically performed using 3-second gust wind speeds in miles-per-hour (MPH).

For shop fabricated containers of LNG or other hazardous fluids with a capacity of not more than 70,000 gallons, the wind forces at the location of the specific facility must be based on applicable wind load data in ASCE/SEI 7-05.

For all other LNG facilities, the wind forces at the location of the specific facility must be based on one of the following:

a. an assumed sustained wind velocity of not less than 150 MPH; or
b. a sustained wind velocity of less than 150 MPH that is justified by adequate supportive data and found acceptable by the Administrator; or
c. the most critical combination of wind velocity and duration, with respect to the effect on the structure, having a probability of exceedance in a 50-year period of 0.5 percent or less, if adequate wind data are available and the probabilistic methodology is reliable.

For most structural engineering design calculations, the sustained wind velocity is converted to 3-second gust wind speed using a conservative method based on sound engineering principles. The Durst curve is an acceptable conversion method in ASCE/SEI 7-05, Chapter C6. Applicants should also design all facilities to meet all applicable local or state building codes.

10. To what parts of the facility does § 193.2067(b)(2) apply?

This paragraph applies to all LNG facilities other than those that are described in § 193.2067(b)(1). The term "LNG facility" is defined in 49 CFR § 193.2007. The parts of the LNG plant considered for compliance with this design requirement include all parts used when liquefying natural gas or transferring, storing, or vaporizing liquefied natural gas. This includes piping and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation.

11. What specific items should be sent to PHMSA?

The applicant should submit a Design Spill Package directly to PHMSA to aid in the review process. Detailed engineering materials are required as part of the Design Spill Package.

The Design Spill Package should include:

a. Project description, background, purpose and details describing the proposed facility;
b. Facility location map(s), topography map(s), and site aerial photography;
c. Engineering drawings including an overall plot plan and unit plot plans for each process area or system showing the location and elevation of major equipment. Each area and piece of equipment should be clearly labeled. The unit plot plans should be detailed enough to allow for measurement of distances between various components with a reasonable degree of accuracy. The smallest scale submitted should be no smaller than 1-inch to 100-feet (1:1200);
d. Piping and instrument drawings (P&ID);
e. Process Flow Diagrams (PFD);
f. Heat and Material Balance Sheets (H&MB);
g. Piping and Equipment Inventory Table of LNG plant components;
h. Pump curves for pumps used for hazardous or flammable fluid service (if available);
i. List of all intended direct discharge points to atmosphere (this should include vents and drains);
j. Sketch on plot plan showing expected locations of major potential single accidental leakage sources;
k. Input and output summary parameters for computer program simulations, (i.e. PHAST) should be included with model submissions. This information should include input and output files and reports.

If additional information is required, PHMSA will work with the applicant on additional information submittals.

12. PHMSA reviews the design criteria for single accidental leakage sources on a case-by-case basis to determine compliance with Part 193. What information is required to assist PHMSA in its determination of the design spill criteria acceptable for use?

Applicants must provide a Piping and Equipment Inventory Table of LNG plant components, including all piping, equipment, and containers of hazardous or flammable fluid service. The Piping and Equipment Inventory Table may be submitted in either Excel (*.XL*) or character/comma separated values (*.CSV) format.

The submitted materials should include:

a. Line segment or component number to identify potential design spill;
b. Hazardous and flammable fluid service (LNG, NG, propane, ethane, MR, NGL, condensate, hydrogen sulfide, benzene, etc.);
c. Unit plot plan drawing number reference(s) for each component;
d. Beginning point location (e.g., exchanger outlet flange) for each line;
e. Ending point location (e.g., pump suction nozzle) for each line;
f. P&ID drawing number reference(s) for each component;

g. Piping line designation or equipment tag number on P&ID;
h. Pipe diameter or pipe size, volume of container, or size of equipment;
i. Length of piping (meters); or number of components (each);
j. Failure Type or mode selected from the Failure Rate Table;
k. Corresponding Nominal Failure Rates per meter or unit;
l. Calculated Failure Rate based on length or number of units and failure rates per meter or unit listed in the Failure Rate Table;
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25. The abundant supply of domestic natural gas is driving development of new ways to use, process, and transport LNG. Can PHMSA provide guidance as to which LNG facilities are regulated under 49 CFR Part 193?

The Pipeline Safety Statute codified in 49 U.S. Code § 60101, et seq, directs US DOT to establish and enforce standards for liquefied natural gas pipeline facilities. An LNG facility is a gas pipeline facility used for converting, transporting or storing liquefied natural gas.

Many LNG facilities are subject to the regulatory and enforcement authority of the Department of Transportation through PHMSA. A simple but not complete test to determine if an LNG facility is regulated under 49 CFR Part 193 is to identify both the source and the consumer of the LNG. The facility is regulated under 49 CFR Part 193 if the LNG facility either receives from or delivers to a 49 CFR Part 192 pipeline.

49 CFR Part 193 does not apply to:

1. LNG facilities used by ultimate consumers of LNG or natural gas.
2. LNG facilities used in the course of natural gas treatment or hydrocarbon extraction that do not store LNG.
3. In marine cargo transfer systems and associated facilities, any matter other than siting pertaining to the system or facilities between the marine vessel and the last manifold (or, in the absence of a manifold, the last valve) located immediately before a storage tank.
4. Any LNG facility located in navigable waters (as defined in Section 3(8) of the Federal Power Act (16 U.S.C. 796(8)).

Operators should assume an LNG facility used in the transportation of gas by a 49 CFR Part 192 pipeline is regulated under 49 CFR Part 193 unless specifically exempted in Section 193.2001(b). LNG facilities may be regulated by PHMSA even though they are not regulated by the FERC. The 'ultimate consumer' provision provides a very limited exemption from 49 CFR Part 193. PHMSA interpretation # PI-10-0025 provides guidance. Here is an excerpt:

> *During the rulemaking that led to the adoption of § 193.2001(b)(1), OPS explained that the intent of that provision was to create an exception for "an LNG facility used by the ultimate consumer of the product". Likewise, in responding to a series of questions from a congressional committee, OPS stated that the exception in § 193.2001(b)(1), was designed for "small" facilities which are "generally located in industrial plants ... [to] serve as a supply of energy or feedstock for the plant." Unlike these examples, the Maine LMF facilities would be used to produce LNG for sale and distribution by truck, not solely for onsite consumption. Therefore, OPS concludes that your client's facilities would not qualify for the end-user exception in § 193.2001(b)(1).*

Revised: 7/21/15

Frequently Asked Questions

http://primis.phmsa.dot.gov:80/lng/faqs.htm

August 12, 2015

The FAQs may provide an acceptable solution(s). There may be other acceptable solutions. Some proposals require substantial technical justification to insure that any alternative approach provides an equivalent or higher level of safety. As this requires a case-by-case engineering evaluation, this may increase PHMSA's review time.

These FAQs are divided into four categories:

(G) General
(D) Design
(DS) Design Spill Definition
(H) Hazards and Hazards Modeling

(G) General

G1. The abundant supply of domestic natural gas is driving development of new ways to use, process, and transport LNG. Can PHMSA provide guidance as to which LNG facilities are regulated under 49 CFR Part 193?

The Pipeline Safety Statute codified in 49 U.S. Code § 60101, et seq, directs US DOT to establish and enforce standards for liquefied natural gas pipeline facilities. An LNG facility is a gas pipeline facility used for converting, transporting or storing liquefied natural gas.

Many LNG facilities are subject to the regulatory and enforcement authority of the Department of Transportation through PHMSA. A simple but not complete test to determine if an LNG facility is regulated under 49 CFR Part 193 is to identify both the source and the consumer of the LNG. The facility is regulated under 49 CFR Part 193 if the LNG facility either receives from or delivers to a 49 CFR Part 192 pipeline.

49 CFR Part 193 does not apply to:

1. LNG facilities used by ultimate consumers of LNG or natural gas.
2. LNG facilities used in the course of natural gas treatment or hydrocarbon extraction that do not store LNG.
3. In marine cargo transfer systems and associated facilities, any matter other than siting pertaining to the system or facilities between the marine vessel and the last manifold (or, in the absence of a manifold, the last valve) located immediately before a storage tank.
4. Any LNG facility located in navigable waters (as defined in Section 3(8) of the Federal Power Act (16 U.S.C. 796(8)).

Operators should assume an LNG facility used in the transportation of gas by a 49 CFR Part 192 pipeline is regulated under 49 CFR Part 193 unless specifically exempted in Section 193.2001(b). LNG facilities may be regulated by PHMSA even though they are not regulated by the FERC. The 'ultimate consumer' provision provides a very limited exemption from 49 CFR Part 193. PHMSA interpretation # PI-10-0025 provides guidance. Here is an excerpt:

During the rulemaking that led to the adoption of § 193.2001(b)(1), OPS explained that the intent of that provision was to create an exception for "an LNG facility used by the ultimate consumer of the product". Likewise, in responding to a series of questions from a congressional committee, OPS stated that the exception in § 193.2001(b)(1), was designed for "small" facilities which are "generally located in industrial plants ... [to] serve as a supply of energy or feedstock for the plant." Unlike these examples, the Maine LMF facilities would be used to produce LNG for sale and distribution by truck, not solely for onsite consumption. Therefore, OPS concludes that your client's facilities would not qualify for the end-user exception in § 193.2001(b)(1).

G2. What agency or agencies have regulatory authority over the siting of LNG facilities?

There are more than 110 liquefied natural gas (LNG) facilities operating in the U.S. performing a variety of services. Most of these facilities store LNG for "peak shaving," where the LNG is vaporized and transported in gas transmission or gas distribution pipelines for periods of peak demand. There is significant growth in the number of facilities producing LNG as a transportation vehicle fuel for trucks, buses, trains, and ships. Depending on the location and use, several Federal agencies and State utility regulatory agencies may regulate an LNG facility.

For LNG import and export facilities located onshore, three Federal agencies share oversight for safety and security: the Federal Energy Regulatory Commission (FERC), the U.S. Coast Guard, and the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA). Under Section 3 of the Natural Gas Act of 1938, FERC is responsible for authorizing the siting and construction of onshore and near-shore LNG import or export facilities. Under Section 7 of the Natural Gas Act of 1938, FERC also issues certificates of public convenience and necessity for LNG facilities engaged in interstate natural gas transportation by pipeline. As required by the National Environmental Policy Act (NEPA), FERC prepares NEPA analyses for proposed LNG facilities under its jurisdiction. The Coast Guard has authority over the safety of LNG vessels and the marine transfer area, conducting Waterway Suitability Assessments to address navigation safety and port security issues associated with LNG ship traffic. PHMSA has authority to establish and enforce safety standards for onshore LNG facilities.

PHMSA's regulations for LNG facilities appear in Title 49, Part 193 of the Code of Federal Regulations (CFR). LNG facility applicants, when applying to FERC, are required to identify how their proposed facility would meet the siting requirements of 49 CFR Part 193. FERC consults with its cooperating agencies, including PHMSA, as needed. Once FERC approves a project and the applicant moves forward in the process, PHMSA inspects sites during and after construction, and during facility operation, and is responsible for taking enforcement action under Part 193 if necessary.

G3. As an operator, how do I submit an application to install a FERC regulated LNG facility?

The FERC is responsible for authorizing the siting and construction of onshore and near-shore LNG import or export facilities and LNG facilities engaged in interstate natural gas transportation by pipeline. As an operator of one of these types of facilities, you must coordinate with the FERC in the development of the Resource Reports required for the FERC application process. Information on Resource Reports 11 & 13, which deals with the engineering detail of the LNG facility, can be found in 18 CFR 380.12 (m) & (o).

G4. What types of LNG facilities require information submittal?

If an LNG facility requires FERC review and siting approval, PHMSA as a cooperating agency will require detailed information as described in these FAQs. Please refer to Subpart A of Part 193 for scope and applicability of PHMSA's regulations. There are regulations in Part 193 pertaining to siting, design, construction, equipment, maintenance, personnel qualifications and training, fire protection, and security. If the operator has questions or needs further guidance on the applicability of Part 193 to the facility in question, then the operator may contact PHMSA headquarters or the PHMSA Regional Offices. PHMSA's regional contact information is located here, or you may contact PHMSA's Director of Engineering as noted below under FAQ #G6.

G5. Does PHMSA have an application or permitting process for new or modified LNG facilities that are subject to the jurisdiction of Part 193 but does not require FERC review?

PHMSA does not require an application process and does not have authority for permitting LNG facilities. PHMSA requires LNG operators submit information to the National Registry of Pipeline and LNG Operators database 60 days prior to commencing construction when the project cost are $10 million or more. See FAQ #G10 below for more information.

LNG operators may be required to submit an application to the Federal Energy Regulatory Agency (FERC) or the appropriate state agency. Operators must notify the State Pipeline Safety Agencies at least 2 weeks prior to the installation of portable LNG facilities and provide information prescribed in § 193.2019 (b).

Determining how to comply with 49 CFR 193 is the responsibility of the operator. PHMSA is available to answer your questions. Please contact Ken Lee, Director, Engineering and Research Division
(202) 366-2694 or by email kenneth.lee@dot.gov.

G6. Since PHMSA is a cooperating agency in the FERC siting process, do I need to provide anything directly to PHMSA in order to help expedite the application process?

Yes. If a facility is subject to Part 193 (see reply to FAQ #G3 above), then in order for PHMSA to perform an in-depth review and analysis, you should copy and forward specific items for evaluation. You should send all application materials directly to FERC, but you should also submit to PHMSA hard and digital copies of the documents noted in these FAQs to aid PHMSA in its review. Review of your application will be delayed unless you promptly submit to PHMSA substantially complete application materials. Please also be aware that PHMSA will need detailed materials without any redaction, regardless of security sensitive or proprietary information, in order to conduct a full review. If you believe your materials are security sensitive or proprietary in any way, please mark them accordingly.

Materials noted below should be addressed to:

U.S. Department of Transportation
Pipeline & Hazardous Materials Safety Administration
Kenneth Lee – Director
Engineering and Research Division
East Building, Room E22-334
1200 New Jersey Avenue, SE
Washington, DC 20590
Telephone: (202) 366-2694
Email: kenneth.lee@dot.gov

G7. What specific items should be sent to PHMSA?

The applicant should submit a Design Spill Package directly to PHMSA to aid in the review process. Detailed engineering materials are required as part of the Design Spill Package.

The Design Spill Package should include:

a. Project description, background, purpose and details describing the proposed facility;
b. Hazard reports, including any attachments and referenced reports;
c. Facility location map(s), topography map(s), and site aerial photography;
d. Engineering drawings including an overall plot plan showing the project's property boundary and unit plot plans for each process area or system showing the location and elevation of major equipment. Each area and piece of equipment should be clearly labeled. The unit plot plans should be detailed enough to allow for measurement of distances between various components with a reasonable degree of accuracy. The smallest scale submitted should be no smaller than 1-inch to 100-feet (1:1200);
e. Piping and instrument drawings (P&ID;);
f. Process Flow Diagrams (PFD);
g. Heat and Material Balance Sheets (H&MB;);
h. Piping and Equipment Inventory Table of LNG plant components;
i. Pump and compressor curves for pumps and compressors used for hazardous fluid service (as available);
j. List of all intended direct discharge points to atmosphere (this should include vents and drains);
k. Sketch on plot plan showing expected locations and elevations of major potential single accidental leakage sources;
l. Dimensions, capacities, and thermal properties for any impoundments associated with this project;
m. Design details for vapor barriers;
n. Input and output summary parameters for computer program simulations, (i.e. PHAST) should be included with model submissions. This information should include input and output files and reports.

If additional information is required, PHMSA will work with the applicant on additional information submittals.

G8. After I submit information to PHMSA, how long will the review process take?

The duration of the review process varies. There are a variety of factors which influence the timeline for review and approval, including the volume of previously submitted applications, where the applicant is in the siting process, and the completeness of the submitted information. PHMSA will acknowledge receipt of the application and will begin the review process. PHMSA will contact the applicant during the review process to resolve any outstanding needs or questions.

G9. After I submit the required information to PHMSA, what information do I need to file on the FERC docket?

For those projects under FERC jurisdiction, all information submitted to PHMSA should be filed on the FERC docket. PHMSA will work with the applicant to review the information. If revisions or edits are necessary, the applicant will be instructed to file an addendum to the FERC docket.

G10. A FERC regulation (18 CFR § 385.2201) prohibits off-the-record communications in a contested, on-the-record proceeding. The rule is designed to limit communications between a "decisional employee" at FERC and persons outside the Commission. How do FERC's restrictions on ex parte communication affect PHMSA's communications with LNG project applicants?

The purpose of the rule is to ensure the integrity and fairness of the Commission's decisional process, and to prevent off-the-record communications relative to the merits of a Commission proceeding between FERC decisional employees and entities outside of the Commission. Generally, communications regarding Part 193 compliance between PHMSA and a party before the Commission do not violate FERC's ex parte rules. However, PHMSA takes care to not act as a conduit for otherwise unpermitted communications. Some communication between PHMSA and a facility applicant is expected, but PHMSA restricts those communications to matters that FERC has explicitly referred to PHMSA. In accordance with the FERC's public disclosure requirements and FERC's responsibilities under its ex parte regulations, PHMSA, as a cooperating agency, cannot release pre decisional information related to the NEPA analysis (such as working drafts of NEPA documents and PHMSA comments on those working drafts).

If PHMSA needs additional information from an applicant to resolve a matter that FERC has referred to us, PHMSA will advise FERC and the applicant of what additional information is needed and request that it be submitted to FERC's docket.

G11. How do operators notify PHMSA that construction of an LNG facility will be commencing?

The Operator Registry Notification is used by operators to report new construction, asset-changing or program-changing events associated with LNG facilities. Each operator of an LNG plant or LNG facility is required to submit notification of specified events to PHMSA in accordance with § 191.22(c) either 60 days or more before the planned occurrence or 60 days or less after the occurrence, as specified in these regulations.

Specified events include:

- Change in the name of the operator of an existing LNG plant or LNG facility;
- Change in the entity (e.g., company, municipality) responsible for operating an LNG facility;
- Change in the primary entity responsible (i.e., with an assigned operator identification (OPID) number) for managing or administering a safety program required by 49 CFR 193 covering pipeline facilities operated under multiple OPIDs;
- Acquisition or divestiture of an existing LNG plant or LNG facility subject to 49 CFR 193;
- Construction of a new LNG plant or LNG facility;

Notifications must be made online via the PHMSA portal, using assigned user name and password, unless an alternate method is approved. These notifications are not posted on PHMSA's website.

LNG Construction Report – Notification Type J

G12. What are the siting requirements for small LNG facilities that have an aggregate storage capacity of 70,000 gallons or less on one site?

The writer asks, "Part 193 has requirements for thermal radiation exclusion and vapor-gas dispersion exclusion zones that are required for *each* LNG container and transfer system, but NFPA 59A, 2001 edition has Table 2.2.4.1 *Distances from Impoundment Areas to Buildings and Property Lines* for small LNG facilities with total onsite storage capacity of 70,000 gallons LNG or less. Does NFPA 59A, 2001 edition, Chapter 2, Plant Siting and Layout, Paragraph 2.2.3.7 which allows use of Table 2.2.4.1 'Distances from Impoundment Areas to Buildings and Property Lines' *conflict* with Part 193 Subpart B – Siting Requirements?"

Part 193 siting requirements include the determination of exclusion zones, areas in which the operator or a government agency legally controls all activities. The exclusion zones are determined by complying with § 193.2057 *Thermal radiation protection* and § 193.2059 *Flammable vapor-gas dispersion protection*. These sections incorporate by reference NFPA 59A Paragraph 2.2.3.2 (thermal radiation distance) and Paragraphs 2.2.3.3 and 2.2.3.4 (vapor dispersion distance). NFPA 59A Paragraph 2.2.3.7 is not provided as an alternative to § 193.2057 and § 193.2059 for permanent facilities.

Under § 193.2019, mobile and temporary LNG facilities need not meet the requirements of Part 193 (including Sections 193.2057 and 193.2059) if they comply with the applicable sections of NFPA 59A that is incorporated by reference. NFPA 59A Paragraph 2.3.4 covers the requirements for such facilities. 2.3.4(g) references Table 2.2.4.1 for the spacing guidelines at mobile and temporary facilities. When Table 2.2.4.1 is used for compliance with Paragraph 2.3.4 (g), the aggregate capacity of the multiple LNG containers on the temporary site is to be used to determine facility spacing.

(D) Design

D1. What wind speed should be used in LNG facility equipment design calculations?

Wind forces are addressed in 49 CFR § 193.2067, which requires that LNG facilities be designed to withstand the direct effect of wind forces without loss of structural or functional integrity. Structural engineering design is typically performed using 3-second gust wind speeds in miles-per-hour (mph).

For shop fabricated containers of LNG or other hazardous fluids with a capacity of not more than 70,000 gallons, the wind forces at the location of the specific facility must be based on applicable wind load data in ASCE/SEI 7-05.

For all other LNG facilities, the wind forces at the location of the specific facility must be based on one of the following:

a. an assumed sustained wind velocity of not less than 150 MPH; or
b. a sustained wind velocity of less than 150 MPH that is justified by adequate supportive data and found acceptable by the Administrator; or
c. the most critical combination of wind velocity and duration, with respect to the effect on the structure, having a probability of exceedance in a 50-year period of 0.5 percent or less, if adequate wind data are available and the probabilistic methodology is reliable.

For most structural engineering design calculations, the sustained wind velocity is converted to 3-second gust wind speed using a conservative method based on sound engineering principles. The Durst curve is an acceptable conversion method in ASCE/SEI 7-05, Chapter C6. Using this method, a sustained wind velocity of 150 mph is equivalent to a 183 mph 3-second gust. Applicants should also design all facilities to meet all applicable local or state building codes.

D2. To what parts of the facility does § 193.2067(b)(2) apply?

This paragraph applies to all LNG facilities other than those that are described in § 193.2067(b)(1). The term “LNG facility” is defined in 49 CFR § 193.2007. The parts of the LNG plant considered for compliance with this design requirement include all parts used when liquefying natural gas or transferring, storing, or vaporizing liquefied natural gas. This includes piping and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation.

D3. Should the wind speed design criteria of 193.2067 be applied to vapor barriers at the LNG plant?

Since vapor barriers are installed for the purpose of reducing the extent of exclusion zones, they are a part of the LNG facilities and subject to the regulatory wind speed requirements. Vapor barriers must be functional while the LNG facility is in operation.

D4. Can vacuum jacketed piping be used in an LNG plant and may the outer pipe be used for LNG impoundment?

The applicant must fully document any application of vacuum jacketed pipe (VJP) or vacuum insulated pipe (VIP). The design details of the piping as well as the locations where it is to be used must be provided. In cases where the VJP or VIP may affect the prescribed design spills, impoundment determinations, or other hazard calculations, the applicant must fully justify the position and approach being taken. PHMSA will review these applications on a case-by-case basis, and a special permit (see 49 CFR Section 190.341) may be required.

(DS) Design Spill Determination

DS1. PHMSA reviews the design criteria for design spills on a case-by-case basis to determine compliance with Part 193. What information is required to assist PHMSA in its determination of the design spill criteria acceptable for use?

Applicants must provide a piping and equipment inventory table of LNG plant components in hazardous or flammable fluid service. The piping and equipment inventory table should be submitted in Excel (*.XL*) format. Separate tabs or lists should be used for each type of hazardous fluid, as well as a separate tab or list to present all of the final design spill selections.

The table should include the following information:

a. Line segment or component number to identify potential design spill;
b. Hazardous fluid service (LNG, natural gas, refrigerants (such as ammonia, propane, ethane, mixed refrigerant), natural gas liquids or gas condensate, hydrogen sulfide, benzene, etc.) for each component;
c. General plant area or service (e.g. liquefaction train, refrigerant storage, marine area, etc.), unless the entire project is confined to one area;
d. Unit plot plan drawing number reference(s) for each component;
e. Beginning point location (e.g., exchanger outlet flange) for each line;
f. Ending point location (e.g., pump suction nozzle) for each line;
g. P&IDs and drawing number reference(s) for each component;
h. Piping line designation or equipment tag number on P&ID;
i. Pipe diameter or pipe size, volume of container, or size of equipment;
j. Length of piping (feet and meters); or number of components (each);
k. Maximum connection diameter in the piping segment;
l. Failure type or mode selected from the failure rate table;
m. Corresponding nominal failure rates per meter or unit;
n. Calculated failure rate based on pipe length or number of units and failure rates per meter or unit listed in the failure rate table;
o. Comparison of calculated failure rate to a failure rate criterion of 3x10-5 failures per year;

p. Process or storage conditions (e.g., fluid phase (liquid or vapor); density (lb/ft3); pressure (psig); temperature (°F); flow rate, (lb/hr); composition of mixed refrigerants, NGL/Condensates, acid gas);
q. Process flow diagram and corresponding heat and material balance stream number;
r. Heat and material design case (e.g., rich, lean, average, etc.);
s. Calculated equivalent hole size based on failure modes listed in the failure rate table; and
t. Calculated design spill flow rates.
u. Design spills selected with release duration, de-inventory duration, height, direction, orientation, rainout percentage, flashing and jetting vapor mass flow rate, pool vaporization mass flow rate, and total vapor mass flow rate

DS2. What sorts of pipe, equipment, and containers should be included on the piping and equipment inventory table?

Components that should be considered to fail in the analysis for determination of the single accidental leakage source are those containing hazardous or flammable fluids and are listed on the Failure Rate Table. The table must include pipe of 2-inch diameter and larger size, valves, gaskets, expansion joints, truck transfer hoses, truck transfer arms, ship transfer arms, pumps, compressors, process vessels, columns, heat exchangers, condensers, and storage tanks.

DS3. 49 CFR 193 requires that design spills for an LNG plant be selected according to NFPA 59A-2001 Paragraph 2.2.3.5. NFPA 59A requires the evaluation of accidental flow from "any single accidental leakage source" (SALS) but does not define this term. How should I select SALS events in an LNG plant?

For piping and equipment that handle LNG, flammable refrigerants, toxic components, or any other hazardous fluid, release sources may be chosen using the following guidelines. The SALS selection methodology is applied to determine the maximum hole sizes of interest for the most significant releases of each hazardous fluid in each portion of the LNG plant. (The SALS selections are one component of design spill definition. Please refer to other FAQs for additional design spill definition topics.)

a. For all piping and equipment (including transfer hoses and arms), the failure rate table should be applied to determine if the 3×10^{-5} per year failure rate criterion is equaled or exceeded; and,
b. For all piping, the failure rate table is applied to a piping segment (i.e., length of pipe) and the hole size is chosen based on equaling or exceeding the 3×10^{-5} per year failure rate criterion. The following rules should be applied to piping segments:
    1. Piping segments should be selected to begin and end at pieces of equipment and include all tees, loops, and branches; and
    2. A principle to be applied for piping segment begin/end locations is at points where the process conditions change significantly (typically temperature, pressure, or composition); and
    3. Piping segments should not be initiated or terminated at valves (e.g. pressure regulating valves, flow control valves, etc.), piping spec changes, flange connections, flow meters, reducers, piping fittings, or other piping appurtenances; and
    4. Piping segment length should be based on piping isometrics but may be based on engineering estimates of the piping path, accounting for vertical distances as well as horizontal distances.
c. For piping connections less than 6 inches in diameter, a full-bore rupture (guillotine failure) is assumed at the point of connection to the equipment item or piping. Small diameter piping is typically used for connections to equipment (e.g., storage tanks, vessels, heat exchangers, pumps, etc.) or to piping as drain lines, vent lines, nitrogen purge lines, PSV connections, valve bypass connections, instrument connections, etc.

d. Regardless of the results obtained by the failure rate table or connections approach above, a minimum 2-inch hole should be considered at any location along any piping of 2 inches or larger diameter.

DS4. Can a fractional time of use be applied when determining SALS events with a probabilistic spill selection methodology?

When determining the design spill through the use of a probabilistic spill selection method, a time-of-use factor may be applied to some piping or equipment groups based on their expected use. For groups that have a fractional time of use other than 1.0 (100% use), the applicant must be able to demonstrate that the group can be isolated, purged, instrumented, maintained, and continually documented in such a way that the fractional time of use is traceable. In groups that operate continually but in more than one mode, each mode must be considered as a potential design spill source and the sum of the fractional times of use in each mode must equal 1.0 (100% use). An example of this would be a loading/unloading line that moves a high mass rate when loading or unloading LNG, but moves a much smaller mass rate when recirculating to keep the line cooled down.

DS5. Is the largest size hole always used as the hole size in release modeling?

Not necessarily. For any defined maximum hole size, the applicant must demonstrate that that the hole size selected produces the greatest vapor dispersion distance when accounting for the mechanisms of jetting, flashing, aerosol formation, and rain-out. If a smaller hole size creates a larger vapor dispersion hazard distance, that smaller hole size should be used to define the design spill event. This applies to all single accidental leakage sources, including failures at piping, piping connections, and all other equipment (e.g., transfer hoses, vessels, heat exchangers, pumps, valves, flanges, etc.).

DS6. What are the proper release height and orientation to use for a design spill?

For each design spill identified, release height and orientation should be selected to define the largest vapor dispersion hazard distance while properly characterizing the release scenario. If an applicant can show that only certain release orientations are possible based on the piping connections and direction of the piping (e.g., vertically upward for connections to relief valve inlet piping, vertically downward for gravity drain connections, and downward for shrouded piping) then a specific orientation may be used in the modeling. All other piping and equipment failures must consider all horizontal and vertical directional orientations.

DS7. How are release locations defined?

For connection failures, the release location can be identified at the specific point of connection in the LNG plant. For piping segments to which the failure rate table has been applied, the selected hole can occur at any location along the piping segment. If vapor barriers, shrouds, or pipe-in-pipe designs are used to reduce the vapor dispersion distance, locations potentially not impacted by the vapor barrier, shroud, or pipe-in-pipe should also be selected.

DS8. How do I determine the process conditions to evaluate for hazard modeling?

Process conditions should be based on heat and material balance modes of operation and design cases (e.g., rich, lean, average, etc.) that produce the worst case dispersion results from flashing and jetting and liquid releases. The leakage sources from branch connections should be considered using the potential operational conditions along the pipe as well as the potential operational conditions that could be experienced at or near the branch pipe connection to a main process line. In cases that would reduce the back pressure on pump(s) or compressor(s), the flow rates should consider the potential increased pump or compressor flow determined by the pump and compressor curve(s) as detailed in D10 and also consider the decrease in temperature from depressurization.

DS9. Is it permissible to use spill duration of less than 10 minutes for design spill calculations?

For design spills other than those from LNG containers, the event is defined in NFPA 59A to last "for 10 minutes or a shorter time based on demonstrable surveillance and shutdown provisions acceptable to the authority having jurisdiction." Demonstrable surveillance and shutdown should include the time required to detect that the spill is occurring, the time to alert operators to this condition, the time required for operators to take action, and the time for the system to fully respond to the shutdown action that is initiated, including any valve closure times. In this case, the applicant should provide a detailed justification or demonstrate that a maximum or steady state dispersion distance has already been reached by the shorter time.

In cases where a system may deplete its inventory in less than 10 minutes, a release duration of less than 10 minutes may be used. In this case, the applicant should provide a detailed justification or demonstrate that a maximum or steady state dispersion distance has already been reached by the shorter time.

DS10. What considerations should be given to system inventory in the design spill definition?

The release modeling should account for the available system inventory (including pipework, process vessels, and other process equipment), the normal flow of fluid into the system, and the demonstrable surveillance and shutdown provisions that may apply. The release modeling should also continue (even beyond 10 minutes) until the available system inventory is depleted; available system inventory may be modified during the event by valve closures. For systems that rely on isolation by emergency shutdown valves, the valves must be protected from failure, including fire and external impacts.

If the event the duration would potentially be greater than 10 minutes, release and dispersion modeling should continue after 10 minutes unless a release is demonstrated to reach its furthest vapor dispersion extent within 10 minutes.

DS11. Do I need to consider pump run-out in release scenario calculations?

Yes. Applicants should use pump run-out (greater flow than in normal pump flow operations) in failure calculations if the pump design allows increases in flow as the discharge pressure is reduced. Pump run-out parameters are presented by the pump manufacturer as a pump curve that shows flow increasing as the discharge pressure decreases. If pump run-out flows are not known at the time of submittal, engineering estimates may be employed provisionally.

DS12. Should multiple pumps be considered when calculating the greatest flow from a spill to size impoundments?

Where the greatest flow is potentially fed from multiple pumps, calculate the flow assuming that all pumps are running at possible pump run-out conditions, unless a mechanical interlock or passive preventive measure is installed that prevents all pumps from running concurrently.

(H) Hazards and Hazards Modeling

H1. Other than the flammable vapor dispersion and thermal radiation from hazards associated with LNG, what other hazards should be evaluated in the siting analysis for an LNG plant?

According to NFPA 59A-2001 Paragraph 2.1.1(d), (incorporated by reference in 49 CFR Part 193), all hazards that can affect the safety of the public or plant personnel are to be considered. In addition to LNG, the applicant should consider hazards associated with flammable gases, flammable refrigerants, flammable or combustible liquids, or acutely toxic materials. If present at the LNG plant, hazards including vapor dispersion from liquid pools, vapor dispersion from jetting and flashing phenomena, thermal radiation from pool fires, thermal radiation from fires involving jetting and flashing phenomena (jet fires), overpressure from vapor cloud ignitions, toxic gas dispersion, and boiling liquid expanding vapor explosions (BLEVEs) involving pressurized storage vessels should be included in an LNG plant's hazard evaluation.

H2. My LNG plant includes some toxic materials. What considerations should be given to accidental releases of these materials and the associated hazard modeling?

While the hazards associated with toxic substances at an LNG plant are not prescriptively covered in 49 CFR Part 193, their consideration is required by NFPA 59A-2001 Paragraph 2.1.1(d) (incorporated by reference in 49 CFR Part 193), which requires that all hazards that can affect the safety of the public or plant personnel be considered. Consideration of toxic hazards must include dispersion modeling appropriate for the toxic substance on site as well as incorporating safety measures of the design and operation of the facility.

Many toxic substances are regulated under the EPA's "Risk Management Program for Chemical Accidental Release Prevention" (RMP, 40 CFR 68) and OSHA's "Process Safety Management of Highly Hazardous Chemicals" (PSM, 29 CFR 1910.119). Compliance with EPA's RMP and OSHA's PSM regulations is a sufficient approach to comply with NFPA 59A Paragraph 2.1.1(d). PHMSA does not have authority to enforce EPA or OSHA regulations, but requires operator compliance with NFPA 59A Paragraph 2.1.1(d).

Applicants may propose alternative modeling methods to comply with NFPA 59A Paragraph 2.1.1(d) for toxic substances. The release scenario selection methodology should be consistent with the selection methodology for the single accidental leakage sources from LNG systems. When modeling the vapor dispersion of toxics, models should properly account for behavior of released materials. The ERPG-2 value (as specified by the RMP regulations) is the preferred endpoint to be used in the calculations. Because there are no specific exclusion zones that are to be defined for toxic materials, the offsite impacts at each proposed LNG plant will be evaluated on a case-by-case basis.

H3. Materials received, stored, or used at my LNG plant could generate overpressures from a vapor cloud explosion. What considerations should be given to vapor cloud explosions and the associated hazard modeling?

While explosion overpressure is not prescriptively covered in 49 CFR Part 193, its consideration is required by NFPA 59A-2001 Paragraph 2.1.1(d) (incorporated by reference in 49 CFR Part 193), which requires that all hazards that can affect the safety of the public or plant personnel be considered. Vapor cloud explosion modeling should involve consideration of vapor dispersion modeling results, evaluation of areas of confinement and congestion, and the potential reactivity of released materials. The use of the 1.0 psi overpressure endpoint is appropriate for explosion modeling, and is consistent with the EPA's "Risk Management Program for Chemical Accidental Release Prevention" (RMP, 40 CFR 68). Because there are no specific exclusion zones that are to be defined for explosion overpressure impacts, the offsite impacts at each proposed LNG plant will be evaluated on a case-by-case basis.

H4. What wind direction should be used in exclusion zone and other hazard calculations?

For most hazard calculations, the exclusion distance or hazard distance is calculated independent of wind direction. If the wind direction is important in the modeling methods used, the direction used should be toward the nearest property line. Additional wind directions may also need to be analyzed if the hazard could extend beyond other property lines or cause other unique hazards.

H5. Can an exclusion zone extend beyond the operator's LNG plant property line?

As long as the facility is in operation, the operator is responsible for assuring compliance with the limitations on land use within exclusion zones, according to the descriptions in NFPA 59A Sections 2.2.3.2, 2.2.3.3, and 2.2.3.4. For example, an exclusion zone that extends past a property line into a navigable body of water or onto a public road is typically acceptable. This may not hold true if that body of water contains a dock or pier that is not controlled by the operator of the LNG plant, or if another entity could erect a building or members of the public could assemble within the exclusion zone. It is possible to assure compliance by legal agreement with a property owner affected by the exclusion zone, such that the land use is restricted for the life of the LNG plant.

Revised: 8/12/15

Frequently Asked Questions

http://primis.phmsa.dot.gov:80/lng/faqs.htm

December 7, 2015

The FAQs may provide an acceptable solution(s). There may be other acceptable solutions. Some proposals require substantial technical justification to insure that any alternative approach provides an equivalent or higher level of safety. As this requires a case-by-case engineering evaluation, this may increase PHMSA's review time.

These FAQs are divided into four categories:

(G) General
(D) Design
(DS) Design Spill Definition
(H) Hazards and Hazards Modeling

(G) General

G1. The abundant supply of domestic natural gas is driving development of new ways to use, process, and transport LNG. Can PHMSA provide guidance as to which LNG facilities are regulated under 49 CFR Part 193?

The Pipeline Safety Statute codified in 49 U.S. Code § 60101, et seq, directs US DOT to establish and enforce standards for liquefied natural gas pipeline facilities. An LNG facility is a gas pipeline facility used for converting, transporting or storing liquefied natural gas.

Many LNG facilities are subject to the regulatory and enforcement authority of the Department of Transportation through PHMSA. A simple but not complete test to determine if an LNG facility is regulated under 49 CFR Part 193 is to identify both the source and the consumer of the LNG. The facility is regulated under 49 CFR Part 193 if the LNG facility either receives from or delivers to a 49 CFR Part 192 pipeline.

49 CFR Part 193 does not apply to:

1. LNG facilities used by ultimate consumers of LNG or natural gas.
2. LNG facilities used in the course of natural gas treatment or hydrocarbon extraction that do not store LNG.
3. In marine cargo transfer systems and associated facilities, any matter other than siting pertaining to the system or facilities between the marine vessel and the last manifold (or, in the absence of a manifold, the last valve) located immediately before a storage tank.
4. Any LNG facility located in navigable waters (as defined in Section 3(8) of the Federal Power Act (16 U.S.C. 796(8)).

Operators should assume an LNG facility used in the transportation of gas by a 49 CFR Part 192 pipeline is regulated under 49 CFR Part 193 unless specifically exempted in Section 193.2001(b). LNG facilities may be regulated by PHMSA even though they are not regulated by the FERC. The 'ultimate consumer' provision provides a very limited exemption from 49 CFR Part 193. PHMSA interpretation # PI-10-0025 provides guidance. Here is an excerpt:

During the rulemaking that led to the adoption of § 193.2001(b)(1), OPS explained that the intent of that provision was to create an exception for "an LNG facility used by the ultimate consumer of the product". Likewise, in responding to a series of questions from a congressional committee, OPS stated that the exception in § 193.2001(b)(1), was designed for "small" facilities which are "generally located in industrial plants ... [to] serve as a supply of energy or feedstock for the plant." Unlike these examples, the Maine LMF facilities would be used to produce LNG for sale and distribution by truck, not solely for onsite consumption. Therefore, OPS concludes that your client's facilities would not qualify for the end-user exception in § 193.2001(b)(1).

G2. What agency or agencies have regulatory authority over the siting of LNG facilities?

There are more than 110 liquefied natural gas (LNG) facilities operating in the U.S. performing a variety of services. Most of these facilities store LNG for "peak shaving," where the LNG is vaporized and transported in gas transmission or gas distribution pipelines for periods of peak demand. There is significant growth in the number of facilities producing LNG as a transportation vehicle fuel for trucks, buses, trains, and ships. Depending on the location and use, several Federal agencies and State utility regulatory agencies may regulate an LNG facility.

For LNG import and export facilities located onshore, three Federal agencies share oversight for safety and security: the Federal Energy Regulatory Commission (FERC), the U.S. Coast Guard, and the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA). Under Section 3 of the Natural Gas Act of 1938, FERC is responsible for authorizing the siting and construction of onshore and near-shore LNG import or export facilities. Under Section 7 of the Natural Gas Act of 1938, FERC also issues certificates of public convenience and necessity for LNG facilities engaged in interstate natural gas transportation by pipeline. As required by the National Environmental Policy Act (NEPA), FERC prepares NEPA analyses for proposed LNG facilities under its jurisdiction. The Coast Guard has authority over the safety of LNG vessels and the marine transfer area, conducting Waterway Suitability Assessments to address navigation safety and port security issues associated with LNG ship traffic. PHMSA has authority to establish and enforce safety standards for onshore LNG facilities.

PHMSA's regulations for LNG facilities appear in Title 49, Part 193 of the Code of Federal Regulations (CFR). LNG facility applicants, when applying to FERC, are required to identify how their proposed facility would meet the siting requirements of 49 CFR Part 193. FERC consults with its cooperating agencies, including PHMSA, as needed. Once FERC approves a project and the applicant moves forward in the process, PHMSA inspects sites during and after construction, and during facility operation, and is responsible for taking enforcement action under Part 193 if necessary.

G3. As an operator, how do I submit an application to install a FERC regulated LNG facility?

The FERC is responsible for authorizing the siting and construction of onshore and near-shore LNG import or export facilities and LNG facilities engaged in interstate natural gas transportation by pipeline. As an operator of one of these types of facilities, you must coordinate with the FERC in the development of the Resource Reports required for the FERC application process. Information on Resource Reports 11 & 13, which deals with the engineering detail of the LNG facility, can be found in 18 CFR 380.12 (m) & (o).

G4. What types of LNG facilities require information submittal?

If an LNG facility requires FERC review and siting approval, PHMSA as a cooperating agency will require detailed information as described in these FAQs. Please refer to Subpart A of Part 193 for scope and applicability of PHMSA's regulations. There are regulations in Part 193 pertaining to siting, design, construction, equipment, maintenance, personnel qualifications and training, fire protection, and security. If the operator has questions or needs further guidance on the applicability of Part 193 to the facility in question, then the operator may contact PHMSA headquarters or the PHMSA Regional Offices. PHMSA's regional contact information is located here, or you may contact PHMSA's Director of Engineering as noted below under FAQ #G6.

G5. Does PHMSA have an application or permitting process for new or modified LNG facilities that are subject to the jurisdiction of Part 193 but does not require FERC review?

PHMSA does not require an application process and does not have authority for permitting LNG facilities. PHMSA requires LNG operators submit information to the National Registry of Pipeline and LNG Operators database 60 days prior to commencing construction when the project cost are $10 million or more. See FAQ #G10 below for more information.

LNG operators may be required to submit an application to the Federal Energy Regulatory Agency (FERC) or the appropriate state agency. Operators must notify the State Pipeline Safety Agencies at least 2 weeks prior to the installation of portable LNG facilities and provide information prescribed in § 193.2019 (b).

Determining how to comply with 49 CFR 193 is the responsibility of the operator. PHMSA is available to answer your questions. Please contact Ken Lee, Director, Engineering and Research Division (202) 366-2694 or by email kenneth.lee@dot.gov.

G6. Since PHMSA is a cooperating agency in the FERC siting process, do I need to provide anything directly to PHMSA in order to help expedite the application process?

Yes. If a facility is subject to Part 193 (see reply to FAQ #G3 above), then in order for PHMSA to perform an in-depth review and analysis, you should copy and forward specific items for evaluation. You should send all application materials directly to FERC, but you should also submit to PHMSA hard and digital copies of the documents noted in these FAQs to aid PHMSA in its review. Review of your application will be delayed unless you promptly submit to PHMSA substantially complete application materials. Please also be aware that PHMSA will need detailed materials without any redaction, regardless of security sensitive or proprietary information, in order to conduct a full review. If you believe your materials are security sensitive or proprietary in any way, please mark them accordingly.

Materials noted below should be addressed to:

U.S. Department of Transportation
Pipeline & Hazardous Materials Safety Administration
Kenneth Lee – Director
Engineering and Research Division
East Building, Room E22-334
1200 New Jersey Avenue, SE
Washington, DC 20590
Telephone: (202) 366-2694
Email: kenneth.lee@dot.gov

G7. What specific items should be sent to PHMSA?

The applicant should submit a Design Spill Package directly to PHMSA to aid in the review process. Detailed engineering materials are required as part of the Design Spill Package.

The Design Spill Package should include:

a. Project description, background, purpose and details describing the proposed facility;
b. Hazard reports, including any attachments and referenced reports;
c. Facility location map(s), topography map(s), and site aerial photography;
d. Engineering drawings including an overall plot plan showing the project's property boundary and unit plot plans for each process area or system showing the location and elevation of major equipment. Each area and piece of equipment should be clearly labeled. The unit plot plans should be detailed enough to allow for measurement of distances between various components with a reasonable degree of accuracy. The smallest scale submitted should be no smaller than 1-inch to 100-feet (1:1200);
e. Piping and instrument drawings (P&ID;);
f. Process Flow Diagrams (PFD);
g. Heat and Material Balance Sheets (H&MB;);
h. Piping and Equipment Inventory Table of LNG plant components;
i. Pump and compressor curves for pumps and compressors used for hazardous fluid service (as available);
j. List of all intended direct discharge points to atmosphere (this should include vents and drains);
k. Sketch on plot plan showing expected locations and elevations of major potential single accidental leakage sources;
l. Dimensions, capacities, and thermal properties for any impoundments associated with this project;
m. Design details for vapor barriers;
n. Input and output summary parameters for computer program simulations, (i.e. PHAST) should be included with model submissions. This information should include input and output files and reports.

If additional information is required, PHMSA will work with the applicant on additional information submittals.

G8. After I submit information to PHMSA, how long will the review process take?

The duration of the review process varies. There are a variety of factors which influence the timeline for review and approval, including the volume of previously submitted applications, where the applicant is in the siting process, and the completeness of the submitted information. PHMSA will acknowledge receipt of the application and will begin the review process. PHMSA will contact the applicant during the review process to resolve any outstanding needs or questions.

G9. After I submit the required information to PHMSA, what information do I need to file on the FERC docket?

For those projects under FERC jurisdiction, all information submitted to PHMSA should be filed on the FERC docket. PHMSA will work with the applicant to review the information. If revisions or edits are necessary, the applicant will be instructed to file an addendum to the FERC docket.

G10. A FERC regulation (18 CFR § 385.2201) prohibits off-the-record communications in a contested, on-the-record proceeding. The rule is designed to limit communications between a "decisional employee" at FERC and persons outside the Commission. How do FERC's restrictions on ex parte communication affect PHMSA's communications with LNG project applicants?

The purpose of the rule is to ensure the integrity and fairness of the Commission's decisional process, and to prevent off-the-record communications relative to the merits of a Commission proceeding between FERC decisional employees and entities outside of the Commission. Generally, communications regarding Part 193 compliance between PHMSA and a party before the Commission do not violate FERC's ex parte rules. However, PHMSA takes care to not act as a conduit for otherwise unpermitted communications. Some communication between PHMSA and a facility applicant is expected, but PHMSA restricts those communications to matters that FERC has explicitly referred to PHMSA. In accordance with the FERC's public disclosure requirements and FERC's responsibilities under its ex parte regulations, PHMSA, as a cooperating agency, cannot release pre decisional information related to the NEPA analysis (such as working drafts of NEPA documents and PHMSA comments on those working drafts).

If PHMSA needs additional information from an applicant to resolve a matter that FERC has referred to us, PHMSA will advise FERC and the applicant of what additional information is needed and request that it be submitted to FERC's docket.

G11. How do operators notify PHMSA that construction of an LNG facility will be commencing?

The Operator Registry Notification is used by operators to report new construction, asset-changing or program-changing events associated with LNG facilities. Each operator of an LNG plant or LNG facility is required to submit notification of specified events to PHMSA in accordance with § 191.22(c) either 60 days or more before the planned occurrence or 60 days or less after the occurrence, as specified in these regulations.

Specified events include:

- Change in the name of the operator of an existing LNG plant or LNG facility;
- Change in the entity (e.g., company, municipality) responsible for operating an LNG facility;
- Change in the primary entity responsible (i.e., with an assigned operator identification (OPID) number) for managing or administering a safety program required by 49 CFR 193 covering pipeline facilities operated under multiple OPIDs;
- Acquisition or divestiture of an existing LNG plant or LNG facility subject to 49 CFR 193;
- Construction of a new LNG plant or LNG facility;

Notifications must be made online via the PHMSA portal, using assigned user name and password, unless an alternate method is approved.

LNG Construction Report – Notification Type J

G12. What are the siting requirements for small LNG facilities that have an aggregate storage capacity of 70,000 gallons or less on one site?

The writer asks, "Part 193 has requirements for thermal radiation exclusion and vapor-gas dispersion exclusion zones that are required for *each* LNG container and transfer system, but NFPA 59A, 2001 edition has Table 2.2.4.1 *Distances from Impoundment Areas to Buildings and Property Lines* for small LNG facilities with total onsite storage capacity of 70,000 gallons LNG or less. Does NFPA 59A, 2001 edition, Chapter 2, Plant Siting and Layout, Paragraph 2.2.3.7 which allows use of Table 2.2.4.1 'Distances from Impoundment Areas to Buildings and Property Lines' *conflict* with Part 193 Subpart B – Siting Requirements?"

Part 193 siting requirements include the determination of exclusion zones, areas in which the operator or a government agency legally controls all activities. The exclusion zones are determined by complying with § 193.2057 *Thermal radiation protection* and § 193.2059 *Flammable vapor-gas dispersion protection*. These sections incorporate by reference NFPA 59A Paragraph 2.2.3.2 (thermal radiation distance) and Paragraphs 2.2.3.3 and 2.2.3.4 (vapor dispersion distance). NFPA 59A Paragraph 2.2.3.7 is not provided as an alternative to § 193.2057 and § 193.2059 for permanent facilities.

Under § 193.2019, mobile and temporary LNG facilities need not meet the requirements of Part 193 (including Sections 193.2057 and 193.2059) if they comply with the applicable sections of NFPA 59A that is incorporated by reference. NFPA 59A Paragraph 2.3.4 covers the requirements for such facilities. 2.3.4(g) references Table 2.2.4.1 for the spacing guidelines at mobile and temporary facilities. When Table 2.2.4.1 is used for compliance with Paragraph 2.3.4 (g), the aggregate capacity of the multiple LNG containers on the temporary site is to be used to determine facility spacing.

(D) Design

D1. What wind speed should be used in LNG facility equipment design calculations?

Wind forces are addressed in 49 CFR § 193.2067, which requires that LNG facilities be designed to withstand the direct effect of wind forces without loss of structural or functional integrity. Structural engineering design is typically performed using 3-second gust wind speeds in miles-per-hour (mph).

For shop fabricated containers of LNG or other hazardous fluids with a capacity of not more than 70,000 gallons, the wind forces at the location of the specific facility must be based on applicable wind load data in ASCE/SEI 7-05.

For all other LNG facilities, the wind forces at the location of the specific facility must be based on one of the following:

a. an assumed sustained wind velocity of not less than 150 MPH; or
b. a sustained wind velocity of less than 150 MPH that is justified by adequate supportive data and found acceptable by the Administrator; or
c. the most critical combination of wind velocity and duration, with respect to the effect on the structure, having a probability of exceedance in a 50-year period of 0.5 percent or less, if adequate wind data are available and the probabilistic methodology is reliable.

For most structural engineering design calculations, the sustained wind velocity is converted to 3-second gust wind speed using a conservative method based on sound engineering principles. The Durst curve is an acceptable conversion method in ASCE/SEI 7-05, Chapter C6. Using this method, a sustained wind velocity of 150 mph is equivalent to a 183 mph 3-second gust. Applicants should also design all facilities to meet all applicable local or state building codes.

D2. To what parts of the facility does § 193.2067(b)(2) apply?

This paragraph applies to all LNG facilities other than those that are described in § 193.2067(b)(1). The term "LNG facility" is defined in 49 CFR § 193.2007. The parts of the LNG plant considered for compliance with this design requirement include all parts used when liquefying natural gas or transferring, storing, or vaporizing liquefied natural gas. This includes piping and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation.

D3. Should the wind speed design criteria of 193.2067 be applied to vapor barriers at the LNG plant?

Since vapor barriers are installed for the purpose of reducing the extent of exclusion zones, they are a part of the LNG facilities and subject to the regulatory wind speed requirements. Vapor barriers must be functional while the LNG facility is in operation.

D4. Can vacuum jacketed piping be used in an LNG plant and may the outer pipe be used for LNG impoundment?

The applicant must fully document any application of vacuum jacketed pipe (VJP) or vacuum insulated pipe (VIP). The design details of the piping as well as the locations where it is to be used must be provided. In cases where the VJP or VIP may affect the prescribed design spills, impoundment determinations, or other hazard calculations, the applicant must fully justify the position and approach being taken. PHMSA will review these applications on a case-by-case basis, and a special permit (see 49 CFR Section 190.341) may be required.

(DS) Design Spill Determination

DS1. PHMSA reviews the design criteria for design spills on a case-by-case basis to determine compliance with Part 193. What information is required to assist PHMSA in its determination of the design spill criteria acceptable for use?

Applicants must provide a piping and equipment inventory table of LNG plant components in hazardous or flammable fluid service. The piping and equipment inventory table should be submitted in Excel (*.XL*) format. Separate tabs or lists should be used for each type of hazardous fluid, as well as a separate tab or list to present all of the final design spill selections.

The table should include the following information:

a. Line segment or component number to identify potential design spill;
b. Hazardous fluid service (LNG, natural gas, refrigerants (such as ammonia, propane, ethane, mixed refrigerant), natural gas liquids or gas condensate, hydrogen sulfide, benzene, etc.) for each component;
c. General plant area or service (e.g. liquefaction train, refrigerant storage, marine area, etc.), unless the entire project is confined to one area;
d. Unit plot plan drawing number reference(s) for each component;
e. Beginning point location (e.g., exchanger outlet flange) for each line;
f. Ending point location (e.g., pump suction nozzle) for each line;
g. P&IDs and drawing number reference(s) for each component;
h. Piping line designation or equipment tag number on P&ID;
i. Pipe diameter or pipe size, volume of container, or size of equipment;
j. Length of piping (feet and meters); or number of components (each);
k. Maximum connection diameter in the piping segment;
l. Failure type or mode selected from the failure rate table;
m. Corresponding nominal failure rates per meter or unit;
n. Calculated failure rate based on pipe length or number of units and failure rates per meter or unit listed in the failure rate table;
o. Comparison of calculated failure rate to a failure rate criterion of 3x10-5 failures per year;

p. Process or storage conditions (e.g., fluid phase (liquid or vapor); density (lb/ft3); pressure (psig); temperature (°F); flow rate, (lb/hr); composition of mixed refrigerants, NGL/Condensates, acid gas);
q. Process flow diagram and corresponding heat and material balance stream number;
r. Heat and material design case (e.g., rich, lean, average, etc.);
s. Calculated equivalent hole size based on failure modes listed in the failure rate table; and
t. Calculated design spill flow rates.
u. Design spills selected with release duration, de-inventory duration, height, direction, orientation, rainout percentage, flashing and jetting vapor mass flow rate, pool vaporization mass flow rate, and total vapor mass flow rate

DS2. What sorts of pipe, equipment, and containers should be included on the piping and equipment inventory table?

Components that should be considered to fail in the analysis for determination of the single accidental leakage source are those containing hazardous or flammable fluids and are listed on the Failure Rate Table. The table must include pipe of 2-inch diameter and larger size, valves, gaskets, expansion joints, truck transfer hoses, truck transfer arms, ship transfer arms, pumps, compressors, process vessels, columns, heat exchangers, condensers, and storage tanks.

DS3. 49 CFR 193 requires that design spills for an LNG plant be selected according to NFPA 59A-2001 Paragraph 2.2.3.5. NFPA 59A requires the evaluation of accidental flow from "any single accidental leakage source" (SALS) but does not define this term. How should I select SALS events in an LNG plant?

For piping and equipment that handle LNG, flammable refrigerants, toxic components, or any other hazardous fluid, release sources may be chosen using the following guidelines. The SALS selection methodology is applied to determine the maximum hole sizes of interest for the most significant releases of each hazardous fluid in each portion of the LNG plant. (The SALS selections are one component of design spill definition. Please refer to other FAQs for additional design spill definition topics.)

a. For all piping and equipment (including transfer hoses and arms), the failure rate table should be applied to determine if the 3×10^{-5} per year failure rate criterion is equaled or exceeded; and,
b. For all piping, the failure rate table is applied to a piping segment (i.e., length of pipe) and the hole size is chosen based on equaling or exceeding the 3×10^{-5} per year failure rate criterion. The following rules should be applied to piping segments:
    1. Piping segments should be selected to begin and end at pieces of equipment and include all tees, loops, and branches; and
    2. A principle to be applied for piping segment begin/end locations is at points where the process conditions change significantly (typically temperature, pressure, or composition); and
    3. Piping segments should not be initiated or terminated at valves (e.g. pressure regulating valves, flow control valves, etc.), piping spec changes, flange connections, flow meters, reducers, piping fittings, or other piping appurtenances; and
    4. Piping segment length should be based on piping isometrics but may be based on engineering estimates of the piping path, accounting for vertical distances as well as horizontal distances.
c. For piping connections less than 6 inches in diameter, a full-bore rupture (guillotine failure) is assumed at the point of connection to the equipment item or piping. Small diameter piping is typically used for connections to equipment (e.g., storage tanks, vessels, heat exchangers, pumps, etc.) or to piping as drain lines, vent lines, nitrogen purge lines, PSV connections, valve bypass connections, instrument connections, etc.

d. Regardless of the results obtained by the failure rate table or connections approach above, a minimum 2-inch hole should be considered at any location along any piping of 2 inches or larger diameter.

DS4. Can a fractional time of use be applied when determining SALS events with a probabilistic spill selection methodology?

When determining the design spill through the use of a probabilistic spill selection method, a time-of-use factor may be applied to some piping or equipment groups based on their expected use. For groups that have a fractional time of use other than 1.0 (100% use), the applicant must be able to demonstrate that the group can be isolated, purged, instrumented, maintained, and continually documented in such a way that the fractional time of use is traceable. In groups that operate continually but in more than one mode, each mode must be considered as a potential design spill source and the sum of the fractional times of use in each mode must equal 1.0 (100% use). An example of this would be a loading/unloading line that moves a high mass rate when loading or unloading LNG, but moves a much smaller mass rate when recirculating to keep the line cooled down.

DS5. Is the largest size hole always used as the hole size in release modeling?

Not necessarily. For any defined maximum hole size, the applicant must demonstrate that that the hole size selected produces the greatest vapor dispersion distance when accounting for the mechanisms of jetting, flashing, aerosol formation, and rain-out. If a smaller hole size creates a larger vapor dispersion hazard distance, that smaller hole size should be used to define the design spill event. This applies to all single accidental leakage sources, including failures at piping, piping connections, and all other equipment (e.g., transfer hoses, vessels, heat exchangers, pumps, valves, flanges, etc.).

DS6. What are the proper release height and orientation to use for a design spill?

For each design spill identified, release height and orientation should be selected to define the largest vapor dispersion hazard distance while properly characterizing the release scenario. If an applicant can show that only certain release orientations are possible based on the piping connections and direction of the piping (e.g., vertically upward for connections to relief valve inlet piping, vertically downward for gravity drain connections, and downward for shrouded piping) then a specific orientation may be used in the modeling. All other piping and equipment failures must consider all horizontal and vertical directional orientations.

DS7. How are release locations defined?

For connection failures, the release location can be identified at the specific point of connection in the LNG plant. For piping segments to which the failure rate table has been applied, the selected hole can occur at any location along the piping segment. If vapor barriers, shrouds, or pipe-in-pipe designs are used to reduce the vapor dispersion distance, locations potentially not impacted by the vapor barrier, shroud, or pipe-in-pipe should also be selected.

DS8. How do I determine the process conditions to evaluate for hazard modeling?

Process conditions should be based on heat and material balance modes of operation and design cases (e.g., rich, lean, average, etc.) that produce the worst case dispersion results from flashing and jetting and liquid releases. The leakage sources from branch connections should be considered using the potential operational conditions along the pipe as well as the potential operational conditions that could be experienced at or near the branch pipe connection to a main process line. In cases that would reduce the back pressure on pump(s) or compressor(s), the flow rates should consider the potential increased pump or compressor flow determined by the pump and compressor curve(s) as detailed in D10 and also consider the decrease in temperature from depressurization.

DS9. Is it permissible to use spill duration of less than 10 minutes for design spill calculations?

For design spills other than those from LNG containers, the event is defined in NFPA 59A to last "for 10 minutes or a shorter time based on demonstrable surveillance and shutdown provisions acceptable to the authority having jurisdiction." Demonstrable surveillance and shutdown should include the time required to detect that the spill is occurring, the time to alert operators to this condition, the time required for operators to take action, and the time for the system to fully respond to the shutdown action that is initiated, including any valve closure times. In this case, the applicant should provide a detailed justification or demonstrate that a maximum or steady state dispersion distance has already been reached by the shorter time.

In cases where a system may deplete its inventory in less than 10 minutes, a release duration of less than 10 minutes may be used. In this case, the applicant should provide a detailed justification or demonstrate that a maximum or steady state dispersion distance has already been reached by the shorter time.

DS10. What considerations should be given to system inventory in the design spill definition?

The release modeling should account for the available system inventory (including pipework, process vessels, and other process equipment), the normal flow of fluid into the system, and the demonstrable surveillance and shutdown provisions that may apply. The release modeling should also continue (even beyond 10 minutes) until the available system inventory is depleted; available system inventory may be modified during the event by valve closures. For systems that rely on isolation by emergency shutdown valves, the valves must be protected from failure, including fire and external impacts.

If the event the duration would potentially be greater than 10 minutes, release and dispersion modeling should continue after 10 minutes unless a release is demonstrated to reach its furthest vapor dispersion extent within 10 minutes.

DS11. Do I need to consider pump run-out in release scenario calculations?

Yes. Applicants should use pump run-out (greater flow than in normal pump flow operations) in failure calculations if the pump design allows increases in flow as the discharge pressure is reduced. Pump run-out parameters are presented by the pump manufacturer as a pump curve that shows flow increasing as the discharge pressure decreases. If pump run-out flows are not known at the time of submittal, engineering estimates may be employed provisionally.

DS12. Should multiple pumps be considered when calculating the greatest flow from a spill to size impoundments?

Where the greatest flow is potentially fed from multiple pumps, calculate the flow assuming that all pumps are running at possible pump run-out conditions, unless a mechanical interlock or passive preventive measure is installed that prevents all pumps from running concurrently.

(H) Hazards and Hazards Modeling

H1. Other than the flammable vapor dispersion and thermal radiation from hazards associated with LNG, what other hazards should be evaluated in the siting analysis for an LNG plant?

According to NFPA 59A-2001 Paragraph 2.1.1(d), (incorporated by reference in 49 CFR Part 193), all hazards that can affect the safety of the public or plant personnel are to be considered. In addition to LNG, the applicant should consider hazards associated with flammable gases, flammable refrigerants, flammable or combustible liquids, or acutely toxic materials. If present at the LNG plant, hazards including vapor dispersion from liquid pools, vapor dispersion from jetting and flashing phenomena, thermal radiation from pool fires, thermal radiation from fires involving jetting and flashing phenomena (jet fires), overpressure from vapor cloud ignitions, toxic gas dispersion, and boiling liquid expanding vapor explosions (BLEVEs) involving pressurized storage vessels should be included in an LNG plant's hazard evaluation.

H2. My LNG plant includes some toxic materials. What considerations should be given to accidental releases of these materials and the associated hazard modeling?

While the hazards associated with toxic substances at an LNG plant are not prescriptively covered in 49 CFR Part 193, their consideration is required by NFPA 59A-2001 Paragraph 2.1.1(d) (incorporated by reference in 49 CFR Part 193), which requires that all hazards that can affect the safety of the public or plant personnel be considered. Consideration of toxic hazards must include dispersion modeling appropriate for the toxic substance on site as well as incorporating safety measures of the design and operation of the facility.

Many toxic substances are regulated under the EPA's "Risk Management Program for Chemical Accidental Release Prevention" (RMP, 40 CFR 68) and OSHA's "Process Safety Management of Highly Hazardous Chemicals" (PSM, 29 CFR 1910.119). Compliance with EPA's RMP and OSHA's PSM regulations is a sufficient approach to comply with NFPA 59A Paragraph 2.1.1(d). PHMSA does not have authority to enforce EPA or OSHA regulations, but requires operator compliance with NFPA 59A Paragraph 2.1.1(d).

Applicants may propose alternative modeling methods to comply with NFPA 59A Paragraph 2.1.1(d) for toxic substances. The release scenario selection methodology should be consistent with the selection methodology for the single accidental leakage sources from LNG systems. When modeling the vapor dispersion of toxics, models should properly account for behavior of released materials. The ERPG-2 value (as specified by the RMP regulations) is the preferred endpoint to be used in the calculations. Because there are no specific exclusion zones that are to be defined for toxic materials, the offsite impacts at each proposed LNG plant will be evaluated on a case-by-case basis.

H3. Materials received, stored, or used at my LNG plant could generate overpressures from a vapor cloud explosion. What considerations should be given to vapor cloud explosions and the associated hazard modeling?

While explosion overpressure is not prescriptively covered in 49 CFR Part 193, its consideration is required by NFPA 59A-2001 Paragraph 2.1.1(d) (incorporated by reference in 49 CFR Part 193), which requires that all hazards that can affect the safety of the public or plant personnel be considered. Vapor cloud explosion modeling should involve consideration of vapor dispersion modeling results, evaluation of areas of confinement and congestion, and the potential reactivity of released materials. The use of the 1.0 psi overpressure endpoint is appropriate for explosion modeling, and is consistent with the EPA's "Risk Management Program for Chemical Accidental Release Prevention" (RMP, 40 CFR 68). Because there are no specific exclusion zones that are to be defined for explosion overpressure impacts, the offsite impacts at each proposed LNG plant will be evaluated on a case-by-case basis.

H4. What wind direction should be used in exclusion zone and other hazard calculations?

For most hazard calculations, the exclusion distance or hazard distance is calculated independent of wind direction. If the wind direction is important in the modeling methods used, the direction used should be toward the nearest property line. Additional wind directions may also need to be analyzed if the hazard could extend beyond other property lines or cause other unique hazards.

H5. Can an exclusion zone extend beyond the operator's LNG plant property line?

As long as the facility is in operation, the operator is responsible for assuring compliance with the limitations on land use within exclusion zones, according to the descriptions in NFPA 59A Sections 2.2.3.2, 2.2.3.3, and 2.2.3.4. For example, an exclusion zone that extends past a property line into a navigable body of water or onto a public road is typically acceptable. This may not hold true if that body of water contains a dock or pier that is not controlled by the operator of the LNG plant, or if another entity could erect a building or members of the public could assemble within the exclusion zone. It is possible to assure compliance by legal agreement with a property owner affected by the exclusion zone, such that the land use is restricted for the life of the LNG plant.

H6. In addition to DEGADIS 2.1 and FEM3A, Section 193.2059 Flammable vapor dispersion protection provides for the use of alternate models approved by US DOT PHMSA. What other models have been approved?

US DOT PHMSA has approved two additional models for the determination of vapor dispersion exclusion zones: FLACS 9.1 Release 2 (October 7, 2011) and PHAST-UDM Version 6.6 and 6. 7 (October 7, 2011). Each model has been validated for use in certain conditions in accordance with the Model Evaluation Protocol (MEP) as described in M. J. Ivings et al., Evaluating Vapor Dispersion Models for Safety Analysis of LNG Facilities Research Project: Technical Report (April 2007) (available at http://www.nfpa.org).

For detailed information regarding the conditions for which the models were validated, see PHMSA's final decision at:

FLACS http://www.regulations.gov/#!docketDetail;D=PHMSA-2011-0101

PHAST http://www.regulations.gov/#!docketDetail;D=PHMSA-2011-0075

H7. Does US DOT PHMSA prescribe source term models for flammable vapor dispersion modeling?

While PHMSA does not prescribe or approve source term models, the source term model must have a creditable scientific basis and must not ignore any phenomena that can influence vapor formation during discharge from containment, conveyance to an impoundment, and retention within the impoundment. In July, 2010 PHMSA communicated in interpretation PI-10-0021 that the SOURCE5 model does not satisfy the PHMSA requirements for a source term model. The interpretation can be viewed at: http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=319134025ed5b210VgnVCM1000001ecb7898RCRD.

H8. Can mitigation measures be used in exclusion zone and other hazard calculations?

For most hazard calculations, passive mitigation measures are inherently acceptable, provided that their design and implementation can be technically supported and that they do not introduce other harmful consequences.

Active or procedural mitigation measures are generally not included exclusion zone or hazard zone calculations. However, PHMSA will review the proposed inclusion of such measures on a case-by-case basis, provided that proper supporting technical justification and documentation is submitted.

Revised: 12/7/15

Frequently Asked Questions

https://www.phmsa.dot.gov/faqs/liquefied-natural-gas

January 10, 2017

(G) General

G1. The abundant supply of domestic natural gas is driving development of new ways to use, process, and transport LNG. Can PHMSA provide guidance as to which LNG facilities are regulated under 49 CFR Part 193?

The Pipeline Safety Statute codified in 49 U.S. Code § 60101, et seq, directs US DOT to establish and enforce standards for liquefied natural gas pipeline facilities. An LNG facility is a gas pipeline facility used for converting, transporting or storing liquefied natural gas.

Many LNG facilities are subject to the regulatory and enforcement authority of the Department of Transportation through PHMSA. A simple but not complete test to determine if an LNG facility is regulated under 49 CFR Part 193 is to identify both the source and the consumer of the LNG. The facility is regulated under 49 CFR Part 193 if the LNG facility either receives from or delivers to a 49 CFR Part 192 pipeline.

49 CFR Part 193 does not apply to:

1. LNG facilities used by ultimate consumers of LNG or natural gas.
2. LNG facilities used in the course of natural gas treatment or hydrocarbon extraction that do not store LNG.
3. In marine cargo transfer systems and associated facilities, any matter other than siting pertaining to the system or facilities between the marine vessel and the last manifold (or, in the absence of a manifold, the last valve) located immediately before a storage tank.
4. Any LNG facility located in navigable waters (as defined in Section 3(8) of the Federal Power Act (16 U.S.C. 796(8)).

Operators should assume an LNG facility used in the transportation of gas by a 49 CFR Part 192 pipeline is regulated under 49 CFR Part 193 unless specifically exempted in Section 193.2001(b). LNG facilities may be regulated by PHMSA even though they are not regulated by the FERC. The 'ultimate consumer' provision provides a very limited exemption from 49 CFR Part 193. PHMSA interpretation # PI-10-0025 provides guidance. Here is an excerpt:

> *During the rulemaking that led to the adoption of § 193.2001(b)(1), OPS explained that the intent of that provision was to create an exception for "an LNG facility used by the ultimate consumer of the product". Likewise, in responding to a series of questions from a congressional committee, OPS stated that the exception in § 193.2001(b)(1), was designed for "small" facilities which are "generally located in industrial plants ... [to] serve as a supply of energy or feedstock for the plant." Unlike these examples, the Maine LMF facilities would be used to produce LNG for sale and distribution by truck, not solely for onsite consumption. Therefore, OPS concludes that your client's facilities would not qualify for the end-user exception in § 193.2001(b)(1).*

G2. What agency or agencies have regulatory authority over the siting of LNG facilities?

There are more than 110 liquefied natural gas (LNG) facilities operating in the U.S. performing a variety of services. Most of these facilities store LNG for "peak shaving," where the LNG is vaporized and transported in gas transmission or gas distribution pipelines for periods of peak demand. There is significant growth in the number of facilities producing LNG as a transportation vehicle fuel for trucks, buses, trains, and ships. Depending on the location and use, several Federal agencies and State utility regulatory agencies may regulate an LNG facility.

For LNG import and export facilities located onshore, three Federal agencies share oversight for safety and security: the Federal Energy Regulatory Commission (FERC), the U.S. Coast Guard, and the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA). Under Section 3 of the Natural Gas Act of 1938, FERC is responsible for authorizing the siting and construction of onshore and near-shore LNG import or export facilities. Under Section 7 of the Natural Gas Act of 1938, FERC also issues certificates of public convenience and necessity for LNG facilities engaged in interstate natural gas transportation by pipeline. As required by the National Environmental Policy Act (NEPA), FERC prepares NEPA analyses for proposed LNG facilities under its jurisdiction. The Coast Guard has authority over the safety of LNG vessels and the marine transfer area, conducting Waterway Suitability Assessments to address navigation safety and port security issues associated with LNG ship traffic. PHMSA has authority to establish and enforce safety standards for onshore LNG facilities.

PHMSA's regulations for LNG facilities appear in Title 49, Part 193 of the Code of Federal Regulations (CFR). LNG facility applicants, when applying to FERC, are required to identify how their proposed facility would meet the siting requirements of 49 CFR Part 193. FERC consults with its cooperating agencies, including PHMSA, as needed. Once FERC approves a project and the applicant moves forward in the process, PHMSA inspects sites during and after construction, and during facility operation, and is responsible for taking enforcement action under Part 193 if necessary.

G3. As an operator, how do I submit an application to install a FERC regulated LNG facility?

The FERC is responsible for authorizing the siting and construction of onshore and near-shore LNG import or export facilities and LNG facilities engaged in interstate natural gas transportation by pipeline. As an operator of one of these types of facilities, you must coordinate with the FERC in the development of the Resource Reports required for the FERC application process. Information on Resource Reports 11 & 13, which deals with the engineering detail of the LNG facility, can be found in 18CFR380.12(m)&(o).

G4. What types of LNG facilities require information submittal?

If an LNG facility requires FERC review and siting approval, PHMSA as a cooperating agency will require detailed information as described in these FAQs. Please refer to Subpart A of Part 193 for scope and applicability of PHMSA's regulations. There are regulations in Part 193 pertaining to siting, design, construction, equipment, maintenance, personnel qualifications and training, fire protection, and security. If the operator has questions or needs further guidance on the applicability of Part 193 to the facility in question, then the operator may contact PHMSA headquarters or the PHMSA Regional Offices. PHMSA's regional contact information is located here, or you may contact PHMSA's Director of Engineering as noted below under FAQ #G6.

G5. Does PHMSA have an application or permitting process for new or modified LNG facilities that are subject to the jurisdiction of Part 193 but does not require FERC review?

PHMSA does not require an application process and does not have authority for permitting LNG facilities. PHMSA requires LNG operators submit information to the National Registry of Pipeline and LNG Operators database 60 days prior to commencing construction. See FAQ #G10 below for more information.

LNG operators may be required to submit an application to the Federal Energy Regulatory Agency (FERC) or the appropriate state agency. Operators must notify the State Pipeline Safety Agencies at least 2 weeks prior to the installation of portable LNG facilities and provide information prescribed in § 193.2019 (b).

Determining how to comply with 49 CFR 193 is the responsibility of the operator. PHMSA is available to answer your questions. Please contact Ken Lee, Director, Engineering and Research Division (202) 366-2694 or by email kenneth.lee@dot.gov.

G6. Since PHMSA is a cooperating agency in the FERC siting process, do I need to provide anything directly to PHMSA in order to help expedite the application process?

Yes. If a facility is subject to Part 193 (see reply to FAQ #G3 above), then in order for PHMSA to perform an in-depth review and analysis, you should copy and forward specific items for evaluation. You should send all application materials directly to FERC, but you should also submit to PHMSA hard and digital copies of the documents noted in these FAQs to aid PHMSA in its review. Review of your application will be delayed unless you promptly submit to PHMSA substantially complete application materials. Please also be aware that PHMSA will need detailed materials without any redaction, regardless of security sensitive or proprietary information, in order to conduct a full review. If you believe your materials are security sensitive or proprietary in any way, please mark them accordingly.

Materials noted below should be addressed to:

U.S. Department of Transportation
Pipeline & Hazardous Materials Safety Administration
Kenneth Lee – Director
Engineering and Research Division
East Building, Room E22-334
1200 New Jersey Avenue, SE
Washington, DC 20590
Telephone: (202) 366-2694
Email: Kenneth.lee@dot.gov

G7. What specific items should be sent to PHMSA?

The applicant should submit a Design Spill Package directly to PHMSA to aid in the review process. Detailed engineering materials are required as part of the Design Spill Package.

The Design Spill Package should include:

a. Project description, background, purpose and details describing the proposed facility;
b. Hazard reports, including any attachments and referenced reports;
c. Facility location map(s), topography map(s), and site aerial photography;
d. Engineering drawings including an overall plot plan showing the project's property boundary and unit plot plans for each process area or system showing the location and elevation of major equipment. Each area and piece of equipment should be clearly labeled. The unit plot plans should be detailed enough to allow for measurement of distances between various components with a reasonable degree of accuracy. The smallest scale submitted should be no smaller than 1-inch to 100-feet (1:1200);
e. Piping and instrument drawings (P&ID);
f. Process Flow Diagrams (PFD);
g. Heat and Material Balance Sheets (H&MB);
h. Piping and Equipment Inventory Table of LNG plant components;
i. Pump and compressor curves for pumps and compressors used for hazardous fluid service (as available);
j. List of all intended direct discharge points to atmosphere (this should include vents and drains);
k. Sketch on plot plan showing expected locations and elevations of major potential single accidental leakage sources;
l. Dimensions, capacities, and thermal properties for any impoundments associated with this project;
m. Design details for vapor barriers;
n. The summary report of all input and output parameters for computer program simulations (i.e., PHAST) should be included.

   Note: The summary report will provide the design spill criteria and screening assessment that was used.

If additional information is required, PHMSA will work with the applicant on additional information submittals.

G8. After I submit information to PHMSA, how long will the review process take?

The duration of the review process varies. There are a variety of factors which influence the timeline for review and approval, including the volume of previously submitted applications, where the applicant is in the siting process, and the completeness of the submitted information. PHMSA will acknowledge receipt of the application and will begin the review process. PHMSA will contact the applicant during the review process to resolve any outstanding needs or questions.

G9. After I submit the required information to PHMSA, what information do I need to file on the FERC docket?

For those projects under FERC jurisdiction, all information submitted to PHMSA should be filed on the FERC docket. PHMSA will work with the applicant to review the information. If revisions or edits are necessary, the applicant will be instructed to file an addendum to the FERC docket.

G10. A FERC regulation (18 CFR § 385.2201) prohibits off-the-record communications in a contested, on-the-record proceeding. The rule is designed to limit communications between a "decisional employee" at FERC and persons outside the Commission. How do FERC's restrictions on ex parte communication affect PHMSA's communications with LNG project applicants?

The purpose of the rule is to ensure the integrity and fairness of the Commission's decisional process, and to prevent off-the-record communications relative to the merits of a Commission proceeding between FERC decisional employees and entities outside of the Commission. Generally, communications regarding Part 193 compliance between PHMSA and a party before the Commission do not violate FERC's ex parte rules. However, PHMSA takes care to not act as a conduit for otherwise unpermitted communications. Some communication between PHMSA and a facility applicant is expected, but PHMSA restricts those communications to matters that FERC has explicitly referred to PHMSA. In accordance with the FERC's public disclosure requirements and FERC's responsibilities under its ex parte regulations, PHMSA, as a cooperating agency, cannot release pre decisional information related to the NEPA analysis (such as working drafts of NEPA documents and PHMSA comments on those working drafts).

If PHMSA needs additional information from an applicant to resolve a matter that FERC has referred to us, PHMSA will advise FERC and the applicant of what additional information is needed and request that it be submitted to FERC's docket.

G11. How do operators notify PHMSA that construction, upgrade, or refurbishment of an LNG facility will be commencing?

New operators must first obtain an Operator Identification Number (OPID). To obtain on OPID, an operator must complete an OPID Assignment Request DOT Form PHMSA F 1000.1 through the National Registry of Pipeline and LNG Operators in accordance with § 191.22(a).

Each operator of an LNG plant or LNG facility is required to submit notification of specified events to PHMSA in accordance with § 191.22(c). Operators must use the Operator Registry Notification (Form PHMSA F 1000.2) to report new construction, asset-changing or program-changing events associated with LNG facilities. Within Form PHMSA F 1000.2, operators planning to begin new construction, refurbishment or an upgrade project, regardless of cost, select a Type J – New Construction Notification.

Construction notifications are required to be submitted 60 days prior to the "event." On September 12, 2014, PHMSA published an Advisory Bulletin describing the activities that constitute the "event" of construction, which determines the due date for the notification.

Note that operators have requirements for the reporting of incidents, safety-related conditions, and annual pipeline summary data in accordance with § 191.1 and to submit mapping data to the National Pipeline Mapping System (NPMS) in accordance with § 191.7. Requests for OPID, construction notifications, and reporting must be made online via the PHMSA portal, using assigned user name and password, unless an alternate method is approved. Copies of the forms and instructions for PHMSA F 7100.3 (Incident Report) and PHMSA F 7100.3-1 (Annual Report) can be found on the Pipeline Safety Community Web Page at http://phmsa.dot.gov/pipeline/library/forms. Contact the PHMSA Information Resources Manager at (202) 366-8075 if you have questions. For information about making an NPMS submission, see https://www.npms.phmsa.dot.gov/PipelineOperator.aspx.

G12. What are the siting requirements for small LNG facilities that have an aggregate storage capacity of 70,000 gallons or less on one site?

> **The writer asks, "Part 193 has requirements for thermal radiation exclusion and vapor-gas dispersion exclusion zones that are required for *each* LNG container and transfer system, but NFPA 59A, 2001 edition has Table 2.2.4.1 *Distances from Impoundment Areas to Buildings and Property Lines* for small LNG facilities with total onsite storage capacity of 70,000 gallons LNG or less. Does NFPA 59A, 2001 edition, Chapter 2, Plant Siting and Layout, Paragraph 2.2.3.7 which allows use of Table 2.2.4.1 'Distances from Impoundment Areas to Buildings and Property Lines' *conflict* with Part 193 Subpart B – Siting Requirements?"**

Part 193 siting requirements include the determination of exclusion zones, areas in which the operator or a government agency legally controls all activities. The exclusion zones are determined by complying with § 193.2057 *Thermal radiation protection* and § 193.2059 *Flammable vapor-gas dispersion protection*. These sections incorporate by reference NFPA 59A Paragraph 2.2.3.2 (thermal radiation distance) and paragraphs

2.2.3.3 and 2.2.3.4 (vapor dispersion distance). NFPA 59A Paragraph 2.2.3.7 is not provided as an alternative to § 193.2057 and § 193.2059 for permanent facilities.

Under § 193.2019, mobile and temporary LNG facilities need not meet the requirements of Part 193 (including Sections 193.2057 and 193.2059) if they comply with the applicable sections of NFPA 59A that is incorporated by reference. NFPA 59A Paragraph 2.3.4 covers the requirements for such facilities. 2.3.4(g) references Table 2.2.4.1 for the spacing guidelines at mobile and temporary facilities. When Table 2.2.4.1 is used for compliance with Paragraph 2.3.4 (g), the aggregate capacity of the multiple LNG containers on the temporary site is to be used to determine facility spacing.

(D) Design

D1. What wind speed should be used in LNG facility equipment design calculations?

Wind forces are addressed in 49 CFR § 193.2067, which requires that LNG facilities be designed to withstand the direct effect of wind forces without loss of structural or functional integrity. Structural engineering design is typically performed using 3-second gust wind speeds in miles-per-hour (mph).

For shop fabricated containers of LNG or other hazardous fluids with a capacity of not more than 70,000 gallons, the wind forces at the location of the specific facility must be based on applicable wind load data in ASCE/SEI 7-05.

For all other LNG facilities, the wind forces at the location of the specific facility must be based on one of the following:

a. an assumed sustained wind velocity of not less than 150 MPH; or
b. a sustained wind velocity of less than 150 MPH that is justified by adequate supportive data and found acceptable by the Administrator; or
c. the most critical combination of wind velocity and duration, with respect to the effect on the structure, having a probability of exceedance in a 50-year period of 0.5 percent or less, if adequate wind data are available and the probabilistic methodology is reliable.

For most structural engineering design calculations, the sustained wind velocity is converted to 3-second gust wind speed using a conservative method based on sound engineering principles. The Durst curve is an acceptable conversion method in ASCE/SEI 7-05, Chapter C6. Using this method, a sustained wind velocity of 150 mph is equivalent to a 183 mph 3-second gust. Applicants should also design all facilities to meet all applicable local or state building codes.

D2. To what parts of the facility does § 193.2067(b)(2) apply?

This paragraph applies to all LNG facilities other than those that are described in § 193.2067(b)(1). The term "LNG facility" is defined in 49 CFR § 193.2007. The parts of the LNG plant considered for compliance with this design requirement include all parts used when liquefying natural gas or transferring, storing, or vaporizing liquefied natural gas. This includes piping and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation.

D3. Should the wind speed design criteria of 193.2067 be applied to vapor barriers at the LNG plant?

Since vapor barriers are installed for the purpose of reducing the extent of exclusion zones, they are a part of the LNG facilities and subject to the regulatory wind speed requirements. Vapor barriers must be functional while the LNG facility is in operation.

D4. Can vacuum jacketed piping be used in an LNG plant and may the outer pipe be used for LNG impoundment?

The applicant must fully document any application of vacuum jacketed pipe (VJP) or vacuum insulated pipe (VIP). The design details of the piping as well as the locations where it is to be used must be provided. In cases where the VJP or VIP may affect the prescribed design spills, impoundment determinations, or other hazard calculations, the applicant must fully justify the position and approach being taken. PHMSA will review these applications on a case-by-case basis, and a special permit (see 49 CFR Section 190.341) may be required.

D5. As an operator of a LNG Facility, our pressure vessels will be designed and fabricated to the current American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (BPVC). This differs from the requirements of 49 C.F.R. Part 193. How can I ensure our pressure vessels comply with Part 193?

To comply with the requirements of 49 C.F.R. Part 193, each applicant for a LNG facility designed after March 10, 2004, must do one of the following:

- Ensure compliance with NFPA 59A-2001, Paragraph 3.4.2, using the 1992 ASME BPVC; or,
- Submit an application for a special permit in accordance with 49 C.F.R. § 190.341; or,
- Demonstrate an equivalent level of safety as described in NFPA 59A-2001, Section 1.2.

Any deviation from the above requirements for pressure vessels by an operator of a LNG facility will require submittal of technical documentation for review by PHMSA on a case-by-case basis.

D6. As a design engineering firm or as an operator of a LNG facility, if our pressure vessels are designed and fabricated to the current American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (BPVC), which methods may I use to demonstrate safety equivalency as described in NFPA 59A-2001, Section 1.2, and as mentioned in FAQ D5?

Refer to NFPA 59A (2001), Section 1.2 Equivalency, which states:

Nothing in this standard is intended to prevent the use of systems, methods, or devices of equivalent or superior quality, strength, fire resistance, effectiveness, durability, and safety over those prescribed by this standard. Technical documentation shall be submitted to the authority having jurisdiction to demonstrate equivalency. The system, method, or device shall be approved for the intended purpose by the authority having jurisdiction.

When pressure vessels are designed and fabricated for use under Part 193 by using a more recent edition of the ASME BPVC than the 1992 version, the Operator is responsible to document the method used to determine equivalency and make this technical documentation available to PHMSA upon request. PHMSA will accept one of the following methods to demonstrate equivalency in accordance with NFPA 59A-2001, Section 1.2:

- Pressure vessels may be designed and fabricated to meet the requirements for test pressure and design margin factors found in the 1992 edition of the ASME BPVC; *or,*
- The maximum allowable working pressure (MAWP) for the pressure vessels may be reduced by the amount that results in a test pressure for all pressure vessels meeting the requirements in the 1992 edition of the ASME BPVC Section VIII, Division 1 or Division 2; *or,*
- Longitudinal, circumferential, nozzle-to-shell, tube sheet, header box, and nozzle-to-box header welds may be inspected by nondestructive examination (NDE). All longitudinal and circumferential welds and nozzle-to-shell welds for process nozzles six (6) inches or larger in diameter must be subject to 100% NDE. Accepted NDE methods are radiograph testing (RT), ultrasonic testing (UT), magnetic particle testing (MPT or MT), and dye penetrant testing (DPT or PT) along the entire weld length in accordance with the applicable sections of the current ASME Section VIII or other applicable standards. Longitudinal and circumferential welds must be subject to radiographic or ultrasonic testing; *or,*
- The operator of the LNG facility may develop, document, and implement a systematic approach, with annual inspections not to exceed 15-months, to ensure the long-term integrity of all its pressure vessels and pressure-relieving devices protecting these vessels within the LNG facility. The asset-management procedure must incorporate and comply with a current recognized and generally accepted American National Standards Institute (ANSI) standard such as the American Petroleum Institute (API) 510, "Pressure Vessel Inspection Code: In-service Inspection, Rating, Repair, and Alteration," 10th Edition. The procedures must be adopted into the operator's operations and maintenance (O&M) manual. The procedures must be updated, as needed, for the continuous, effective management of pressure vessel integrity that must include over pressure protection, corrosion, pipe wall thickness loss, cracking on both girth and longitudinal welds and steel body, loading stresses such as loads on nozzles from piping, valves, other components, and soil settlement and environmental deterioration of the pressure vessel due to weathering. Adoption and implementation of a pressure vessel asset management plan is in addition to the existing minimum requirements for operations, maintenance, and personnel qualifications and training found in 49 CFR Part 193 and NFPA 59A-2001. The operator must maintain all records and procedures for design, construction, testing, repairs, and O&M activities as required in API 510. The "Risk Based Inspection" option in Section 6.3 of API 510 is not an acceptable O&M inspection and evaluation method;

or,

- The operator may submit to PHMSA another system, method, or device that is intended to demonstrate equivalency for evaluation and review on a case-by-case basis.

(DS) Design Spill Determination

DS1. The criteria and methodology used to identify single accidental leakage sources (SALS) to establish siting for my LNG facility were based on the failure rate table methodology. Do I need to submit a new or revised Design Spill Package to PHMSA based on the current SALS methodology?

No. PHMSA will not require the applicant to submit a new or revised Design Spill Package and will not retroactively apply the current SALS methodology to facilities that have received a previous PHMSA correspondence of no objection to their methodology for determining the SALS for design spills used in establishing the 49 CFR Part 193 siting requirements. If the applicant chooses to modify the design spills that were previously determined to be in compliance with Part 193 siting requirements, PHMSA will require an updated Design Spill Package as described in these FAQs. For those projects under FERC jurisdiction, the applicant will also need to file the updated information submitted to PHMSA on the FERC docket.

DS2. 49 CFR 193 requires that design spills for an LNG plant be selected according to NFPA 59A-2001 Paragraph 2.2.3.5. NFPA 59A requires the evaluation of accidental flow from "any single accidental leakage source" (SALS) but does not define this term. How should I select SALS events in an LNG plant?

For piping and equipment that handle LNG, flammable refrigerants, toxic components, or any other hazardous fluid, leakage sources may be chosen using the following guidelines. The SALS selection methodology, below, is applied to determine the maximum hole sizes of interest for the most significant releases of each hazardous fluid in each portion of the LNG plant. (The SALS selections are one component of design spill definition. Please refer to other FAQs for additional design spill definition topics.)

a. For piping segments that are:
    1. Greater than or equal to 6 inches in diameter, a hole of 2 inches in diameter is applied at any location along the piping segment, including at piping and transfer connections, marine transfer arms, double-ply construction expansion bellows, and gaskets;
    2. Less than 6 inches in diameter, a full-bore rupture (guillotine failure) is applied at any location along the piping segment;
    3. Isolated from the hazardous fluid stream with valves designated as car seal or locked closed and that are part of a plant maintenance program, leakage sources need not be considered.
b. For single-ply construction expansion bellows, a hole size equivalent to a full-bore rupture of the diameter of the expansion joint is applied;
c. For pipe-in-pipe systems, the hole or rupture is applied to the inner pipe. The impacts of this release onto the outer pipe must then be considered. The selection of an alternate hole size will be reviewed on a case-by-case basis. The pipe-in-pipe design must include an outer pipe that is capable of containing any released fluids should the inner pipe fail; and
d. For transfer hoses, a hole size equivalent to a full-bore rupture of the transfer hose is applied.

Alternative SALS selection methodologies, including those that apply the PHMSA failure rate table or a failure database used in a quantitative risk analysis may be provided to PHMSA on a case-by-case-basis for review.

DS3. PHMSA reviews the design criteria for design spills on a case-by- case basis to determine compliance with Part 193. What information is required to assist PHMSA in its determination of the design spill criteria acceptable for use?

Applicants must provide a piping inventory table of LNG plant components in hazardous or flammable fluid service. At a minimum, the table should include piping of 2 inches in diameter and larger as well as transfer hoses. The inventory table should be submitted in Excel (*.XL*) format. Separate tabs or lists should be used for each type of hazardous fluid, as well as a separate tab or list to present all of the final design spill selections. The table should include the following information:

a. Line segment scenario number to identify potential design spill;
b. Description of line segment;
c. General plant area or service (e.g. liquefaction train, refrigerant storage, marine area, etc.), unless the entire project is confined to one area;
d. Beginning point location (e.g., exchanger outlet flange) for each line;
e. Ending point location (e.g., pump suction nozzle) for each line;
f. Line diameter;
g. Operational mass flow rate in the line;
h. Hazardous fluid service (LNG, natural gas, refrigerants (such as ammonia, propane, ethane, mixed refrigerant), natural gas liquids (NGL) or gas condensate, hydrogen sulfide, benzene, etc.);
i. P&ID drawing number reference(s) for each segment;
j. Piping line designation on P&ID;
k. Fluid conditions within the line segment (e.g., fluid phase (liquid or vapor); density (lb/ft^3); pressure (psig); temperature (°F); flow rate, (lb/hr); composition of mixed refrigerants, NGL/condensates, acid gas);
l. Process flow diagram and corresponding heat and material balance stream number;
m. Leakage source hole size;
n. Calculated total mass flow rate;
o. For potential design spill selections, include release duration, height, rainout percentage, and total vapor mass flow rate, and
p. Comments including justification or other details for the final design spills selected.

DS4. Is the largest size hole always used as the hole size in release modeling?

Not necessarily. For any defined maximum hole size, the applicant must demonstrate that that the hole size selected produces the greatest vapor dispersion distance when accounting for the mechanisms of flashing, jetting, aerosol formation, and rain-out. If a smaller hole size creates a larger vapor dispersion hazard distance, that smaller hole size should be used to define the design spill event. This applies to all single accidental leakage sources, including failures at piping, piping connections, and transfer hoses.

DS5. What are the proper release height and orientation to use for a design spill?

For each design spill identified, the release height should be the one that defines the largest hazard distances, bounded within the actual or anticipated heights of the equipment and piping. Release orientation should be horizontal, unless an alternate release angle produces larger hazard distances.

For unidirectional piping less than 6 inches in diameter where a rupture is considered, an alternate orientation may be considered, based on the direction of the piping (e.g., vertically upward for connections to a relief valve inlet, vertically downward for a gravity drain connections). Where mitigation measures physically direct the released material (e.g., pipe shrouding that a fluid downward) specific directions may be considered.

DS6. How are release locations defined?

For single-ply expansion joint or transfer hose failures, the release location can be identified at the specific point of that component in the LNG plant. For piping segments, the selected hole can occur at any location along the piping segment. If vapor barriers, shrouds, or pipe-in-pipe designs are used to reduce the vapor dispersion distance, locations potentially not impacted by the vapor barrier, shroud, or pipe-in-pipe should also be selected.

DS7. How do I determine the process conditions to evaluate for hazard modeling?

Process conditions should be based on heat and material balance modes of operation and design case (e.g., rich, lean, average, etc.) that produce the worst case dispersion results from flashing and jetting and liquid releases. The leakage sources from branch connections should be considered using the potential operational conditions along the pipe as well as the potential operational conditions that could be experienced at or near the branch pipe connection to a main process line. In cases that would reduce the back pressure on pump(s) or compressor(s), the flow rates should consider the potential increased pump or compressor flow determined by the pump and compressor curve(s) as detailed in DS10 and also consider the decrease in temperature and pressure during runout conditions.

DS8. Is it permissible to use spill duration of less than 10 minutes for design spill calculations?

For design spills other than those from LNG containers, the event is defined in NFPA 59A to last "for 10 minutes or a shorter time based on demonstrable surveillance and shutdown provisions acceptable to the authority having jurisdiction." Demonstrable surveillance and shutdown should include the time required to detect that the spill is occurring, the time to alert operators to this condition, the time required for operators to take action, and the time for the system to fully respond to the shutdown action that is initiated, including any valve closure times. In this case, the applicant should provide a detailed justification to demonstrate that the shorter time is justified.

In cases where a system may deplete its inventory in less than 10 minutes, a release duration of less than 10 minutes may be used. In this case, the applicant should provide a detailed justification to demonstrate that the shorter time is justified and accounts for the entire available system inventory.

DS9. What considerations should be given to system inventory in the design spill definition?

The release modeling should account for the available system inventory (including pipework, process vessels, and other process equipment), the normal flow of fluid into the system, and the demonstrable surveillance and shutdown provisions as applicable to the scenario being modeled. The release modeling should also continue (even beyond 10 minutes) until the available system inventory is depleted; available system inventory may be modified during the event by valve closures. For systems that rely on isolation by emergency shutdown valves, the valves must be protected from failure, including fire and external impacts.

In the event the duration would potentially be greater than 10 minutes, release and dispersion modeling should continue after 10 minutes unless a release is demonstrated to reach its furthest vapor dispersion extent within 10 minutes.

DS10. Do I need to consider pump run-out in release scenario calculations?

Applicants should use pump run-out (greater flow than in normal pump flow operations) in failure calculations if the pump design allows increases in flow as the discharge pressure is reduced, unless acceptable preventive measures are used that prevent the pump from run out conditions. Pump runout parameters are presented by the pump manufacturer as a pump curve that shows flow increasing as the discharge pressure decreases. If pump run-out flows are not known at the time of submittal, engineering estimates may be employed provisionally.

Acceptable preventive measures include pump interlocks or safety instrumented prevention systems that meet safety integrity level (SIL) 2 or SIL3 reliability design and maintenance requirements in accordance with the International Society of Automation (ISA) 84 standards.

DS11. Should multiple pumps be considered when calculating the greatest flow from a spill to size impoundments or when defining a single accidental leakage source event?

Where the greatest flow is potentially fed from multiple pumps, calculate the flow to size impoundments assuming that all pumps are running, unless acceptable preventive measures are used that prevent all pumps from running concurrently.

Where a piping system utilizes multiple pumps, calculate the design spill based on the total flow from all system pumps running, unless acceptable preventive measures are used that prevent or limit all pumps from running concurrently.

Acceptable preventive measures include pump interlocks or safety instrumented prevention systems that meet safety integrity level (SIL) 2 or SIL 3 reliability design and maintenance requirements in accordance with the International Society of Automation (ISA) 84 standards.

(H) Hazards and Hazards Modeling

H1. Other than the flammable vapor dispersion and thermal radiation from hazards associated with LNG, what other hazards should be evaluated in the siting analysis for an LNG plant?

According to NFPA 59A-2001 Paragraph 2.1.1(d), (incorporated by reference in 49 CFR Part 193), all hazards that can affect the safety of the public or plant personnel are to be considered. In addition to LNG, the applicant should consider hazards associated with flammable gases, flammable refrigerants, flammable or combustible liquids, or acutely toxic materials. If present at the LNG plant, hazards including vapor dispersion from liquid pools, vapor dispersion from jetting and flashing phenomena, thermal radiation from pool fires, thermal radiation from fires involving jetting and flashing phenomena (jet fires), overpressure from vapor cloud ignitions, toxic gas dispersion, and boiling liquid expanding vapor explosions (BLEVEs) involving pressurized storage vessels should be included in an LNG plant's hazard evaluation.

H2. My LNG plant includes some toxic materials. What considerations should be given to accidental releases of these materials and the associated hazard modeling?

While the hazards associated with toxic substances at an LNG plant are not prescriptively covered in 49 CFR Part 193, their consideration is required by NFPA 59A-2001 Paragraph 2.1.1(d) (incorporated by reference in 49 CFR Part 193), which requires that all hazards that can affect the safety of the public or plant personnel be considered. Consideration of toxic hazards must include dispersion modeling appropriate for the toxic substance on site as well as incorporating safety measures of the design and operation of the facility.

Many toxic substances are regulated under the EPA's "Risk Management Program for Chemical Accidental Release Prevention" (RMP, 40 CFR 68) and OSHA's "Process Safety Management of Highly Hazardous Chemicals" (PSM, 29 CFR 1910.119). Compliance with EPA's RMP and OSHA's PSM regulations is a sufficient approach to comply with NFPA 59A Paragraph 2.1.1(d). PHMSA does not have authority to enforce EPA or OSHA regulations, but requires operator compliance with NFPA 59A Paragraph 2.1.1(d).

Applicants may propose alternative modeling methods to comply with NFPA 59A Paragraph 2.1.1(d) for toxic substances. The release scenario selection methodology should be consistent with the selection methodology for the single accidental leakage sources from LNG systems. When modeling the vapor dispersion of toxics, models should properly account for behavior of released materials. The ERPG-2 value (as specified by the RMP regulations) is the preferred endpoint to be used in the calculations. Because there are no specific exclusion zones that are to be defined for toxic materials, the offsite impacts at each proposed LNG plant will be evaluated on a case-by-case basis.

H3. Materials received, stored, or used at my LNG plant could generate overpressures from a vapor cloud explosion. What considerations should be given to vapor cloud explosions and the associated hazard modeling?

While explosion overpressure is not prescriptively covered in 49 CFR Part 193, its consideration is required by NFPA 59A-2001 Paragraph 2.1.1(d) (incorporated by reference in 49 CFR Part 193), which requires that all hazards that can affect the safety of the public or plant personnel be considered. Vapor cloud explosion modeling should involve consideration of vapor dispersion modeling results, evaluation of areas of confinement and congestion, and the potential reactivity of released materials. The use of the 1.0 psi overpressure endpoint is appropriate for explosion modeling, and is consistent with the EPA's "Risk Management Program for Chemical Accidental Release Prevention" (RMP, 40 CFR 68). Because there are no specific exclusion zones that are to be defined for explosion overpressure impacts, the offsite impacts at each proposed LNG plant will be evaluated on a case-by-case basis.

H4. What wind direction should be used in exclusion zone and other hazard calculations?

For most hazard calculations, the exclusion distance or hazard distance is calculated independent of wind direction. If the wind direction is important in the modeling methods used, the direction used should be toward the nearest property line. Additional wind directions may also need to be analyzed if the hazard could extend beyond other property lines or cause other unique hazards.

H5. Can an exclusion zone extend beyond the operator's LNG plant property line?

As long as the facility is in operation, the operator is responsible for assuring compliance with the limitations on land use within exclusion zones, according to the descriptions in NFPA 59A

Sections 2.2.3.2, 2.2.3.3, and 2.2.3.4. For example, an exclusion zone that extends past a property line into a navigable body of water or onto a public road is typically acceptable. This may not hold true if that body of water contains a dock or pier that is not controlled by the operator of the LNG plant, or if another entity could erect a building or members of the public could assemble within the exclusion zone. It is possible to assure compliance by legal agreement with a property owner affected by the exclusion zone, such that the land use is restricted for the life of the LNG plant.

H6. In addition to DEGADIS 2.1 and FEM3A, Section 193.2059 Flammable vapor dispersion protection provides for the use of alternate models approved by US DOT PHMSA. What other models have been approved?

US DOT PHMSA has approved two additional models for the determination of vapor dispersion exclusion zones: FLACS 9.1 Release 2 (October 7, 2011) and PHAST-UDM Version 6.6 and 6. 7 (October 7, 2011). Each model has been validated for use in certain conditions in accordance with the Model Evaluation Protocol (MEP) as described in M. J. Ivings et al., Evaluating Vapor Dispersion Models for Safety Analysis of LNG Facilities Research Project: Technical Report (April 2007) (available at http://www.nfpa.org).

For detailed information regarding the conditions for which the models were validated, see PHMSA's final decision at:

FLACS http://www.regulations.gov/#!docketDetail;D=PHMSA-2011-0101

PHAST http://www.regulations.gov/#!docketDetail;D=PHMSA-2011-0075

H7. Does US DOT PHMSA prescribe source term models for flammable vapor dispersion modeling?

While PHMSA does not prescribe or approve source term models, the source term model must have a creditable scientific basis and must not ignore any phenomena that can influence vapor formation during discharge from containment, conveyance to an impoundment, and retention within the impoundment. In July, 2010 PHMSA communicated in interpretation PI-10-0021 that the SOURCE5 model does not satisfy the PHMSA requirements for a source term model. The interpretation can be viewed at:

http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=319134025ed5b210VgnVCM1000001ecb7898RCRD.

H8. Can mitigation measures be used in exclusion zone and other hazard calculations?

For most hazard calculations, passive mitigation measures are inherently acceptable, provided that their design and implementation can be technically supported and that they do not introduce other harmful consequences.

Active or procedural mitigation measures are generally not included exclusion zone or hazard zone calculations. However, PHMSA will review the proposed inclusion of such measures on a case-by-case basis, provided that proper supporting technical justification and documentation is submitted.

Revised: 1/10/2017

Frequently Asked Questions

https://www.phmsa.dot.gov/faqs/liquefied-natural-gas

July 25, 2017

(G) General

G1. The abundant supply of domestic natural gas is driving development of new ways to use, process, and transport LNG. Can PHMSA provide guidance as to which LNG facilities are regulated under 49 CFR Part 193?

The Pipeline Safety Statute codified in 49 U.S. Code § 60101, et seq, directs US DOT to establish and enforce standards for liquefied natural gas pipeline facilities. An LNG facility is a gas pipeline facility used for converting, transporting or storing liquefied natural gas.

Many LNG facilities are subject to the regulatory and enforcement authority of the Department of Transportation through PHMSA. A simple but not complete test to determine if an LNG facility is regulated under 49 CFR Part 193 is to identify both the source and the consumer of the LNG. The facility is regulated under 49 CFR Part 193 if the LNG facility either receives from or delivers to a 49 CFR Part 192 pipeline.

49 CFR Part 193 does not apply to:

1. LNG facilities used by ultimate consumers of LNG or natural gas.
2. LNG facilities used in the course of natural gas treatment or hydrocarbon extraction that do not store LNG.
3. In marine cargo transfer systems and associated facilities, any matter other than siting pertaining to the system or facilities between the marine vessel and the last manifold (or, in the absence of a manifold, the last valve) located immediately before a storage tank.
4. Any LNG facility located in navigable waters (as defined in Section 3(8) of the Federal Power Act (16 U.S.C. 796(8)).

Operators should assume an LNG facility used in the transportation of gas by a 49 CFR Part 192 pipeline is regulated under 49 CFR Part 193 unless specifically exempted in Section 193.2001(b). LNG facilities may be regulated by PHMSA even though they are not regulated by the FERC. The 'ultimate consumer' provision provides a very limited exemption from 49 CFR Part 193. PHMSA interpretation # PI-10-0025 provides guidance. Here is an excerpt:

> *During the rulemaking that led to the adoption of § 193.2001(b)(1), OPS explained that the intent of that provision was to create an exception for "an LNG facility used by the ultimate consumer of the product". Likewise, in responding to a series of questions from a congressional committee, OPS stated that the exception in § 193.2001(b)(1), was designed for "small" facilities which are "generally located in industrial plants ... [to] serve as a supply of energy or feedstock for the plant." Unlike these examples, the Maine LMF facilities would be used to produce LNG for sale and distribution by truck, not solely for onsite consumption. Therefore, OPS concludes that your client's facilities would not qualify for the end-user exception in § 193.2001(b)(1).*

G2. What agency or agencies have regulatory authority over the siting of LNG facilities?

There are more than 110 liquefied natural gas (LNG) facilities operating in the U.S. performing a variety of services. Most of these facilities store LNG for "peak shaving," where the LNG is vaporized and transported in gas transmission or gas distribution pipelines for periods of peak demand. There is significant growth in the number of facilities producing LNG as a transportation vehicle fuel for trucks, buses, trains, and ships. Depending on the location and use, several Federal agencies and State utility regulatory agencies may regulate an LNG facility.

For LNG import and export facilities located onshore, three Federal agencies share oversight for safety and security: the Federal Energy Regulatory Commission (FERC), the U.S. Coast Guard, and the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA). Under Section 3 of the Natural Gas Act of 1938, FERC is responsible for authorizing the siting and construction of onshore and near-shore LNG import or export facilities. Under Section 7 of the Natural Gas Act of 1938, FERC also issues certificates of public convenience and necessity for LNG facilities engaged in interstate natural gas transportation by pipeline. As required by the National Environmental Policy Act (NEPA), FERC prepares NEPA analyses for proposed LNG facilities under its jurisdiction. The Coast Guard has authority over the safety of LNG vessels and the marine transfer area, conducting Waterway Suitability Assessments to address navigation safety and port security issues associated with LNG ship traffic. PHMSA has authority to establish and enforce safety standards for onshore LNG facilities.

PHMSA's regulations for LNG facilities appear in Title 49, Part 193 of the Code of Federal Regulations (CFR). LNG facility applicants, when applying to FERC, are required to identify how their proposed facility would meet the siting requirements of 49 CFR Part 193. FERC consults with its cooperating agencies, including PHMSA, as needed. Once FERC approves a project and the applicant moves forward in the process, PHMSA inspects sites during and after construction, and during facility operation, and is responsible for taking enforcement action under Part 193 if necessary.

G3. As an operator, how do I submit an application to install a FERC regulated LNG facility?

The FERC is responsible for authorizing the siting and construction of onshore and near-shore LNG import or export facilities and LNG facilities engaged in interstate natural gas transportation by pipeline. As an operator of one of these types of facilities, you must coordinate with the FERC in the development of the Resource Reports required for the FERC application process. Information on Resource Reports 11 & 13, which deals with the engineering detail of the LNG facility, can be found in 18 CFR 380.12(m)&(o).

G4. What types of LNG facilities require information submittal?

If an LNG facility requires FERC review and siting approval, PHMSA as a cooperating agency will require detailed information as described in these FAQs. Please refer to Subpart A of Part 193 for scope and applicability of PHMSA's regulations. There are regulations in Part 193 pertaining to siting, design, construction, equipment, maintenance, personnel qualifications and training, fire protection, and security. If the operator has questions or needs further guidance on the applicability of Part 193 to the facility in question, then the operator may contact PHMSA headquarters or the PHMSA Regional Offices. PHMSA's regional contact information is located here, or you may contact PHMSA's Director of Engineering as noted below under FAQ #G6.

G5. Does PHMSA have an application or permitting process for new or modified LNG facilities that are subject to the jurisdiction of Part 193 but does not require FERC review?

PHMSA does not require an application process and does not have authority for permitting LNG facilities. PHMSA requires LNG operators submit information to the National Registry of Pipeline and LNG Operators database 60 days prior to commencing construction. See FAQ #G10 below for more information.

LNG operators may be required to submit an application to the Federal Energy Regulatory Agency (FERC) or the appropriate state agency. Operators must notify the State Pipeline Safety Agencies at least 2 weeks prior to the installation of portable LNG facilities and provide information prescribed in § 193.2019 (b).

Determining how to comply with 49 CFR 193 is the responsibility of the operator. PHMSA is available to answer your questions. Please contact Ken Lee, Director, Engineering and Research Division (202) 366-2694 or by email kenneth.lee@dot.gov.

G6. Since PHMSA is a cooperating agency in the FERC siting process, do I need to provide anything directly to PHMSA in order to help expedite the application process?

Yes. If a facility is subject to Part 193 (see reply to FAQ #G3 above), then in order for PHMSA to perform an in-depth review and analysis, you should copy and forward specific items for evaluation. You should send all application materials directly to FERC, but you should also submit to PHMSA hard and digital copies of the documents noted in these FAQs to aid PHMSA in its review. Review of your application will be delayed unless you promptly submit to PHMSA substantially complete application materials. Please also be aware that PHMSA will need detailed materials without any redaction, regardless of security sensitive or proprietary information, in order to conduct a full review. If you believe your materials are security sensitive or proprietary in any way, please mark them accordingly.

Materials noted below should be addressed to:

U.S. Department of Transportation
Pipeline & Hazardous Materials Safety Administration
Kenneth Lee – Director
Engineering and Research Division
East Building, Room E22-334
1200 New Jersey Avenue, SE
Washington, DC 20590
Telephone: (202) 366-2694
Email: kenneth.lee@dot.gov

G7. What specific items should be sent to PHMSA?

The applicant should submit a Design Spill Package directly to PHMSA to aid in the review process. Detailed engineering materials are required as part of the Design Spill Package.

The Design Spill Package should include:

a. Project description, background, purpose and details describing the proposed facility;
b. Hazard reports, including any attachments and referenced reports;

c. Facility location map(s), topography map(s), and site aerial photography;
d. Engineering drawings including an overall plot plan showing the project's property boundary and unit plot plans for each process area or system showing the location and elevation of major equipment. Each area and piece of equipment should be clearly labeled. The unit plot plans should be detailed enough to allow for measurement of distances between various components with a reasonable degree of accuracy. The smallest scale submitted should be no smaller than 1-inch to 100-feet (1:1200);
e. Piping and instrument drawings (P&ID);
f. Process Flow Diagrams (PFD);
g. Heat and Material Balance Sheets (H&MB);
h. Piping Inventory Table;
i. Pump and compressor curves for pumps and compressors used for hazardous fluid service (as available);
j. Sketch on plot plan showing expected locations and elevations of major potential single accidental leakage sources;
k. Dimensions, capacities, and thermal properties for any impoundments associated with this project;
l. Design details for mitigation measures, including vapor barriers and pipe-in-pipe systems; and
m. The summary report of all input and output parameters for computer program simulations (i.e., PHAST) should be included.

   Note: The summary report will provide the design spill criteria and screening assessment that was used.

If additional information is required, PHMSA will work with the applicant on additional information submittals.

G8. After I submit information to PHMSA, how long will the review process take?

The duration of the review process varies. There are a variety of factors which influence the timeline for review and approval, including the volume of previously submitted applications, where the applicant is in the siting process, and the completeness of the submitted information. PHMSA will acknowledge receipt of the application and will begin the review process. PHMSA will contact the applicant during the review process to resolve any outstanding needs or questions.

G9. After I submit the required information to PHMSA, what information do I need to file on the FERC docket?

For those projects under FERC jurisdiction, all information submitted to PHMSA should be filed on the FERC docket. PHMSA will work with the applicant to review the information. If revisions or edits are necessary, the applicant will be instructed to file an addendum to the FERC docket.

G10. A FERC regulation (18 CFR § 385.2201) prohibits off-the-record communications in a contested, on-the-record proceeding. The rule is designed to limit communications between a "decisional employee" at FERC and persons outside the Commission. How do FERC's restrictions on ex parte communication affect PHMSA's communications with LNG project applicants?

The purpose of the rule is to ensure the integrity and fairness of the Commission's decisional process, and to prevent off-the-record communications relative to the merits of a Commission proceeding between FERC decisional employees and entities outside of the Commission. Generally, communications regarding Part 193 compliance between PHMSA and a party before the Commission do not violate FERC's ex parte rules. However, PHMSA takes care to not act as a conduit for otherwise unpermitted communications. Some communication between PHMSA and a facility applicant is expected, but PHMSA restricts those communications to matters that FERC has explicitly referred to PHMSA. In accordance with the FERC's public disclosure requirements and FERC's responsibilities under its ex parte regulations, PHMSA, as a cooperating agency, cannot release pre decisional information related to the NEPA analysis (such as working drafts of NEPA documents and PHMSA comments on those working drafts).

If PHMSA needs additional information from an applicant to resolve a matter that FERC has referred to us, PHMSA will advise FERC and the applicant of what additional information is needed and request that it be submitted to FERC's docket.

G11. How do operators notify PHMSA that construction, upgrade, or refurbishment of an LNG facility will be commencing?

New operators must first obtain an Operator Identification Number (OPID). To obtain on OPID, an operator must complete an OPID Assignment Request DOT Form PHMSA F 1000.1 through the National Registry of Pipeline and LNG Operators in accordance with § 191.22(a).

Each operator of an LNG plant or LNG facility is required to submit notification of specified events to PHMSA in accordance with § 191.22(c). Operators must use the Operator Registry Notification (Form PHMSA F 1000.2) to report new construction, asset-changing or program-changing events associated with LNG facilities. Within Form PHMSA F 1000.2, operators planning to begin new construction, refurbishment or an upgrade project, regardless of cost, select a Type J – New Construction Notification.

Construction notifications are required to be submitted 60 days prior to the "event." On September 12, 2014, PHMSA published an Advisory Bulletin describing the activities that constitute the "event" of construction, which determines the due date for the notification. The types of construction events that would initiate a notification submittal include material purchasing and manufacturing, right-of-way acquisition, construction equipment move-in activities, onsite or offsite fabrications, or right-of-way clearing, grading and ditching.

Note that operators have requirements for the reporting of incidents, safety-related conditions, and annual pipeline summary data in accordance with § 191.1 and to submit mapping data to the National Pipeline Mapping System (NPMS) in accordance with § 191.7. Requests for OPID, construction notifications, and reporting must be made online via the PHMSA portal, using assigned user name and password, unless an alternate method is approved. Copies of the forms and instructions for PHMSA F 7100.3 (Incident Report) and PHMSA F 7100.3-1 (Annual Report) can be found on the Pipeline Safety Community Web Page at https://phmsa.dot.gov/pipeline/library/forms. Contact the PHMSA Information Resources Manager at (202) 366-8075 if you have questions. For information about making an NPMS submission, see https://www.npms.phmsa.dot.gov/PipelineOperator.aspx.

G12. What are the siting requirements for small LNG facilities that have an aggregate storage capacity of 70,000 gallons or less on one site?

The writer asks, "Part 193 has requirements for thermal radiation exclusion and vapor-gas dispersion exclusion zones that are required for *each* LNG container and transfer system, but NFPA 59A, 2001 edition has Table 2.2.4.1 *Distances from Impoundment Areas to Buildings and Property Lines* for small LNG facilities with total onsite storage capacity

of 70,000 gallons LNG or less. Does NFPA 59A, 2001 edition, Chapter 2, Plant Siting and Layout, Paragraph 2.2.3.7 which allows use of Table 2.2.4.1 'Distances from Impoundment Areas to Buildings and Property Lines' *conflict* with Part 193 Subpart B – Siting Requirements?"

Part 193 siting requirements include the determination of exclusion zones, areas in which the operator or a government agency legally controls all activities. The exclusion zones are determined by complying with § 193.2057 *Thermal radiation protection* and § 193.2059 *Flammable vapor-gas dispersion protection*. These sections incorporate by reference NFPA 59A Paragraph 2.2.3.2 (thermal radiation distance) and Paragraphs 2.2.3.3 and 2.2.3.4 (vapor dispersion distance). NFPA 59A Paragraph 2.2.3.7 is not provided as an alternative to § 193.2057 and § 193.2059 for permanent facilities.

Under § 193.2019, mobile and temporary LNG facilities need not meet the requirements of Part 193 (including Sections 193.2057 and 193.2059) if they comply with the applicable sections of NFPA 59A that is incorporated by reference. NFPA 59A Paragraph 2.3.4 covers the requirements for such facilities. 2.3.4(g) references Table 2.2.4.1 for the spacing guidelines at mobile and temporary facilities. When Table 2.2.4.1 is used for compliance with Paragraph 2.3.4 (g), the aggregate capacity of the multiple LNG containers on the temporary site is to be used to determine facility spacing.

(D) Design

D1. What wind speed should be used in LNG facility equipment design calculations?

Wind forces are addressed in 49 CFR § 193.2067, which requires that LNG facilities be designed to withstand the direct effect of wind forces without loss of structural or functional integrity. Structural engineering design is typically performed using 3-second gust wind speeds in miles-per-hour (mph).

For shop fabricated containers of LNG or other hazardous fluids with a capacity of not more than 70,000 gallons, the wind forces at the location of the specific facility must be based on applicable wind load data in ASCE/SEI 7-05.

For all other LNG facilities, the wind forces at the location of the specific facility must be based on one of the following:

a. an assumed sustained wind velocity of not less than 150 MPH; or
b. a sustained wind velocity of less than 150 MPH that is justified by adequate supportive data and found acceptable by the Administrator; or
c. the most critical combination of wind velocity and duration, with respect to the effect on the structure, having a probability of exceedance in a 50-year period of 0.5 percent or less, if adequate wind data are available and the probabilistic methodology is reliable.

For most structural engineering design calculations, the sustained wind velocity is converted to 3 second gust wind speed using a conservative method based on sound engineering principles. The Durst curve is an acceptable conversion method in ASCE/SEI 7-05, Chapter C6. Using this method, a sustained wind velocity of 150 mph is equivalent to a 183 mph 3-second gust. Applicants should also design all facilities to meet all applicable local or state building codes.

D2. To what parts of the facility does § 193.2067(b)(2) apply?

This paragraph applies to all LNG facilities other than those that are described in § 193.2067(b)(1). The term "LNG facility" is defined in 49 CFR § 193.2007. The parts of the LNG plant considered for compliance with this design requirement include all parts used when liquefying natural gas or transferring, storing, or vaporizing liquefied natural gas. This includes piping and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation.

D3. Should the wind speed design criteria of 193.2067 be applied to vapor barriers at the LNG plant?

Since vapor barriers are installed for the purpose of reducing the extent of exclusion zones, they are a part of the LNG facilities and subject to the regulatory wind speed requirements. Vapor barriers must be functional while the LNG facility is in operation.

D4. Can vacuum jacketed piping be used in an LNG plant and may the outer pipe be used for LNG impoundment?

The applicant must fully document any application of vacuum jacketed pipe (VJP) or vacuum insulated pipe (VIP). The design details of the piping as well as the locations where it is to be used must be provided. In cases where the VJP or VIP may affect the prescribed design spills, impoundment determinations, or other hazard calculations, the applicant must fully justify the position and approach being taken. PHMSA will review these applications on a case-by-case basis, and a special permit (see 49 CFR Section 190.341) may be required.

D5. As an operator of a LNG Facility, our pressure vessels will be designed and fabricated to the current American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (BPVC). This differs from the requirements of 49 C.F.R. Part 193. How can I ensure our pressure vessels comply with Part 193?

To comply with the requirements of 49 C.F.R. Part 193, each applicant for a LNG facility designed after March 10, 2004, must do one of the following:

- Ensure compliance with NFPA 59A-2001, Paragraph 3.4.2, using the 1992 ASME BPVC; or,
- Submit an application for a special permit in accordance with 49 C.F.R. § 190.341; or, Demonstrate an equivalent level of safety as described in NFPA 59A-2001, Section 1.2.

Any deviation from the above requirements for pressure vessels by an operator of a LNG facility will require submittal of technical documentation for review by PHMSA on a case-by-case basis.

D6. As a design engineering firm or as an operator of a LNG facility, if our pressure vessels are designed and fabricated to the current American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (BPVC), which methods may I use to demonstrate safety equivalency as described in NFPA 59A-2001, Section 1.2, and as mentioned in FAQ D5?

Refer to NFPA 59A (2001), Section 1.2 Equivalency, which states:

Nothing in this standard is intended to prevent the use of systems, methods, or devices of equivalent or superior quality, strength, fire resistance, effectiveness, durability, and safety over those prescribed by this standard. Technical documentation shall be submitted to the authority having jurisdiction to demonstrate equivalency. The system, method, or device shall be approved for the intended purpose by the authority having jurisdiction.

When pressure vessels are designed and fabricated for use under Part 193 by using a more recent edition of the ASME BPVC than the 1992 version, the Operator is responsible to document the method used to determine equivalency and make this technical documentation available to PHMSA upon request. PHMSA will accept one of the following methods to demonstrate equivalency in accordance with NFPA 59A-2001, Section 1.2:

- Pressure vessels may be designed and fabricated to meet the requirements for test pressure and design margin factors found in the 1992 edition of the ASME BPVC; *or,*
- The maximum allowable working pressure (MAWP) for the pressure vessels may be reduced by the amount that results in a test pressure for all pressure vessels meeting the requirements in the 1992 edition of the ASME BPVC Section VIII, Division 1 or Division 2; *or,*
- Longitudinal, circumferential, nozzle-to-shell, tube sheet, header box, and nozzle-to-box header welds may be inspected by nondestructive examination (NDE). All longitudinal and circumferential welds and nozzle-to-shell welds for process nozzles six (6) inches or larger in diameter must be subject to 100% NDE. Accepted NDE methods are radiograph testing (RT), ultrasonic testing (UT), magnetic particle testing (MPT or MT), and dye penetrant testing (DPT or PT) along the entire weld length in accordance with the applicable sections of the current ASME Section VIII or other applicable standards. Longitudinal and circumferential welds must be subject to radiographic or ultrasonic testing; *or,*
- The operator of the LNG facility may develop, document, and implement a systematic approach, with annual inspections not to exceed 15-months, to ensure the long-term integrity of all its pressure vessels and pressure-relieving devices protecting these vessels within the LNG facility. The asset-management procedure must incorporate and comply with a current recognized and generally accepted American National Standards Institute (ANSI) standard such as the American Petroleum Institute (API) 510, "Pressure Vessel Inspection Code: In-service Inspection, Rating, Repair, and Alteration," 10th Edition. The procedures must be adopted into the operator's operations and maintenance (O&M) manual. The procedures must be updated, as needed, for the continuous, effective management of pressure vessel integrity that must include over pressure protection, corrosion, pipe wall thickness loss, cracking on both girth and longitudinal welds and steel body, loading stresses such as loads on nozzles from piping, valves, other components, and soil settlement and environmental deterioration of the pressure vessel due to weathering. Adoption and implementation of a pressure vessel asset management plan is in addition to the existing minimum requirements for operations, maintenance, and personnel qualifications and training found in 49 CFR Part 193 and NFPA 59A-2001. The operator must maintain all records and procedures for design, construction, testing, repairs, and O&M activities as required in API 510. The "Risk Based Inspection" option in Section 6.3 of API 510 is not an acceptable O&M inspection and evaluation method; *or,*
- The operator may submit to PHMSA another system, method, or device that is intended to demonstrate equivalency for evaluation and review on a case-by-case basis.

(DS) Design Spill Determination

DS1. The criteria and methodology used to identify single accidental leakage sources (SALS) to establish siting for my LNG facility were based on the failure rate table methodology. Do I need to submit a new or revised Design Spill Package to PHMSA based on the current SALS methodology?

No. PHMSA will not require the applicant to submit a new or revised Design Spill Package and will not retroactively apply the current SALS methodology to facilities that have received a previous PHMSA correspondence of no objection to their methodology for determining the SALS for design spills used in establishing the 49 CFR Part 193 siting requirements. If the applicant chooses to modify the design spills that were previously determined to be in compliance with Part 193 siting requirements, PHMSA will require an updated Design Spill Package as described in these FAQs. For those projects under FERC jurisdiction, the applicant will also need to file the updated information submitted to PHMSA on the FERC docket.

DS2. 49 CFR 193 requires that design spills for an LNG plant be selected according to NFPA 59A-2001 Paragraph 2.2.3.5. NFPA 59A requires the evaluation of accidental flow from "any single accidental leakage source" (SALS) but does not define this term. How should I select SALS events in an LNG plant?

For piping and equipment that handle LNG, flammable refrigerants, toxic components, and any other hazardous fluid, leakage sources may be chosen using the following guidelines. The SALS selection methodology, below, is applied to determine the maximum hole sizes of interest for the most significant releases of each hazardous fluid in each portion of the LNG plant. (The SALS selections are one component of design spill definition. Please refer to other FAQs for additional design spill definition topics.)

a. For piping segments, including transfer arms and double-ply construction expansion bellows, that are:
   1. Greater than or equal to 6 inches in diameter, a hole of 2 inches in diameter is applied at any location along the piping segment; and
   2. Less than 6 inches in diameter, a full-bore rupture (guillotine failure) is applied at any location along the piping segment.
b. For single-ply construction expansion bellows, a hole size equivalent to a full-bore rupture of the diameter of the expansion joint is applied;
c. For pipe-in-pipe systems, an unobstructed release from an equivalent 1-inch diameter hole may be applied at the operating conditions of the inner pipe when:
   1. The system complies with NFPA 59A (2016) Section 9.11;
   2. The outer pipe is able to withstand the thermal shock, mechanical forces, and pressure loads of any single accidental leakage source from A and B above applied to the inner pipe; and
   3. Design, fabrication, examination, and testing of the pipe-in-pipe system, including calculations, can be demonstrated.

   The selection of any alternate hole size or release scenario definition will be reviewed on a case-by-case basis in lieu of the criteria defined above; and
d. For transfer hoses, a hole size equivalent to a full-bore rupture of the transfer hose is applied.

DS3. PHMSA reviews the design criteria for design spills on a case-by- case basis to determine compliance with Part 193. What information is required to assist PHMSA in its determination of the design spill criteria acceptable for use?

Applicants must provide a piping inventory table of LNG plant components in hazardous or flammable fluid service. At a minimum, the table should include piping of 2 inches in diameter and larger, as well as transfer hoses. The inventory table should be submitted in Excel (*.XL*) format. Separate tabs or lists should be used for each type of hazardous fluid, with demarcation of all of the final design spill selections. The table should include the following information:

a. Line segment scenario number to identify the leakage source scenario;
b. Description of line segment purpose (LNG rundown header, KO Drum drain, relief valve inlet, level gauge instrument connection, etc.);
c. General plant area or service (e.g. liquefaction train, refrigerant storage, marine area, etc.), unless the entire project is confined to one area;
d. Beginning point location (e.g., exchanger outlet flange) for each line;
e. Ending point location (e.g., pump suction nozzle) for each line;
f. Line diameter;
g. Hazardous fluid service (LNG, natural gas, refrigerants (such as propane, ethane, mixed refrigerant), ammonia, natural gas liquids (NGL) or gas condensate, acid gas (containing hydrogen sulfide), etc.);
h. P&ID drawing number reference(s) for each segment;
i. Piping line designation on P&ID
j. Fluid conditions within the line segment (e.g., fluid phase (liquid or vapor); density (lb/ft^3); pressure (psig); temperature (°F); mass flow rate, (lb/hr); composition of mixed refrigerants, NGL/condensates, acid gas (mol%));
k. Process flow diagram and corresponding heat and material balance stream number;
l. Heat and material balance case selection;
m. Leakage source hole size;
n. Calculated total release flow rate (lb/hr);
o. Calculated depressurization or equilibrium pressure used for release flow rate (psig);
p. Release duration;
q. For potential design spill selections, include release height, orientation, rainout percentage, total vapor mass flow rate (lb/hr), de-inventory duration, and screening dispersion distance (ft); and
r. Comments, including any pump run out percentages used, as well as justifications or other details for the final design spills selected.

DS4. Is the largest size hole always used as the hole size in release modeling?

Not necessarily. For any defined maximum hole size, the applicant must demonstrate that that the hole size selected produces the greatest vapor dispersion distance when accounting for the mechanisms of flashing, jetting, aerosol formation, and rain-out. If a smaller hole size creates a larger vapor dispersion hazard distance, that smaller hole size should be used to define the design spill event. This applies to all single accidental leakage sources, including failures at piping, piping connections, and transfer hoses.

DS5. What are the proper release height and orientation to use for a design spill?

For each design spill identified, the release height should be the one that defines the largest hazard distances, bounded within the actual or anticipated heights of the equipment and piping.

Release orientation should be horizontal for each design spill unless a vertical orientation would produce higher consequences. Vertical orientations that provide higher consequences generally include:

- vertically upward for liquid releases with rainout greater than 25% (e.g., heavy hydrocarbons, pentane, etc.);
- vertically downward for gaseous releases (e.g., acid gas) ; and
- where mitigation measures would control or redirect the release, specific release orientations may be considered (e.g., pipe shrouding that directs a fluid downward, the downward direction may be applied).

A sensitivity analysis should be provided to demonstrate which release orientation scenario (horizontal, vertical upward, or vertical downward, as applicable) results in the largest hazard distance.

DS6. How are release locations defined?

For single-ply expansion joint or transfer hose failures, the release location can be identified at the specific point of that component in the LNG plant. For piping segments, the selected hole can occur at any location along the piping segment. If vapor barriers, shrouds, or pipe-in-pipe designs are used to reduce the vapor dispersion distance, locations potentially not impacted by the vapor barrier, shroud, or pipe-in-pipe should also be selected.

DS7. How do I determine the process conditions to evaluate for hazard modeling?

Process conditions should be based on heat and material balance modes of operation and design case (e.g., rich, lean, average, etc.) that produce the worst case dispersion results from flashing and jetting and liquid releases. The leakage sources from branch connections should be considered using the potential operational conditions along the pipe as well as the potential operational conditions that could be experienced at or near the branch pipe connection to a main process line. In cases that would reduce the back pressure on pump(s) or compressor(s), the flow rates should consider the potential increased pump or compressor flow determined by the pump and compressor curve(s) as detailed in DS10 and also consider the decrease in temperature and pressure during runout conditions.

DS8. What considerations should be given to system inventory and spill duration in the design spill calculations?

The applicant may need to demonstrate the selected design spill duration. The release modeling should account for the available system inventory (including piping, process vessels, storage vessels, and other process equipment) when calculating the design spill duration as follows:

a. Applicants may use a 10-minute spill duration if the process design includes acceptable detection, isolation, and shutdown.
b. For long and large-bore piping with a significant distance between isolation valves (emergency shutdown or manually or remotely operated), as well as releases from process or storage vessels, the dispersion modeling may continue beyond the 10-minute design spill duration to account for the inventory volume in the piping and the entire contents of any vessels at maximum design level(s), unless the dispersion modeling endpoint reaches its furthest extent in a shorter time.
c. A release duration of less than 10 minutes may be used for release scenarios where the available system inventory may be depleted in less than 10 minutes. The applicant may elect

this shorter duration based on demonstrable surveillance, shutdown, and isolation design with valve closures from emergency shutdowns or remote valve operation per NFPA 59A-2001. All scenario isolation valves must be protected from failure, including fire and external impacts. The shutdown system must meet a safety integrity level (SIL) 2 or SIL3 reliability design and maintenance requirements in accordance with the International Society of Automation (ISA) 84 standards.

DS9. How should I consider a release from a process or storage vessel in the design spill calculations?

For systems with a process or storage vessel, the applicant should first select the appropriate release scenarios that account for the pipe flow (normal operational or pump run out) from the piping connecting to a vessel, based on FAQs DS7 and DS10. Furthermore, a comparative release scenario should be provided using the process or storage pressure from the vessel. This pressurized release rate may be calculated using the orifice equation at full operational system pressure, including the hydrostatic head from the maximum liquid design level, for the entire design spill duration. This corresponding duration would last until the inventory that could be isolated by valves would be depleted. The applicant should then perform a comparative screening to determine whether the piping or the vessel-pressurized scenario would result in the worst case dispersion distance.

Alternatively, transient flow scenarios may be evaluated to more precisely account for the effects of demonstrable surveillance, shutdown, and de-inventorying of the piping and vessel(s) on the release rate. A transient flow scenario should account for the most significant leakage source release from piping and the vessel, taking into account the normal flow into the vessel and the pressurized head space in the vessel.

DS10. Do I need to consider pump run-out in release scenario calculations?

Applicants should use pump run-out (greater flow than in normal pump flow operations) in failure calculations if the pump design allows increases in flow as the discharge pressure is reduced, unless acceptable preventive measures are used that prevent the pump from run out conditions. Pump runout parameters are presented by the pump manufacturer as a pump curve that shows flow increasing as the discharge pressure decreases. If pump run-out flows are not known at the time of submittal, engineering estimates may be employed provisionally.

Acceptable preventive measures include pump interlocks or safety instrumented prevention systems that meet safety integrity level (SIL) 2 or SIL3 reliability design and maintenance requirements in accordance with the International Society of Automation (ISA) 84 standards.

DS11. Should multiple pumps be considered when calculating the greatest flow from a spill to size impoundments or when defining a single accidental leakage source event?

Where the greatest flow is potentially fed from multiple pumps, calculate the flow to size impoundments assuming that all pumps are running, unless acceptable preventive measures are used that prevent all pumps from running concurrently.

Where a piping system utilizes multiple pumps, calculate the design spill based on the total flow from all system pumps running, unless acceptable preventive measures are used that prevent or limit all pumps from running concurrently.

Acceptable preventive measures include pump interlocks or safety instrumented prevention systems that meet safety integrity level (SIL) 2 or SIL 3 reliability design and maintenance requirements in accordance with the International Society of Automation (ISA) 84 standards.

(H) Hazards and Hazards Modeling

H1. Other than the flammable vapor dispersion and thermal radiation from hazards associated with LNG, what other hazards should be evaluated in the siting analysis for an LNG plant?

According to NFPA 59A-2001 Paragraph 2.1.1(d), (incorporated by reference in 49 CFR Part 193), all hazards that can affect the safety of the public or plant personnel are to be considered. In addition to LNG, the applicant should consider hazards associated with flammable gases, flammable refrigerants, flammable or combustible liquids, or acutely toxic materials. If present at the LNG plant, hazards including vapor dispersion from liquid pools, vapor dispersion from jetting and flashing phenomena, thermal radiation from pool fires, thermal radiation from fires involving jetting and flashing phenomena (jet fires), overpressure from vapor cloud ignitions, toxic gas dispersion, and boiling liquid expanding vapor explosions (BLEVEs) involving pressurized storage vessels should be included in an LNG plant's hazard evaluation.

H2. My LNG plant includes some toxic materials. What considerations should be given to accidental releases of these materials and the associated hazard modeling?

While the hazards associated with toxic substances at an LNG plant are not prescriptively covered in 49 CFR Part 193, their consideration is required by NFPA 59A-2001 Paragraph 2.1.1(d) (incorporated by reference in 49 CFR Part 193), which requires that all hazards that can affect the safety of the public or plant personnel be considered.

Many toxic substances stored above certain quantities are regulated under Appendix A of the EPA's "Risk Management Program for Chemical Accidental Release Prevention" (RMP, 40 CFR 68) and OSHA's "Process Safety Management of Highly Hazardous Chemicals" (PSM, 29 CFR 1910.119). Compliance with EPA's RMP and OSHA's PSM regulations is a sufficient approach to comply with NFPA 59A Paragraph 2.1.1(d). PHMSA does not have authority to enforce EPA or OSHA regulations, but requires operator compliance with NFPA 59A Paragraph 2.1.1(d).

Consideration of toxic hazards must include dispersion modeling appropriate for the toxic substance and its behavior upon release, as well as incorporating safety measures of the design and operation of the facility. Applicants may propose alternative modeling methods to comply with NFPA 59A Paragraph 2.1.1(d) for toxic substances. The release scenario selection methodology should be consistent with the selection methodology defined in FAQs DS2 and DS4 through DS11. In addition, the dispersion modeling should consider a method to account for the potential combined impacts of toxic components (e.g., the principle used in the Compressed Gas Association P-20 methodology). The AEGL values are the preferred endpoints to be used in the calculations with an exposure duration corresponding to the release event, up to 1 hour. Because there are no specific exclusion zones that are to be defined for toxic materials, the offsite impacts at each proposed LNG plant will be evaluated on a case-by-case basis.

H3. Materials received, stored, or used at my LNG plant could generate overpressures from a vapor cloud explosion. What considerations should be given to vapor cloud explosions and the associated hazard modeling?

While explosion overpressure is not prescriptively covered in 49 CFR Part 193, its consideration is required by NFPA 59A-2001 Paragraph 2.1.1(d) (incorporated by reference in 49 CFR Part 193), which requires that all hazards that can affect the safety of the public or plant personnel be considered. Vapor cloud explosion modeling should involve consideration of vapor dispersion modeling results, evaluation of areas of confinement and congestion, and the potential reactivity of released materials. The use of the 1.0 psi overpressure endpoint is appropriate for explosion modeling, and is consistent with the EPA's "Risk Management Program for Chemical Accidental Release Prevention" (RMP, 40 CFR 68). Because there are no specific exclusion zones that are to be defined for explosion overpressure impacts, the offsite impacts at each proposed LNG plant will be evaluated on a case-by-case basis.

H4. What wind direction should be used in exclusion zone and other hazard calculations?

For most hazard calculations, the exclusion distance or hazard distance is calculated independent of wind direction. If the wind direction is important in the modeling methods used, the direction used should be toward the nearest property line. Additional wind directions may also need to be analyzed if the hazard could extend beyond other property lines or cause other unique hazards.

H5. Can an exclusion zone extend beyond the operator's LNG plant property line?

As long as the facility is in operation, the operator is responsible for assuring compliance with the limitations on land use within exclusion zones, according to the descriptions in NFPA 59A Sections 2.2.3.2, 2.2.3.3, and 2.2.3.4. For example, an exclusion zone that extends past a property line into a navigable body of water or onto a public road is typically acceptable. This may not hold true if that body of water contains a dock or pier that is not controlled by the operator of the LNG plant, or if another entity could erect a building or members of the public could assemble within the exclusion zone. It is possible to assure compliance by legal agreement with a property owner affected by the exclusion zone, such that the land use is restricted for the life of the LNG plant.

H6. In addition to DEGADIS 2.1 and FEM3A, Section 193.2059 Flammable vapor dispersion protection provides for the use of alternate models approved by US DOT PHMSA. What other models have been approved?

US DOT PHMSA has approved two additional models for the determination of vapor dispersion exclusion zones: FLACS 9.1 Release 2 (October 7, 2011) and PHAST-UDM Version 6.6 and 6. 7 (October 7, 2011). Each model has been validated for use in certain conditions in accordance with the Model Evaluation Protocol (MEP) as described in M. J. Ivings et al., Evaluating Vapor Dispersion Models for Safety Analysis of LNG Facilities Research Project: Technical Report (April 2007) (available at http://www.nfpa.org).

For detailed information regarding the conditions for which the models were validated, see PHMSA's final decision at:

FLACS http://www.regulations.gov/#!docketDetail;D=PHMSA-2011-0101

PHAST http://www.regulations.gov/#!docketDetail;D=PHMSA-2011-0075

H7. Does US DOT PHMSA prescribe source term models for flammable vapor dispersion modeling?

While PHMSA does not prescribe or approve source term models, the source term model must have a creditable scientific basis and must not ignore any phenomena that can influence vapor formation during discharge from containment, conveyance to an impoundment, and retention within the impoundment. In July, 2010 PHMSA communicated in interpretation PI-10-0021 that the SOURCE5 model does not satisfy the PHMSA requirements for a source term model. The interpretation can be viewed at:
http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=319134025ed5b210VgnVCM1000001ecb7898RCRD.

H8. Can mitigation measures be used in exclusion zone and other hazard calculations?

For most hazard calculations, passive mitigation measures are inherently acceptable, provided that their design and implementation can be technically supported and that they do not introduce other harmful consequences.

Active or procedural mitigation measures are generally not included exclusion zone or hazard zone calculations. However, PHMSA will review the proposed inclusion of such measures on a case-by-case basis, provided that proper supporting technical justification and documentation is submitted.

Revised: 7/25/2017

Frequently Asked Questions

https://www.phmsa.dot.gov/faqs/liquefied-natural-gas

October 23, 2017

(G) General

G1. The abundant supply of domestic natural gas is driving development of new ways to use, process, and transport LNG. Can PHMSA provide guidance as to which LNG facilities are regulated under 49 CFR Part 193?

The Pipeline Safety Statute codified in 49 U.S. Code § 60101, et seq, directs US DOT to establish and enforce standards for liquefied natural gas pipeline facilities. An LNG facility is a gas pipeline facility used for converting, transporting or storing liquefied natural gas. Many LNG facilities are subject to the regulatory and enforcement authority of the Department of Transportation through PHMSA. A simple but not complete test to determine if an LNG facility is regulated under 49 CFR Part 193 is to identify both the source and the consumer of the LNG. The facility is regulated under 49 CFR Part 193 if the LNG facility either receives from or delivers to a 49 CFR Part 192 pipeline.

49 CFR Part 193 does not apply to:

1. LNG facilities used by ultimate consumers of LNG or natural gas.
2. LNG facilities used in the course of natural gas treatment or hydrocarbon extraction that do not store LNG.
3. In marine cargo transfer systems and associated facilities, any matter other than siting pertaining to the system or facilities between the marine vessel and the last manifold (or, in the absence of a manifold, the last valve) located immediately before a storage tank.
4. Any LNG facility located in navigable waters (as defined in Section 3(8) of the Federal Power Act (16 U.S.C. 796(8)).

Operators should assume an LNG facility used in the transportation of gas by a 49 CFR Part 192 pipeline is regulated under 49 CFR Part 193 unless specifically exempted in Section 193.2001(b). LNG facilities may be regulated by PHMSA even though they are not regulated by the FERC. The 'ultimate consumer' provision provides a very limited exemption from 49 CFR Part 193. PHMSA interpretation # PI-10-0025 provides guidance. Here is an excerpt:

> *During the rulemaking that led to the adoption of § 193.2001(b)(1), OPS explained that the intent of that provision was to create an exception for "an LNG facility used by the ultimate consumer of the product". Likewise, in responding to a series of questions from a congressional committee, OPS stated that the exception in § 193.2001(b)(1), was designed for "small" facilities which are "generally located in industrial plants ... [to] serve as a supply of energy or feedstock for the plant." Unlike these examples, the Maine LMF facilities would be used to produce LNG for sale and distribution by truck, not solely for onsite consumption. Therefore, OPS concludes that your client's facilities would not qualify for the end-user exception in § 193.2001(b)(1).*

Follow this link for a map of LNG Plants regulated under 49 CFR Part 193 (except mobile and temporary). This document illustrates examples of LNG facilities that are or are not regulated under 49 CFR Part193.

G2. What agency or agencies have regulatory authority over the siting of LNG facilities?

There are more than 110 liquefied natural gas (LNG) facilities operating in the U.S. performing a variety of services. Most of these facilities store LNG for "peak shaving," where the LNG is vaporized and transported in gas transmission or gas distribution pipelines for periods of peak demand. There is significant growth in the number of facilities producing LNG as a transportation vehicle fuel for trucks, buses, trains, and ships. Depending on the location and use, several Federal agencies and State utility regulatory agencies may regulate an LNG facility.

For LNG import and export facilities located onshore, three Federal agencies share oversight for safety and security: the Federal Energy Regulatory Commission (FERC), the U.S. Coast Guard, and the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA). Under Section 3 of the Natural Gas Act of 1938, FERC is responsible for authorizing the siting and construction of onshore and near-shore LNG import or export facilities. Under Section 7 of the Natural Gas Act of 1938, FERC also issues certificates of public convenience and necessity for LNG facilities engaged in interstate natural gas transportation by pipeline. As required by the National Environmental Policy Act (NEPA), FERC prepares NEPA analyses for proposed LNG facilities under its jurisdiction. The Coast Guard has authority over the safety of LNG vessels and the marine transfer area, conducting Waterway Suitability Assessments to address navigation safety and port security issues associated with LNG ship traffic. PHMSA has authority to establish and enforce safety standards for onshore LNG facilities.

PHMSA's regulations for LNG facilities appear in Title 49, Part 193 of the Code of Federal Regulations (CFR). LNG facility applicants, when applying to FERC, are required to identify how their proposed facility would meet the siting requirements of 49 CFR Part 193. FERC consults with its cooperating agencies, including PHMSA, as needed. Once FERC approves a project and the applicant moves forward in the process, PHMSA inspects sites during and after construction, and during facility operation, and is responsible for taking enforcement action under Part 193 if necessary.

G3. As an operator, how do I submit an application to install a FERC regulated LNG facility?

The FERC is responsible for authorizing the siting and construction of onshore and near-shore LNG import or export facilities and LNG facilities engaged in interstate natural gas transportation by pipeline. As an operator of one of these types of facilities, you must coordinate with the FERC in the development of the Resource Reports required for the FERC application process. Information on Resource Reports 11 & 13, which deals with the engineering detail of the LNG facility, can be found in 18 CFR 380.12 (m) & (o).

G4. What types of LNG facilities require information submittal?

If an LNG facility requires FERC review and siting approval, PHMSA as a cooperating agency will require detailed information as described in these FAQs. Please refer to Subpart A of Part 193 for scope and applicability of PHMSA's regulations. There are regulations in Part 193 pertaining to siting, design, construction, equipment, maintenance, personnel qualifications and training, fire protection, and security. If the operator has questions or needs further guidance on the applicability of Part 193 to the facility in question, then the operator may contact PHMSA headquarters or the PHMSA Regional Offices. PHMSA's regional contact information is located here, or you may contact PHMSA's Director of Engineering as noted below under FAQ #G6.

G5. Does PHMSA have an application or permitting process for new or modified LNG facilities that are subject to the jurisdiction of Part 193 but does not require FERC review?

PHMSA does not require an application process and does not have authority for permitting LNG facilities. PHMSA requires LNG operators submit information to the National Registry of Pipeline and LNG Operators database 60 days prior to commencing construction. See FAQ #G10 below for more information.

LNG operators may be required to submit an application to the Federal Energy Regulatory Agency (FERC) or the appropriate state agency. Operators must notify the State Pipeline Safety Agencies at least 2 weeks prior to the installation of portable LNG facilities and provide information prescribed in §193.2019 (b).

Determining how to comply with 49 CFR 193 is the responsibility of the operator. PHMSA is available to answer your questions. Please contact Ken Lee, Director, Engineering and Research Division (202) 366-2694 or by email kenneth.lee@dot.gov.

G6. Since PHMSA is a cooperating agency in the FERC siting process, do I need to provide anything directly to PHMSA in order to help expedite the application process?

Yes. If a facility is subject to Part 193 (see reply to FAQ #G3 above), then in order for PHMSA to perform an in-depth review and analysis, you should copy and forward specific items for evaluation. You should send all application materials directly to FERC, but you should also submit to PHMSA hard and digital copies of the documents noted in these FAQs to aid PHMSA in its review. Review of your application will be delayed unless you promptly submit to PHMSA substantially complete application materials. Please also be aware that PHMSA will need detailed materials without any redaction, regardless of security sensitive or proprietary information, in order to conduct a full review. If you believe your materials are security sensitive or proprietary in any way, please mark them accordingly.

Materials noted below should be addressed to:

U.S. Department of Transportation
Pipeline & Hazardous Materials Safety Administration
Kenneth Lee – Director
Engineering and Research Division
East Building, Room E22-334
1200 New Jersey Avenue, SE
Washington, DC 20590
Telephone: (202) 366-2694
Email: kenneth.lee@dot.gov

G7. What specific items should be sent to PHMSA?

The applicant should submit a Design Spill Package directly to PHMSA to aid in the review process. Detailed engineering materials are required as part of the Design Spill Package.

The Design Spill Package should include:

a. Project description, background, purpose and details describing the proposed facility;
b. Hazard reports, including any attachments and referenced reports;
c. Facility location map(s), topography map(s), and site aerial photography;
d. Engineering drawings including an overall plot plan showing the project's property boundary and unit plot plans for each process area or system showing the location and elevation of major

equipment. Each area and piece of equipment should be clearly labeled. The unit plot plans should be detailed enough to allow for measurement of distances between various components with a reasonable degree of accuracy. The smallest scale submitted should be no smaller than 1-inch to 100-feet (1:1200);

e. Piping and instrument drawings (P&ID);
f. Process Flow Diagrams (PFD);
g. Heat and Material Balance Sheets (H&MB);
h. Piping Inventory Table;
i. Pump and compressor curves for pumps and compressors used for hazardous fluid service (as available);
j. Sketch on plot plan showing expected locations and elevations of major potential single accidental leakage sources;
k. Dimensions, capacities, and thermal properties for any impoundments associated with this project;
l. Design details for mitigation measures, including vapor barriers and pipe-in-pipe systems; and
m. The summary report of all input and output parameters for computer program simulations (i.e., PHAST) should be included.
n. Note: The summary report will provide the design spill criteria and screening assessment that was used.

If additional information is required, PHMSA will work with the applicant on additional information submittals.

G8. After I submit information to PHMSA, how long will the review process take?

The duration of the review process varies. There are a variety of factors which influence the timeline for review and approval, including the volume of previously submitted applications, where the applicant is in the siting process, and the completeness of the submitted information. PHMSA will acknowledge receipt of the application and will begin the review process. PHMSA will contact the applicant during the review process to resolve any outstanding needs or questions.

G9. After I submit the required information to PHMSA, what information do I need to file on the FERC docket?

For those projects under FERC jurisdiction, all information submitted to PHMSA should be filed on the FERC docket. PHMSA will work with the applicant to review the information. If revisions or edits are necessary, the applicant will be instructed to file an addendum to the FERC docket.

G10. A FERC regulation (18 CFR § 385.2201) prohibits off-the-record communications in a contested, on-the-record proceeding. The rule is designed to limit communications between a "decisional employee" at FERC and persons outside the Commission. How do FERC's restrictions on ex parte communication affect PHMSA's communications with LNG project applicants?

The purpose of the rule is to ensure the integrity and fairness of the Commission's decisional process, and to prevent off-the-record communications relative to the merits of a Commission proceeding between FERC decisional employees and entities outside of the Commission. Generally, communications regarding Part 193 compliance between PHMSA and a party before the Commission do not violate FERC's ex parte rules. However, PHMSA takes care to not act as a conduit for otherwise unpermitted communications. Some communication between PHMSA and a facility applicant is expected, but PHMSA restricts those communications to matters that FERC has explicitly referred to PHMSA. In accordance with the FERC's public disclosure requirements and FERC's responsibilities under its ex parte regulations, PHMSA, as a

cooperating agency, cannot release pre decisional information related to the NEPA analysis (such as working drafts of NEPA documents and PHMSA comments on those working drafts).

If PHMSA needs additional information from an applicant to resolve a matter that FERC has referred to us, PHMSA will advise FERC and the applicant of what additional information is needed and request that it be submitted to FERC's docket.

G11. How do operators notify PHMSA that construction, upgrade, or refurbishment of an LNG facility will be commencing?

New operators must first obtain an Operator Identification Number (OPID). To obtain on OPID, an operator must complete an OPID Assignment Request DOT Form PHMSA F 1000.1 through the National Registry of Pipeline and LNG Operators in accordance with §191.22(a).

Each operator of an LNG plant or LNG facility is required to submit notification of specified events to PHMSA in accordance with §191.22(c). Operators must use the Operator Registry Notification (Form PHMSA F 1000.2) to report new construction, asset-changing or program-changing events associated with LNG facilities. Within Form PHMSA F 1000.2, operators planning to begin new construction, refurbishment or an upgrade project, regardless of cost, select a Type J – New Construction Notification.

Construction notifications are required to be submitted 60 days prior to the "event." On September 12, 2014, PHMSA published an Advisory Bulletin describing the activities that constitute the "event" of construction, which determines the due date for the notification. The types of construction events that would initiate a notification submittal include material purchasing and manufacturing, right-of-way acquisition, construction equipment move-in activities, onsite or offsite fabrications, or right-of-way clearing, grading and ditching.

Click here to view LNG Construction Report – Notification Type J in a new window.

Note that operators have requirements for the reporting of incidents, safety-related conditions, and annual pipeline summary data in accordance with §191.1 and to submit mapping data to the National Pipeline Mapping System (NPMS) in accordance with §191.7. Requests for OPID, construction notifications, and reporting must be made online via the PHMSA portal, using assigned user name and password, unless an alternate method is approved. Copies of the forms and instructions for PHMSA F 7100.3 (Incident Report) and PHMSA F 7100.3-1 (Annual Report) can be found on the Pipeline Safety Community Web Page at https://www.phmsa.dot.gov/pipeline/liquified-naturalgas/forms/pipeline-forms. Contact the PHMSA Information Resources Manager at (202) 366-8075 if you have questions. For information about making an NPMS submission, see https://www.npms.phmsa.dot.gov/PipelineOperator.aspx.

G12. What are the siting requirements for small LNG facilities that have an aggregate storage capacity of 70,000 gallons or less on one site?

The writer asks, "Part 193 has requirements for thermal radiation exclusion and vapor-gas dispersion exclusion zones that are required for *each* LNG container and transfer system, but NFPA 59A, 2001 edition has Table 2.2.4.1 *Distances from Impoundment Areas to Buildings and Property Lines* for small LNG facilities with total onsite storage capacity of 70,000 gallons LNG or less. Does NFPA 59A, 2001 edition, Chapter 2, Plant Siting and Layout, paragraph 2.2.3.7 which allows use of Table 2.2.4.1 'Distances from Impoundment Areas to Buildings and Property Lines' *conflict* with Part 193 Subpart B – Siting Requirements?"

Part 193 siting requirements include the determination of exclusion zones, areas in which the operator or a government agency legally controls all activities. The exclusion zones are determined by complying with §193.2057 *Thermal radiation protection* and §193.2059 *Flammable vapor-gas dispersion protection*. These sections incorporate by reference NFPA 59A paragraph 2.2.3.2 (thermal radiation distance) and paragraphs 2.2.3.3 and 2.2.3.4 (vapor dispersion distance). NFPA 59A paragraph 2.2.3.7 is not provided as an alternative to §193.2057 and §193.2059 for permanent facilities.

Under §193.2019, mobile and temporary LNG facilities need not meet the requirements of Part 193 (including sections 193.2057 and 193.2059) if they comply with the applicable sections of NFPA 59A that is incorporated by reference. NFPA 59A paragraph 2.3.4 covers the requirements for such facilities. 2.3.4(g) references Table 2.2.4.1 for the spacing guidelines at mobile and temporary facilities. When table 2.2.4.1 is used for compliance with paragraph 2.3.4 (g), the aggregate capacity of the multiple LNG containers on the temporary site is to be used to determine facility spacing.

(D) Design

D1. What wind speed should be used in LNG facility equipment design calculations?

Wind forces are addressed in 49 CFR § 193.2067, which requires that LNG facilities be designed to withstand the direct effect of wind forces without loss of structural or functional integrity. Structural engineering design is typically performed using 3-second gust wind speeds in miles-per-hour (mph).

For shop fabricated containers of LNG or other hazardous fluids with a capacity of not more than 70,000 gallons, the wind forces at the location of the specific facility must be based on applicable wind load data in ASCE/SEI 7-05.

For all other LNG facilities, the wind forces at the location of the specific facility must be based on one of the following:

a. an assumed sustained wind velocity of not less than 150 MPH; or
b. a sustained wind velocity of less than 150 MPH that is justified by adequate supportive data and found acceptable by the Administrator; or
c. the most critical combination of wind velocity and duration, with respect to the effect on the structure, having a probability of exceedance in a 50-year period of 0.5 percent or less, if adequate wind data are available and the probabilistic methodology is reliable.

For most structural engineering design calculations, the sustained wind velocity is converted to 3-second gust wind speed using a conservative method based on sound engineering principles. The Durst curve is an acceptable conversion method in ASCE/SEI 7-05, Chapter C6. Using this method, a sustained wind velocity of 150 mph is equivalent to a 183 mph 3-second gust. Applicants should also design all facilities to meet all applicable local or state building codes.

D2. To what parts of the facility does § 193.2067(b)(2) apply?

This paragraph applies to all LNG facilities other than those that are described in §193.2067(b)(1). The term "LNG facility" is defined in 49 CFR §193.2007. The parts of the LNG plant considered for compliance with this design requirement include all parts used when liquefying natural gas or transferring, storing, or vaporizing liquefied natural gas. This includes piping and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation.

D3. Should the wind speed design criteria of 193.2067 be applied to vapor barriers at the LNG plant?

Since vapor barriers are installed for the purpose of reducing the extent of exclusion zones, they are a part of the LNG facilities and subject to the regulatory wind speed requirements. Vapor barriers must be functional while the LNG facility is in operation.

D4. Can vacuum jacketed piping be used in an LNG plant and may the outer pipe be used for LNG impoundment?

The applicant must fully document any application of vacuum jacketed pipe (VJP) or vacuum insulated pipe (VIP). The design details of the piping as well as the locations where it is to be used must be provided. In cases where the VJP or VIP may affect the prescribed design spills, impoundment determinations, or other hazard calculations, the applicant must fully justify the position and approach being taken. PHMSA will review these applications on a case-by-case basis, and a special permit (see 49 CFR Section 190.341) may be required.

D5. As an operator of a LNG Facility, our pressure vessels will be designed and fabricated to the current American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (BPVC). This differs from the requirements of 49 C.F.R. Part 193. How can I ensure our pressure vessels comply with Part 193?

To comply with the requirements of 49 C.F.R. Part 193, each applicant for a LNG facility designed after March 10, 2004, must do one of the following:

- Ensure compliance with NFPA 59A-2001, Paragraph 3.4.2, using the 1992 ASME BPVC; or,
- Submit an application for a special permit in accordance with 49 C.F.R. § 190.341; or,
- Demonstrate an equivalent level of safety as described in NFPA 59A-2001, Section 1.2.

Any deviation from the above requirements for pressure vessels by an operator of a LNG facility will require submittal of technical documentation for review by PHMSA on a case-by-case basis.

D6. As a design engineering firm or as an operator of a LNG facility, if our pressure vessels are designed and fabricated to the current American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (BPVC), which methods may I use to demonstrate safety equivalency as described in NFPA 59A-2001, Section 1.2, and as mentioned in FAQ D5?

Refer to NFPA 59A (2001), Section 1.2 Equivalency, which states:

Nothing in this standard is intended to prevent the use of systems, methods, or devices of equivalent or superior quality, strength, fire resistance, effectiveness, durability, and safety over those prescribed by this standard. Technical documentation shall be submitted to the authority having jurisdiction to demonstrate equivalency. The system, method, or device shall be approved for the intended purpose by the authority having jurisdiction.

When pressure vessels are designed and fabricated for use under Part 193 by using a more recent edition of the ASME BPVC than the 1992 version, the Operator is responsible to document the method used to determine equivalency and make this technical documentation available to PHMSA upon request. PHMSA will accept one of the following methods to demonstrate equivalency in accordance with NFPA 59A-2001, Section 1.2:

- Pressure vessels may be designed and fabricated to meet the requirements for test pressure and design margin factors found in the 1992 edition of the ASME BPVC; or,
- The maximum allowable working pressure (MAWP) for the pressure vessels may be reduced by the amount that results in a test pressure for all pressure vessels meeting the requirements in the 1992 edition of the ASME BPVC Section VIII, Division 1 or Division 2; or,
- Longitudinal, circumferential, nozzle-to-shell, tube sheet, header box, and nozzle-to-box header welds may be inspected by nondestructive examination (NDE). All longitudinal and circumferential welds and nozzle-to-shell welds for process nozzles six (6) inches or larger in diameter must be subject to 100% NDE. Accepted NDE methods are radiograph testing (RT), ultrasonic testing (UT), magnetic particle testing (MPT or MT), and dye penetrant testing (DPT or PT) along the entire weld length in accordance with the applicable sections of the current ASME Section VIII or other applicable standards. Longitudinal and circumferential welds must be subject to radiographic or ultrasonic testing; or,
- The operator of the LNG facility may develop, document, and implement a systematic approach, with annual inspections not to exceed 15-months, to ensure the long-term integrity of all its pressure vessels and pressure-relieving devices protecting these vessels within the LNG facility. The asset management procedure must incorporate and comply with a current recognized and generally accepted American National Standards Institute (ANSI) standard such as the American Petroleum Institute (API) 510, "Pressure Vessel Inspection Code: In-service Inspection, Rating, Repair, and Alteration," 10th Edition. The procedures must be adopted into the operator's operations and maintenance (O&M) manual. The procedures must be updated, as needed, for the continuous, effective management of pressure vessel integrity that must include over pressure protection, corrosion, pipe wall thickness loss, cracking on both girth and longitudinal welds and steel body, loading stresses such as loads on nozzles from piping, valves, other components, and soil settlement and environmental deterioration of the pressure vessel due to weathering. Adoption and implementation of a pressure vessel asset management plan is in addition to the existing minimum requirements for operations, maintenance, and personnel qualifications and training found in 49 CFR Part 193 and NFPA 59A-2001. The operator must maintain all records and procedures for design, construction, testing, repairs, and O&M activities as required in API 510. The "Risk Based Inspection" option in Section 6.3 of API 510 is not an acceptable O&M inspection and evaluation method; or,
- The operator may submit to PHMSA another system, method, or device that is intended to demonstrate equivalency for evaluation and review on a case-by-case basis.

(DS) Design Spill Determination

DS1. The criteria and methodology used to identify single accidental leakage sources (SALS) to establish siting for my LNG facility were based on the failure rate table methodology. Do I need to submit a new or revised Design Spill Package to PHMSA based on the current SALS methodology?

No. PHMSA will not require the applicant to submit a new or revised Design Spill Package and will not retroactively apply the current SALS methodology to facilities that have received a previous PHMSA correspondence of no objection to their methodology for determining the SALS for design spills used in establishing the 49 CFR Part 193 siting requirements. If the applicant chooses to modify the design spills that were previously determined to be in compliance with Part 193 siting requirements, PHMSA will require an updated Design Spill Package as described in these FAQs. For those projects under FERC jurisdiction, the applicant will also need to file the updated information submitted to PHMSA on the FERC docket.

DS2. 49 CFR 193 requires that design spills for an LNG plant be selected according to NFPA 59A-2001 Paragraph 2.2.3.5. NFPA 59A requires the evaluation of accidental flow from "any single accidental leakage source" (SALS) but does not define this term. How should I select SALS events in an LNG plant?

For piping and equipment that handle LNG, flammable refrigerants, toxic components, and any other hazardous fluid, leakage sources may be chosen using the following guidelines. The SALS selection methodology, below, is applied to determine the maximum hole sizes of interest for the most significant releases of each hazardous fluid in each portion of the LNG plant. (The SALS selections are one component of design spill definition. Please refer to other FAQs for additional design spill definition topics.)

A. For piping segments, including transfer arms and double-ply construction expansion bellows, that are:
   1. Greater than or equal to 6 inches in diameter, a hole of 2 inches in diameter is applied at any location along the piping segment; and
   2. Less than 6 inches in diameter, a full-bore rupture (guillotine failure) is applied at any location along the piping segment.
B. For single-ply construction expansion bellows, a hole size equivalent to a full-bore rupture of the diameter of the expansion joint is applied;
C. For pipe-in-pipe systems, an unobstructed release from an equivalent 1-inch diameter hole may be applied at the operating conditions of the inner pipe when:
   1. The system complies with NFPA 59A (2016) Section 9.11;
   2. The outer pipe is able to withstand the thermal shock, mechanical forces, and pressure loads of any single accidental leakage source from A and B above applied to the inner pipe; and
   3. Design, fabrication, examination, and testing of the pipe-in-pipe system, including calculations, can be demonstrated.

The selection of any alternate hole size or release scenario definition will be reviewed on a case-by-case basis in lieu of the criteria defined above; and

D. For transfer hoses, a hole size equivalent to a full-bore rupture of the transfer hose is applied.

DS3. PHMSA reviews the design criteria for design spills on a case-by- case basis to determine compliance with Part 193. What information is required to assist PHMSA in its determination of the design spill criteria acceptable for use?

Applicants must provide a piping inventory table of LNG plant components in hazardous or flammable fluid service. At a minimum, the table should include piping of 2 inches in diameter and larger, as well as transfer hoses. The inventory table should be submitted in Excel (*.XL*) format. Separate tabs or lists should be used for each type of hazardous fluid, with demarcation of all of the final design spill selections. The table should include the following information:

a. Line segment scenario number to identify the leakage source scenario;
b. Description of line segment purpose (LNG rundown header, KO Drum drain, relief valve inlet, level gauge instrument connection, etc.);
c. General plant area or service (e.g. liquefaction train, refrigerant storage, marine area, etc.), unless the entire project is confined to one area;
d. Beginning point location (e.g., exchanger outlet flange) for each line;
e. Ending point location (e.g., pump suction nozzle) for each line;
f. Line diameter;

g. Hazardous fluid service (LNG, natural gas, refrigerants (such as propane, ethane, mixed refrigerant), ammonia, natural gas liquids (NGL) or gas condensate, acid gas (containing hydrogen sulfide), etc.);
h. P&ID drawing number reference(s) for each segment;
i. Piping line designation on P&ID
j. Fluid conditions within the line segment (e.g., fluid phase (liquid or vapor); density (lb/ft3); pressure (psig); temperature (°F); mass flow rate, (lb/hr); composition of mixed refrigerants, NGL/condensates, acid gas (mol%));
k. Process flow diagram and corresponding heat and material balance stream number;
l. Heat and material balance case selection;
m. Leakage source hole size;
n. Calculated total release flow rate (lb/hr);
o. Calculated depressurization or equilibrium pressure used for release flow rate (psig);
p. Release duration;
q. For potential design spill selections, include release height, orientation, rainout percentage, total vapor mass flow rate (lb/hr), de-inventory duration, and screening dispersion distance (ft); and
r. Comments, including any pump run out percentages used, as well as justifications or other details for the final design spills selected.

DS4. Is the largest size hole always used as the hole size in release modeling?

Not necessarily. For any defined maximum hole size, the applicant must demonstrate that that the hole size selected produces the greatest vapor dispersion distance when accounting for the mechanisms of flashing, jetting, aerosol formation, and rain-out. If a smaller hole size creates a larger vapor dispersion hazard distance, that smaller hole size should be used to define the design spill event. This applies to all single accidental leakage sources, including failures at piping, piping connections, and transfer hoses.

DS5. What are the proper release height and orientation to use for a design spill?

For each design spill identified, the release height should be the one that defines the largest hazard distances, bounded within the actual or anticipated heights of the equipment and piping.

Release orientation should be horizontal for each design spill unless a vertical orientation would produce higher consequences. Vertical orientations that provide higher consequences generally include:

- vertically upward for liquid releases with rainout greater than 25% (e.g., heavy hydrocarbons, pentane, etc.);
- vertically downward for gaseous releases (e.g., acid gas) ; and
- where mitigation measures would control or redirect the release, specific release orientations may be considered (e.g., pipe shrouding that directs a fluid downward, the downward direction may be applied).

A sensitivity analysis should be provided to demonstrate which release orientation scenario (horizontal, vertical upward, or vertical downward, as applicable) results in the largest hazard distance.

DS6. How are release locations defined?

For single-ply expansion joint or transfer hose failures, the release location can be identified at the specific point of that component in the LNG plant. For piping segments, the selected hole can occur at any location along the piping segment. If vapor barriers, shrouds, or pipe-in-pipe designs are used to reduce the vapor dispersion distance, locations potentially not impacted by the vapor barrier, shroud, or pipe-in-pipe should also be selected.

DS7. How do I determine the process conditions to evaluate for hazard modeling?

Process conditions should be based on heat and material balance modes of operation and design case (e.g., rich, lean, average, etc.) that produce the worst case dispersion results from flashing and jetting and liquid releases. The leakage sources from branch connections should be considered using the potential operational conditions along the pipe as well as the potential operational conditions that could be experienced at or near the branch pipe connection to a main process line. In cases that would reduce the back pressure on pump(s) or compressor(s), the flow rates should consider the potential increased pump or compressor flow determined by the pump and compressor curve(s) as detailed in DS10 and also consider the decrease in temperature and pressure during runout conditions.

DS8. What considerations should be given to system inventory and spill duration in the design spill calculations?

The applicant may need to demonstrate the selected design spill duration. The release modeling should account for the available system inventory (including piping, process vessels, storage vessels, and other process equipment) when calculating the design spill duration as follows:

A. Applicants may use a 10-minute spill duration if the process design includes acceptable detection, isolation, and shutdown.
B. For long and large-bore piping with a significant distance between isolation valves (emergency shutdown or manually or remotely operated), as well as releases from process or storage vessels, the dispersion modeling may continue beyond the 10-minute design spill duration to account for the inventory volume in the piping and the entire contents of any vessels at maximum design level(s), unless the dispersion modeling endpoint reaches its furthest extent in a shorter time.
C. A release duration of less than 10 minutes may be used for release scenarios where the available system inventory may be depleted in less than 10 minutes. The applicant may elect this shorter duration based on demonstrable surveillance, shutdown, and isolation design with valve closures from emergency shutdowns or remote valve operation per NFPA 59A-2001. All scenario isolation valves must be protected from failure, including fire and external impacts. The shutdown system must meet a safety integrity level (SIL) 2 or SIL3 reliability design and maintenance requirements in accordance with the International Society of Automation (ISA) 84 standards.

DS9. How should I consider a release from a process or storage vessel in the design spill calculations?

For systems with a process or storage vessel, the applicant should first select the appropriate release scenarios that account for the pipe flow (normal operational or pump run out) from the piping connecting to a vessel, based on FAQs DS7 and DS10. Furthermore, a comparative release scenario should be provided using the process or storage pressure from the vessel. This pressurized release rate may be calculated using the orifice equation at full operational system pressure, including the hydrostatic head from the maximum liquid design level, for the entire design spill duration. This corresponding duration would last until the inventory that could be isolated by valves would be depleted. The applicant should then perform a comparative screening to determine whether the piping or the vessel-pressurized scenario would result in the worst case dispersion distance.

Alternatively, transient flow scenarios may be evaluated to more precisely account for the effects of demonstrable surveillance, shutdown, and de-inventorying of the piping and vessel(s) on the release rate.

A transient flow scenario should account for the most significant leakage source release from piping and the vessel, taking into account the normal flow into the vessel and the pressurized head space in the vessel.

DS10. Do I need to consider pump run-out in release scenario calculations?

Applicants should use pump run-out (greater flow than in normal pump flow operations) in failure calculations if the pump design allows increases in flow as the discharge pressure is reduced, unless acceptable preventive measures are used that prevent the pump from run out conditions. Pump runout parameters are presented by the pump manufacturer as a pump curve that shows flow increasing as the discharge pressure decreases. If pump run-out flows are not known at the time of submittal, engineering estimates may be employed provisionally.

Acceptable preventive measures include pump interlocks or safety instrumented prevention systems that meet safety integrity level (SIL) 2 or SIL3 reliability design and maintenance requirements in accordance with the International Society of Automation (ISA) 84 standards.

DS11. Should multiple pumps be considered when calculating the greatest flow from a spill to size impoundments or when defining a single accidental leakage source event?

Where the greatest flow is potentially fed from multiple pumps, calculate the flow to size impoundments assuming that all pumps are running, unless acceptable preventive measures are used that prevent all pumps from running concurrently.

Where a piping system utilizes multiple pumps, calculate the design spill based on the total flow from all system pumps running, unless acceptable preventive measures are used that prevent or limit all pumps from running concurrently.

Acceptable preventive measures include pump interlocks or safety instrumented prevention systems that meet safety integrity level (SIL) 2 or SIL 3 reliability design and maintenance requirements in accordance with the International Society of Automation (ISA) 84 standards.

(H) Hazards and Hazards Modeling

H1. Other than the flammable vapor dispersion and thermal radiation from hazards associated with LNG, what other hazards should be evaluated in the siting analysis for an LNG plant?

According to NFPA 59A-2001 Paragraph 2.1.1(d), (incorporated by reference in 49 CFR Part 193), all hazards that can affect the safety of the public or plant personnel are to be considered. In addition to LNG, the applicant should consider hazards associated with flammable gases, flammable refrigerants, flammable or combustible liquids, or acutely toxic materials. If present at the LNG plant, hazards including vapor dispersion from liquid pools, vapor dispersion from jetting and flashing phenomena, thermal radiation from pool fires, thermal radiation from fires involving jetting and flashing phenomena (jet fires), overpressure from vapor cloud ignitions, toxic gas dispersion, and boiling liquid expanding vapor explosions (BLEVEs) involving pressurized storage vessels should be included in an LNG plant's hazard evaluation.

H2. My LNG plant includes some toxic materials. What considerations should be given to accidental releases of these materials and the associated hazard modeling?

While the hazards associated with toxic substances at an LNG plant are not prescriptively covered in 49 CFR Part 193, their consideration is required by NFPA 59A-2001 Paragraph 2.1.1(d) (incorporated by reference in 49 CFR Part 193), which requires that all hazards that can affect the safety of the public or plant personnel be considered.

Many toxic substances stored above certain quantities are regulated under Appendix A of the EPA's "Risk Management Program for Chemical Accidental Release Prevention" (RMP, 40 CFR 68) and OSHA's "Process Safety Management of Highly Hazardous Chemicals" (PSM, 29 CFR 1910.119). Compliance with EPA's RMP and OSHA's PSM regulations is a sufficient approach to comply with NFPA 59A Paragraph 2.1.1(d). PHMSA does not have authority to enforce EPA or OSHA regulations, but requires operator compliance with NFPA 59A Paragraph 2.1.1(d).

Consideration of toxic hazards must include dispersion modeling appropriate for the toxic substance and its behavior upon release, as well as incorporating safety measures of the design and operation of the facility. Applicants may propose alternative modeling methods to comply with NFPA 59A Paragraph 2.1.1(d) for toxic substances. The release scenario selection methodology should be consistent with the selection methodology defined in FAQs DS2 and DS4 through DS11. In addition, the dispersion modeling should consider a method to account for the potential combined impacts of toxic components (e.g., the principle used in the Compressed Gas Association P-20 methodology). The AEGL values are the preferred endpoints to be used in the calculations with an exposure duration corresponding to the release event, up to 1 hour. Because there are no specific exclusion zones that are to be defined for toxic materials, the offsite impacts at each proposed LNG plant will be evaluated on a case-by-case basis.

H3. Materials received, stored, or used at my LNG plant could generate overpressures from a vapor cloud explosion. What considerations should be given to vapor cloud explosions and the associated hazard modeling?

While explosion overpressure is not prescriptively covered in 49 CFR Part 193, its consideration is required by NFPA 59A-2001 Paragraph 2.1.1(d) (incorporated by reference in 49 CFR Part 193), which requires that all hazards that can affect the safety of the public or plant personnel be considered. Vapor cloud explosion modeling should involve consideration of vapor dispersion modeling results, evaluation of areas of confinement and congestion, and the potential reactivity of released materials. The use of the 1.0 psi overpressure endpoint is appropriate for explosion modeling, and is consistent with the EPA's "Risk Management Program for Chemical Accidental Release Prevention" (RMP, 40 CFR 68). Because there are no specific exclusion zones that are to be defined for explosion overpressure impacts, the offsite impacts at each proposed LNG plant will be evaluated on a case-by-case basis.

H4. What wind direction should be used in exclusion zone and other hazard calculations?

For most hazard calculations, the exclusion distance or hazard distance is calculated independent of wind direction. If the wind direction is important in the modeling methods used, the direction used should be toward the nearest property line. Additional wind directions may also need to be analyzed if the hazard could extend beyond other property lines or cause other unique hazards.

H5. Can an exclusion zone extend beyond the operator's LNG plant property line?

As long as the facility is in operation, the operator is responsible for assuring compliance with the limitations on land use within exclusion zones, according to the descriptions in NFPA 59A Sections 2.2.3.2, 2.2.3.3, and 2.2.3.4. For example, an exclusion zone that extends past a property line into a navigable body of water or onto a public road is typically acceptable. This may not hold true if that body of water contains a dock or pier that is not controlled by the operator of the LNG plant, or if another entity could erect a building or members of the public could assemble within the exclusion zone. It is possible to assure compliance by legal agreement with a property owner affected by the exclusion zone, such that the land use is restricted for the life of the LNG plant.

H6. In addition to DEGADIS 2.1 and FEM3A, Section 193.2059 Flammable vapor dispersion protection provides for the use of alternate models approved by US DOT PHMSA. What other models have been approved?

US DOT PHMSA has approved two additional models for the determination of vapor dispersion exclusion zones: FLACS 9.1 Release 2 (Oct. 7, 2011) and PHAST-UDM Version 6.6 and 6. 7 (Oct. 7, 2011). Each model has been validated for use in certain conditions in accordance with the Model Evaluation Protocol (MEP) as described in M. J. Ivings et al., Evaluating Vapor Dispersion Models for Safety Analysis of LNG Facilities Research Project: Technical Report (Apr. 2007) (available at http://www.nfpa.org/).

For detailed information regarding the conditions for which the models were validated, see PHMSA's final decision at:

FLACS http://www.regulations.gov/#%21docketDetail;D=PHMSA-2011-0101

PHAST http://www.regulations.gov/#%21docketDetail;D=PHMSA-2011-0075

H7. Does US DOT PHMSA prescribe source term models for flammable vapor dispersion modeling?

While PHMSA does not prescribe or approve source term models, the source term model must have a creditable scientific basis and must not ignore any phenomena that can influence vapor formation during discharge from containment, conveyance to an impoundment, and retention within the impoundment. In July, 2010 PHMSA communicated in interpretation PI-10-0021 that the SOURCE5 model does not satisfy the PHMSA requirements for a source term model. The interpretation can be viewed at: https://www.phmsa.dot.gov/regulations/title49/interp/PI-10-0021.

H8. Can mitigation measures be used in exclusion zone and other hazard calculations?

For most hazard calculations, passive mitigation measures are inherently acceptable, provided that their design and implementation can be technically supported and that they do not introduce other harmful consequences.

Active or procedural mitigation measures are generally not included exclusion zone or hazard zone calculations. However, PHMSA will review the proposed inclusion of such measures on a case-by-case basis, provided that proper supporting technical justification and documentation is submitted.

Updated: 10/23/2017

Frequently Asked Questions

https://www.phmsa.dot.gov/faqs/liquefied-natural-gas

July 25, 2018

(G) General

G1. The abundant supply of domestic natural gas is driving development of new ways to use, process, and transport LNG. Can PHMSA provide guidance as to which LNG facilities are regulated under 49 CFR Part 193?

The Pipeline Safety Statute codified in 49 U.S. Code § 60101, et seq, directs US DOT to establish and enforce standards for liquefied natural gas pipeline facilities. An LNG facility is a gas pipeline facility used for converting, transporting or storing liquefied natural gas.

Many LNG facilities are subject to the regulatory and enforcement authority of the Department of Transportation through PHMSA. A simple but not complete test to determine if an LNG facility is regulated under 49 CFR Part 193 is to identify both the source and the consumer of the LNG. The facility is regulated under 49 CFR Part 193 if the LNG facility either receives from or delivers to a 49 CFR Part 192 pipeline.

49 CFR Part 193 does not apply to:

1. LNG facilities used by ultimate consumers of LNG or natural gas.
2. LNG facilities used in the course of natural gas treatment or hydrocarbon extraction that do not store LNG.
3. In marine cargo transfer systems and associated facilities, any matter other than siting pertaining to the system or facilities between the marine vessel and the last manifold (or, in the absence of a manifold, the last valve) located immediately before a storage tank.
4. Any LNG facility located in navigable waters (as defined in Section 3(8) of the Federal Power Act (16 U.S.C. 796(8)).

Operators should assume an LNG facility used in the transportation of gas by a 49 CFR Part 192 pipeline is regulated under 49 CFR Part 193 unless specifically exempted in Section 193.2001(b). LNG facilities may be regulated by PHMSA even though they are not regulated by the FERC. The 'ultimate consumer' provision provides a very limited exemption from 49 CFR Part 193. PHMSA interpretation # PI-10-0025 provides guidance. Here is an excerpt:

> *During the rulemaking that led to the adoption of § 193.2001(b)(1), OPS explained that the intent of that provision was to create an exception for "an LNG facility used by the ultimate consumer of the product". Likewise, in responding to a series of questions from a congressional committee, OPS stated that the exception in § 193.2001(b) (1), was designed for "small" facilities which are "generally located in industrial plants ... [to] serve as a supply of energy or feedstock for the plant." Unlike these examples, the Maine LMF facilities would be used to produce LNG for sale and distribution by truck, not solely for onsite consumption. Therefore, OPS concludes that your client's facilities would not qualify for the end-user exception in § 193.2001(b)(1).*

Follow this link for a map of LNG Plants regulated under 49 CFR Part 193 (except mobile and temporary). This document illustrates examples of LNG facilities that are or are not regulated under 49 CFR Part193.

G2. What agency or agencies have regulatory authority over the siting of LNG facilities?

There are more than 110 liquefied natural gas (LNG) facilities operating in the U.S. performing a variety of services. Most of these facilities store LNG for "peak shaving," where the LNG is vaporized and transported in gas transmission or gas distribution pipelines for periods of peak demand. There is significant growth in the number of facilities producing LNG as a transportation vehicle fuel for trucks, buses, trains, and ships. Depending on the location and use, several Federal agencies and State utility regulatory agencies may regulate an LNG facility.

For LNG import and export facilities located onshore, three Federal agencies share oversight for safety and security: the Federal Energy Regulatory Commission (FERC), the U.S. Coast Guard, and the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA). Under Section 3 of the Natural Gas Act of 1938, FERC is responsible for authorizing the siting and construction of onshore and near-shore LNG import or export facilities. Under Section 7 of the Natural Gas Act of 1938, FERC also issues certificates of public convenience and necessity for LNG facilities engaged in interstate natural gas transportation by pipeline. As required by the National Environmental Policy Act (NEPA), FERC prepares NEPA analyses for proposed LNG facilities under its jurisdiction. The Coast Guard has authority over the safety of LNG vessels and the marine transfer area, conducting Waterway Suitability Assessments to address navigation safety and port security issues associated with LNG ship traffic. PHMSA has authority to establish and enforce safety standards for onshore LNG facilities.

PHMSA's regulations for LNG facilities appear in Title 49, Part 193 of the Code of Federal Regulations (CFR). LNG facility applicants, when applying to FERC, are required to identify how their proposed facility would meet the siting requirements of 49 CFR Part 193. FERC consults with its cooperating agencies, including PHMSA, as needed. Once FERC approves a project and the applicant moves forward in the process, PHMSA inspects sites during and after construction, and during facility operation, and is responsible for taking enforcement action under Part 193 if necessary.

G3. As an operator, how do I submit an application to install a FERC regulated LNG facility?

The FERC is responsible for authorizing the siting and construction of onshore and near-shore LNG import or export facilities and LNG facilities engaged in interstate natural gas transportation by pipeline. As an operator of one of these types of facilities, you must coordinate with the FERC in the development of the Resource Reports required for the FERC application process. Information on Resource Reports 11 & 13, which deals with the engineering detail of the LNG facility, can be found in 18 CFR 380.12 (m) & (o).

G4. What types of LNG facilities require information submittal?

If an LNG facility requires FERC review and siting approval, PHMSA as a cooperating agency will require detailed information as described in these FAQs. Please refer to Subpart A of Part 193 for scope and applicability of PHMSA's regulations. There are regulations in Part 193 pertaining to siting, design, construction, equipment, maintenance, personnel qualifications and training, fire protection, and security. If the operator has questions or needs further guidance on the applicability of Part 193 to the facility in question, then the operator may contact PHMSA headquarters or the PHMSA Regional Offices. PHMSA's regional contact information is located here, or you may contact PHMSA's Director of Engineering as noted below under FAQ #G6.

G5. Does PHMSA have an application or permitting process for new or modified LNG facilities that are subject to the jurisdiction of Part 193 but does not require FERC review?

PHMSA does not require an application process and does not have authority for permitting LNG facilities. PHMSA requires LNG operators submit information to the National Registry of Pipeline and LNG Operators database 60 days prior to commencing construction. See FAQ #G10 below for more information.

LNG operators may be required to submit an application to the Federal Energy Regulatory Commission (FERC) or the appropriate state agency. Operators must notify the State Pipeline Safety Agencies at least 2 weeks prior to the installation of portable LNG facilities and provide information prescribed in §193.2019 (b).

Determining how to comply with 49 CFR 193 is the responsibility of the operator. PHMSA is available to answer your questions. Please contact Ken Lee, Director, Engineering and Research Division (202) 366-2694 or by email kenneth.lee@dot.gov.

G6. Since PHMSA is a cooperating agency in the FERC siting process, do I need to provide anything directly to PHMSA in order to help expedite the application process?

Yes. If a facility is subject to Part 193 (see reply to FAQ #G3 above), then in order for PHMSA to perform an in-depth review and analysis, you should copy and forward specific items for evaluation. You should send all application materials directly to FERC, but you should also submit to PHMSA hard and digital copies of the documents noted in these FAQs to aid PHMSA in its review. Review of your application will be delayed unless you promptly submit to PHMSA substantially complete application materials. Please also be aware that PHMSA will need detailed materials without any redaction, regardless of security sensitive or proprietary information, in order to conduct a full review. If you believe your materials are security sensitive or proprietary in any way, please mark them accordingly.

Materials noted below should be addressed to:

U.S. Department of Transportation
Pipeline & Hazardous Materials Safety Administration
Kenneth Lee – Director
Engineering and Research Division
East Building, Room E22-334
1200 New Jersey Avenue, SE
Washington, DC 20590
Telephone: (202) 366-2694
Email: kenneth.lee@dot.gov

G7. What specific items should be sent to PHMSA?

The applicant should submit a Design Spill Package directly to PHMSA to aid in the review process. Detailed engineering materials are required as part of the Design Spill Package.

The Design Spill Package should include:

a. Project description, background, purpose and details describing the proposed facility;
b. Hazard reports, including any attachments and referenced reports;
c. Facility location map(s), topography map(s), and site aerial photography;

d. Engineering drawings including an overall plot plan showing the project's property boundary and unit plot plans for each process area or system showing the location and elevation of major equipment. Each area and piece of equipment should be clearly labeled. The unit plot plans should be detailed enough to allow for measurement of distances between various components with a reasonable degree of accuracy. The smallest scale submitted should be no smaller than 1-inch to 100-feet (1:1200);
e. Piping and instrument drawings (P&ID);
f. Process Flow Diagrams (PFD);
g. Heat and Material Balance Sheets (H&MB);
h. Piping Inventory Table;
i. Pump and compressor curves for pumps and compressors used for hazardous fluid service (as available);
j. Sketch on plot plan showing expected locations and elevations of major potential single accidental leakage sources;
k. Dimensions, capacities, and thermal properties for any impoundments associated with this project;
l. Design details for mitigation measures, including vapor barriers and pipe-in-pipe systems; and
m. The summary report of all input and output parameters for computer program simulations (i.e., PHAST) should be included.
   Note: The summary report will provide the design spill criteria and screening assessment that was used.

If additional information is required, PHMSA will work with the applicant on additional information submittals.

G8. After I submit information to PHMSA, how long will the review process take?

The duration of the review process varies. There are a variety of factors which influence the timeline for review and approval, including the volume of previously submitted applications, where the applicant is in the siting process, and the completeness of the submitted information. PHMSA will acknowledge receipt of the application and will begin the review process. PHMSA will contact the applicant during the review process to resolve any outstanding needs or questions.

G9. After I submit the required information to PHMSA, what information do I need to file on the FERC docket?

For those projects under FERC jurisdiction, all information submitted to PHMSA should be filed on the FERC docket. PHMSA will work with the applicant to review the information. If revisions or edits are necessary, the applicant will be instructed to file an addendum to the FERC docket.

G10. A FERC regulation (18 CFR § 385.2201) prohibits off-the-record communications in a contested, on-the-record proceeding. The rule is designed to limit communications between a "decisional employee" at FERC and persons outside the Commission. How do FERC's restrictions on ex parte communication affect PHMSA's communications with LNG project applicants?

The purpose of the rule is to ensure the integrity and fairness of the Commission's decisional process, and to prevent off-the-record communications relative to the merits of a Commission proceeding between FERC decisional employees and entities outside of the Commission. Generally, communications regarding Part 193 compliance between PHMSA and a party before the Commission do not violate FERC's ex parte rules. However, PHMSA takes care to not act as a conduit for otherwise unpermitted communications. Some communication between PHMSA and a facility applicant is expected, but PHMSA restricts those communications to matters that FERC has explicitly referred to PHMSA. In accordance with the FERC's public disclosure requirements and FERC's responsibilities under its ex parte regulations, PHMSA, as a cooperating agency, cannot release pre decisional information related to the NEPA analysis (such as working drafts of NEPA documents and PHMSA comments on those working drafts).

If PHMSA needs additional information from an applicant to resolve a matter that FERC has referred to us, PHMSA will advise FERC and the applicant of what additional information is needed and request that it be submitted to FERC's docket.

G11. How do operators notify PHMSA that construction, upgrade, or refurbishment of an LNG facility will be commencing?

New operators must first obtain an Operator Identification Number (OPID). To obtain on OPID, an operator must complete an OPID Assignment Request DOT Form PHMSA F 1000.1 through the National Registry of Pipeline and LNG Operators in accordance with §191.22(a).

Each operator of an LNG plant or LNG facility is required to submit notification of specified events to PHMSA in accordance with §191.22(c). Operators must use the Operator Registry Notification (Form PHMSA F 1000.2) to report new construction, asset-changing or program-changing events associated with LNG facilities. Within Form PHMSA F 1000.2, operators planning to begin new construction, refurbishment or an upgrade project, regardless of cost, select a Type J – New Construction Notification.

Construction notifications are required to be submitted 60 days prior to the "event." On September 12, 2014, PHMSA published an Advisory Bulletin describing the activities that constitute the "event" of construction, which determines the due date for the notification. The types of construction events that would initiate a notification submittal include material purchasing and manufacturing, right-of-way acquisition, construction equipment move-in activities, onsite or offsite fabrications, or right-of-way clearing, grading and ditching.

Click here to view LNG Construction Report – Notification Type J in a new window.

Note that operators have requirements for the reporting of incidents, safety-related conditions, and annual pipeline summary data in accordance with §191.1 and to submit mapping data to the National Pipeline Mapping System (NPMS) in accordance with §191.7. Requests for OPID, construction notifications, and reporting must be made online via the PHMSA portal, using assigned user name and password, unless an alternate method is approved. Copies of the forms and instructions for PHMSA F 7100.3 (Incident Report) and PHMSA F 7100.3-1 (Annual Report) can be found on the Pipeline Safety Community Web Page at https://www.phmsa.dot.gov/forms/pipeline-forms. Contact the PHMSA Information Resources Manager at (202) 366-8075 if you have questions. For information about making an NPMS submission, see https://www.npms.phmsa.dot.gov/PipelineOperator.aspx.

G12. What are the siting requirements for small LNG facilities that have an aggregate storage capacity of 70,000 gallons or less on one site?

The writer asks, "Part 193 has requirements for thermal radiation exclusion and vapor-gas dispersion exclusion zones that are required for *each* LNG container and transfer system, but NFPA 59A, 2001 edition has Table 2.2.4.1 *Distances from Impoundment Areas to Buildings and Property Lines* for small LNG facilities with total onsite storage capacity of 70,000 gallons LNG or less. Does NFPA 59A, 2001 edition, Chapter 2, Plant Siting and Layout, paragraph 2.2.3.7 which allows use of Table 2.2.4.1 'Distances from Impoundment Areas to Buildings and Property Lines' *conflict* with Part 193 Subpart B – Siting Requirements?"

Part 193 siting requirements include the determination of exclusion zones, areas in which the operator or a government agency legally controls all activities. The exclusion zones are determined by complying with §193.2057 *Thermal radiation protection* and §193.2059 *Flammable vapor-gas dispersion protection*. These sections incorporate by reference NFPA 59A paragraph 2.2.3.2 (thermal radiation distance) and paragraphs 2.2.3.3 and 2.2.3.4 (vapor dispersion distance). NFPA 59A paragraph 2.2.3.7 is not provided as an alternative to §193.2057 and §193.2059 for permanent facilities.

Under §193.2019, mobile and temporary LNG facilities need not meet the requirements of Part 193 (including sections 193.2057 and 193.2059) if they comply with the applicable sections of NFPA 59A that is incorporated by reference. NFPA 59A paragraph 2.3.4 covers the requirements for such facilities. 2.3.4(g) references Table 2.2.4.1 for the spacing guidelines at mobile and temporary facilities. When table 2.2.4.1 is used for compliance with paragraph 2.3.4 (g), the aggregate capacity of the multiple LNG containers on the temporary site is to be used to determine facility spacing.

(D) Design

D1. What wind speed should be used in LNG facility equipment design calculations?

Wind forces are addressed in 49 CFR § 193.2067, which requires that LNG facilities be designed to withstand the direct effect of wind forces without loss of structural or functional integrity. Structural engineering design is typically performed using 3-second gust wind speeds in miles-per-hour (mph).

For shop fabricated containers of LNG or other hazardous fluids with a capacity of not more than 70,000 gallons, the wind forces at the location of the specific facility must be based on applicable wind load data in ASCE/SEI 7-05.

For all other LNG facilities, the wind forces at the location of the specific facility must be based on one of the following:

a. an assumed sustained wind velocity of not less than 150 MPH; or
b. a sustained wind velocity of less than 150 MPH that is justified by adequate supportive data and found acceptable by the Administrator; or
c. the most critical combination of wind velocity and duration, with respect to the effect on the structure, having a probability of exceedance in a 50-year period of 0.5 percent or less, if adequate wind data are available and the probabilistic methodology is reliable.

For most structural engineering design calculations, the sustained wind velocity is converted to 3-second gust wind speed using a conservative method based on sound engineering principles. The Durst curve is an acceptable conversion method in ASCE/SEI 7-05, Chapter C6. Using this method, a sustained wind velocity of 150 mph is equivalent to a 183 mph 3-second gust. Applicants should also design all facilities to meet all applicable local or state building codes.

D2. To what parts of the facility does § 193.2067(b)(2) apply?

This paragraph applies to all LNG facilities other than those that are described in §193.2067(b)(1). The term "LNG facility" is defined in 49 CFR §193.2007. The parts of the LNG plant considered for compliance with this design requirement include all parts used when liquefying natural gas or transferring, storing, or vaporizing liquefied natural gas. This includes piping and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation.

D3. Should the wind speed design criteria of 193.2067 be applied to vapor barriers at the LNG plant?

Since vapor barriers are installed for the purpose of reducing the extent of exclusion zones, they are a part of the LNG facilities and subject to the regulatory wind speed requirements. Vapor barriers must be functional while the LNG facility is in operation.

D4. Can vacuum jacketed piping be used in an LNG plant and may the outer pipe be used for LNG impoundment?

The applicant must fully document any application of vacuum jacketed pipe (VJP) or vacuum insulated pipe (VIP). The design details of the piping as well as the locations where it is to be used must be provided. In cases where the VJP or VIP may affect the prescribed design spills, impoundment determinations, or other hazard calculations, the applicant must fully justify the position and approach being taken. PHMSA will review these applications on a case-by-case basis, and a special permit (see 49 CFR Section 190.341) may be required.

D5. As an operator of a LNG Facility, our pressure vessels will be designed and fabricated to the current American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (BPVC). This differs from the requirements of 49 C.F.R. Part 193. How can I ensure our pressure vessels comply with Part 193?

To comply with the requirements of 49 C.F.R. Part 193, each applicant for a LNG facility designed after March 10, 2004, must do one of the following:

- Ensure compliance with NFPA 59A-2001, Paragraph 3.4.2, using the 1992 ASME BPVC; or,
- Submit an application for a special permit in accordance with 49 C.F.R. § 190.341; or,
- Demonstrate an equivalent level of safety as described in NFPA 59A-2001, Section 1.2.

Any deviation from the above requirements for pressure vessels by an operator of a LNG facility will require submittal of technical documentation for review by PHMSA on a case-by-case basis.

D6. As a design engineering firm or as an operator of a LNG facility, if our pressure vessels are designed and fabricated to the current American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (BPVC), which methods may I use to demonstrate safety equivalency as described in NFPA 59A-2001, Section 1.2, and as mentioned in FAQ D5?

Refer to NFPA 59A (2001), Section 1.2 Equivalency, which states:

Nothing in this standard is intended to prevent the use of systems, methods, or devices of equivalent or superior quality, strength, fire resistance, effectiveness, durability, and safety over those prescribed by this standard. Technical documentation shall be submitted to the authority having jurisdiction to demonstrate equivalency. The system, method, or device shall be approved for the intended purpose by the authority having jurisdiction.

When pressure vessels are designed and fabricated for use under Part 193 by using a more recent edition of the ASME BPVC than the 1992 version, the Operator is responsible to document the method used to determine equivalency and make this technical documentation available to PHMSA upon request. PHMSA will accept one of the following methods to demonstrate equivalency in accordance with NFPA 59A-2001, Section 1.2:

- Pressure vessels may be designed and fabricated to meet the requirements for test pressure and design margin factors found in the 1992 edition of the ASME BPVC; or,
- The maximum allowable working pressure (MAWP) for the pressure vessels may be reduced by the amount that results in a test pressure for all pressure vessels meeting the requirements in the 1992 edition of the ASME BPVC Section VIII, Division 1 or Division 2; or,
- Longitudinal, circumferential, nozzle-to-shell, tube sheet, header box, and nozzle-to-box header welds may be inspected by nondestructive examination (NDE). All longitudinal and circumferential welds and nozzle-to-shell welds for process nozzles six (6) inches or larger in diameter must be subject to 100% NDE. Accepted NDE methods are radiograph testing (RT), ultrasonic testing (UT), magnetic particle testing (MPT or MT), and dye penetrant testing (DPT or PT) along the entire weld length in accordance with the applicable sections of the current ASME Section VIII or other applicable standards. Longitudinal and circumferential welds must be subject to radiographic or ultrasonic testing; or,
- The operator of the LNG facility may develop, document, and implement a systematic approach, with annual inspections not to exceed 15-months, to ensure the long-term integrity of all its pressure vessels and pressure-relieving devices protecting these vessels within the LNG facility. The asset-management procedure must incorporate and comply with a current recognized and generally accepted American National Standards Institute (ANSI) standard such as the American Petroleum Institute (API) 510, "Pressure Vessel Inspection Code: In-service Inspection, Rating, Repair, and Alteration," 10th Edition. The procedures must be adopted into the operator's operations and maintenance (O&M) manual. The procedures must be updated, as needed, for the continuous, effective management of pressure vessel integrity that must include over pressure protection, corrosion, pipe wall thickness loss, cracking on both girth and longitudinal welds and steel body, loading stresses such as loads on nozzles from piping, valves, other components, and soil settlement and environmental deterioration of the pressure vessel due to weathering. Adoption and implementation of a pressure vessel asset management plan is in addition to the existing minimum requirements for operations, maintenance, and personnel qualifications and training found in 49 CFR Part 193 and NFPA 59A-2001. The operator must maintain all records and procedures for design, construction, testing, repairs, and O&M activities as required in API 510. The "Risk Based Inspection" option in Section 6.3 of API 510 is not an acceptable O&M inspection and evaluation method; or,
- The operator may submit to PHMSA another system, method, or device that is intended to demonstrate equivalency for evaluation and review on a case-by-case basis.

(DS) Design Spill Determination

DS1. The criteria and methodology used to identify single accidental leakage sources (SALS) to establish siting for my LNG facility were based on the failure rate table methodology. Do I need to submit a new or revised Design Spill Package to PHMSA based on the current SALS methodology?

No. PHMSA will not require the applicant to submit a new or revised Design Spill Package and will not retroactively apply the current SALS methodology to facilities that have received a previous PHMSA correspondence of no objection to their methodology for determining the SALS for design spills used in establishing the 49 CFR Part 193 siting requirements. If the applicant chooses to modify the design spills that were previously determined to be in compliance with Part 193 siting requirements, PHMSA will require an updated Design Spill Package as described in these FAQs. For those projects under FERC jurisdiction, the applicant will also need to file the updated information submitted to PHMSA on the FERC docket.

DS2. 49 CFR 193 requires that design spills for an LNG plant be selected according to NFPA 59A-2001 Paragraph 2.2.3.5. NFPA 59A requires the evaluation of accidental flow from "any single accidental leakage source" (SALS) but does not define this term. How should I select SALS events in an LNG plant?

For piping and equipment that handle LNG, flammable refrigerants, toxic components, and any other hazardous fluid, leakage sources may be chosen using the following guidelines. The SALS selection methodology, below, is applied to determine the maximum hole sizes of interest for the most significant releases of each hazardous fluid in each portion of the LNG plant. (The SALS selections are one component of design spill definition. Please refer to other FAQs for additional design spill definition topics.)

A. For piping segments, including transfer arms and double-ply construction expansion bellows, that are:
   1. Greater than or equal to 6 inches in diameter, a hole of 2 inches in diameter is applied at any location along the piping segment; and
   2. Less than 6 inches in diameter, a full-bore rupture (guillotine failure) is applied at any location along the piping segment.
B. For single-ply construction expansion bellows, a hole size equivalent to a full-bore rupture of the diameter of the expansion joint is applied;
C. For pipe-in-pipe systems, an unobstructed release from an equivalent 1-inch diameter hole may be applied at the operating conditions of the inner pipe when:
   1. The system complies with NFPA 59A (2016) Section 9.11;
   2. The outer pipe is able to withstand the thermal shock, mechanical forces, and pressure loads of any single accidental leakage source from A and B above applied to the inner pipe; and
   3. Design, fabrication, examination, and testing of the pipe-in-pipe system, including calculations, can be demonstrated.

The selection of any alternate hole size or release scenario definition will be reviewed on a case-by-case basis in lieu of the criteria defined above; and

D. For transfer hoses, a hole size equivalent to a full-bore rupture of the transfer hose is applied.

DS3. PHMSA reviews the design criteria for design spills on a case-by- case basis to determine compliance with Part 193. What information is required to assist PHMSA in its determination of the design spill criteria acceptable for use?

Applicants must provide a piping inventory table of LNG plant components in hazardous or flammable fluid service. At a minimum, the table should include piping of 2 inches in diameter and larger, as well as transfer hoses. The inventory table should be submitted in Excel (*.XL*) format. Separate tabs or lists should be used for each type of hazardous fluid, with demarcation of all of the final design spill selections. The table should include the following information:

a. Line segment scenario number to identify the leakage source scenario;
b. Description of line segment purpose (LNG rundown header, KO Drum drain, relief valve inlet, level gauge instrument connection, etc.);
c. General plant area or service (e.g. liquefaction train, refrigerant storage, marine area, etc.), unless the entire project is confined to one area;
d. Beginning point location (e.g., exchanger outlet flange) for each line;
e. Ending point location (e.g., pump suction nozzle) for each line;
f. Line diameter;

g. Hazardous fluid service (LNG, natural gas, refrigerants (such as propane, ethane, mixed refrigerant), ammonia, natural gas liquids (NGL) or gas condensate, acid gas (containing hydrogen sulfide), etc.);
h. P&ID drawing number reference(s) for each segment;
i. Piping line designation on P&ID
j. Fluid conditions within the line segment (e.g., fluid phase (liquid or vapor); density (lb/ft3); pressure (psig); temperature (°F); mass flow rate, (lb/hr); composition of mixed refrigerants, NGL/condensates, acid gas (mol%));
k. Process flow diagram and corresponding heat and material balance stream number;
l. Heat and material balance case selection;
m. Leakage source hole size;
n. Calculated total release flow rate (lb/hr);
o. Calculated depressurization or equilibrium pressure used for release flow rate (psig);
p. Release duration;
q. For potential design spill selections, include release height, orientation, rainout percentage, total vapor mass flow rate (lb/hr), deinventory duration, and screening dispersion distance (ft); and
r. Comments, including any pump run out percentages used, as well as justifications or other details for the final design spills selected.

DS4. Is the largest size hole always used as the hole size in release modeling?

Not necessarily. For any defined maximum hole size, the applicant must demonstrate that that the hole size selected produces the greatest vapor dispersion distance when accounting for the mechanisms of flashing, jetting, aerosol formation, and rain-out. If a smaller hole size creates a larger vapor dispersion hazard distance, that smaller hole size should be used to define the design spill event. This applies to all single accidental leakage sources, including failures at piping, piping connections, and transfer hoses.

DS5. What are the proper release height and orientation to use for a design spill?

For each design spill identified, the release height should be the one that defines the largest hazard distances, bounded within the actual or anticipated heights of the equipment and piping.

Release orientation should be horizontal for each design spill unless a vertical orientation would produce higher consequences. Vertical orientations that provide higher consequences generally include:

- vertically upward for liquid releases with rainout greater than 25% (e.g., heavy hydrocarbons, pentane, etc.);
- vertically downward for gaseous releases (e.g., acid gas) ; and
- where mitigation measures would control or redirect the release, specific release orientations may be considered (e.g., pipe shrouding that directs a fluid downward, the downward direction may be applied).

A sensitivity analysis should be provided to demonstrate which release orientation scenario (horizontal, vertical upward, or vertical downward, as applicable) results in the largest hazard distance.

DS6. How are release locations defined?

For single-ply expansion joint or transfer hose failures, the release location can be identified at the specific point of that component in the LNG plant. For piping segments, the selected hole can occur at any location along the piping segment. If vapor barriers, shrouds, or pipe-in-pipe designs are used to reduce the vapor dispersion distance, locations potentially not impacted by the vapor barrier, shroud, or pipe-in-pipe should also be selected.

DS7. How do I determine the process conditions to evaluate for hazard modeling?

Process conditions should be based on heat and material balance modes of operation and design case (e.g., rich, lean, average, etc.) that produce the worst case dispersion results from flashing and jetting and liquid releases. The leakage sources from branch connections should be considered using the potential operational conditions along the pipe as well as the potential operational conditions that could be experienced at or near the branch pipe connection to a main process line. In cases that would reduce the back pressure on pump(s) or compressor(s), the flow rates should consider the potential increased pump or compressor flow determined by the pump and compressor curve(s) as detailed in DS10 and also consider the decrease in temperature and pressure during runout conditions.

DS8. What considerations should be given to system inventory and spill duration in the design spill calculations?

The applicant may need to demonstrate the selected design spill duration. The release modeling should account for the available system inventory (including piping, process vessels, storage vessels, and other process equipment) when calculating the design spill duration as follows:

A. Applicants may use a 10-minute spill duration if the process design includes acceptable detection, isolation, and shutdown.
B. For long and large-bore piping with a significant distance between isolation valves (emergency shutdown or manually or remotely operated), as well as releases from process or storage vessels, the dispersion modeling may continue beyond the 10-minute design spill duration to account for the inventory volume in the piping and the entire contents of any vessels at maximum design level(s), unless the dispersion modeling endpoint reaches its furthest extent in a shorter time.
C. A release duration of less than 10 minutes may be used for release scenarios where the available system inventory may be depleted in less than 10 minutes. The applicant may elect this shorter duration based on demonstrable surveillance, shutdown, and isolation design with valve closures from emergency shutdowns or remote valve operation per NFPA 59A-2001. All scenario isolation valves must be protected from failure, including fire and external impacts. The shutdown system must meet a safety integrity level (SIL) 2 or SIL3 reliability design and maintenance requirements in accordance with the International Society of Automation (ISA) 84 standards.

DS9. How should I consider a release from a process or storage vessel in the design spill calculations?

For systems with a process or storage vessel, the applicant should first select the appropriate release scenarios that account for the pipe flow (normal operational or pump run out) from the piping connecting to a vessel, based on FAQs DS7 and DS10. Furthermore, a comparative release scenario should be provided using the process or storage pressure from the vessel. This pressurized release rate may be calculated using the orifice equation at full operational system pressure, including the hydrostatic head from the maximum liquid design level, for the entire design spill duration. This corresponding duration would last until the inventory that could be isolated by valves would be depleted. The applicant should then perform a comparative screening to determine whether the piping or the vessel-pressurized scenario would result in the worst case dispersion distance.

Alternatively, transient flow scenarios may be evaluated to more precisely account for the effects of demonstrable surveillance, shutdown, and de-inventorying of the piping and vessel(s) on the release rate.

A transient flow scenario should account for the most significant leakage source release from piping and the vessel, taking into account the normal flow into the vessel and the pressurized head space in the vessel.

DS10. Do I need to consider pump run-out in release scenario calculations?

Applicants should use pump run-out (greater flow than in normal pump flow operations) in failure calculations if the pump design allows increases in flow as the discharge pressure is reduced, unless acceptable preventive measures are used that prevent the pump from run out conditions. Pump runout parameters are presented by the pump manufacturer as a pump curve that shows flow increasing as the discharge pressure decreases. If pump run-out flows are not known at the time of submittal, engineering estimates may be employed provisionally.

Acceptable preventive measures include pump interlocks or safety instrumented prevention systems that meet safety integrity level (SIL) 2 or SIL3 reliability design and maintenance requirements in accordance with the International Society of Automation (ISA) 84 standards.

DS11. Should multiple pumps be considered when calculating the greatest flow from a spill to size impoundments or when defining a single accidental leakage source event?

Where the greatest flow is potentially fed from multiple pumps, calculate the flow to size impoundments assuming that all pumps are running, unless acceptable preventive measures are used that prevent all pumps from running concurrently.

Where a piping system utilizes multiple pumps, calculate the design spill based on the total flow from all system pumps running, unless acceptable preventive measures are used that prevent or limit all pumps from running concurrently.

Acceptable preventive measures include pump interlocks or safety instrumented prevention systems that meet safety integrity level (SIL) 2 or SIL 3 reliability design and maintenance requirements in accordance with the International Society of Automation (ISA) 84 standards.

(H) Hazards and Hazards Modeling

H1. Other than the flammable vapor dispersion and thermal radiation from hazards associated with LNG, what other hazards should be evaluated in the siting analysis for an LNG plant?

According to NFPA 59A-2001 Paragraph 2.1.1(d), (incorporated by reference in 49 CFR Part 193), all hazards that can affect the safety of the public or plant personnel are to be considered. In addition to LNG, the applicant should consider hazards associated with flammable gases, flammable refrigerants, flammable or combustible liquids, or acutely toxic materials. If present at the LNG plant, hazards including vapor dispersion from liquid pools, vapor dispersion from jetting and flashing phenomena, thermal radiation from pool fires, thermal radiation from fires involving jetting and flashing phenomena (jet fires), overpressure from vapor cloud ignitions, toxic gas dispersion, and boiling liquid expanding vapor explosions (BLEVEs) involving pressurized storage vessels should be included in an LNG plant's hazard evaluation.

H2. My LNG plant includes some toxic materials. What considerations should be given to accidental releases of these materials and the associated hazard modeling?

While the hazards associated with toxic substances at an LNG plant are not prescriptively covered in 49 CFR Part 193, their consideration is required by NFPA 59A-2001 Paragraph 2.1.1(d) (incorporated by reference in 49 CFR Part 193), which requires that all hazards that can affect the safety of the public or plant personnel be considered.

Many toxic substances stored above certain quantities are regulated under Appendix A of the EPA's "Risk Management Program for Chemical Accidental Release Prevention" (RMP, 40 CFR 68) and OSHA's "Process Safety Management of Highly Hazardous Chemicals" (PSM, 29 CFR 1910.119). Compliance with EPA's RMP and OSHA's PSM regulations is a sufficient approach to comply with NFPA 59A Paragraph 2.1.1(d). PHMSA does not have authority to enforce EPA or OSHA regulations, but requires operator compliance with NFPA 59A Paragraph 2.1.1(d).

Consideration of toxic hazards must include dispersion modeling appropriate for the toxic substance and its behavior upon release, as well as incorporating safety measures of the design and operation of the facility. Applicants may propose alternative modeling methods to comply with NFPA 59A Paragraph 2.1.1(d) for toxic substances. The release scenario selection methodology should be consistent with the selection methodology defined in FAQs DS2 and DS4 through DS11. In addition, the dispersion modeling should consider a method to account for the potential combined impacts of toxic components (e.g., the principle used in the Compressed Gas Association P-20 methodology). The AEGL values are the preferred endpoints to be used in the calculations with an exposure duration corresponding to the release event, up to 1 hour. Because there are no specific exclusion zones that are to be defined for toxic materials, the opposite impacts at each proposed LNG plant will be evaluated on a case-by-case basis.

H3. Materials received, stored, or used at my LNG plant could generate overpressures from a vapor cloud explosion. What considerations should be given to vapor cloud explosions and the associated hazard modeling?

While explosion overpressure is not prescriptively covered in 49 CFR Part 193, its consideration is required by NFPA 59A-2001 Paragraph 2.1.1(d) (incorporated by reference in 49 CFR Part 193), which requires that all hazards that can affect the safety of the public or plant personnel be considered. Vapor cloud explosion modeling should involve consideration of vapor dispersion modeling results, evaluation of areas of confinement and congestion, and the potential reactivity of released materials. The use of the 1.0 psi overpressure endpoint is appropriate for explosion modeling, and is consistent with the EPA's "Risk Management Program for Chemical Accidental Release Prevention" (RMP, 40 CFR 68). Because there are no specific exclusion zones that are to be defined for explosion overpressure impacts, the offsite impacts at each proposed LNG plant will be evaluated on a case-by-case basis.

H4. What wind direction should be used in exclusion zone and other hazard calculations?

For most hazard calculations, the exclusion distance or hazard distance is calculated independent of wind direction. If the wind direction is important in the modeling methods used, the direction used should be toward the nearest property line. Additional wind directions may also need to be analyzed if the hazard could extend beyond other property lines or cause other unique hazards.

H5. Can an exclusion zone extend beyond the operator's LNG plant property line?

As long as the facility is in operation, the operator is responsible for assuring compliance with the limitations on land use within exclusion zones, according to the descriptions in NFPA 59A Sections 2.2.3.2, 2.2.3.3, and 2.2.3.4. For example, an exclusion zone that extends past a property line into a navigable body of water or onto a public road is typically acceptable. This may not hold true if that body of water contains a dock or pier that is not controlled by the operator of the LNG plant, or if another entity could erect a building or members of the public could assemble within the exclusion zone. It is possible to assure compliance by legal agreement with a property owner affected by the exclusion zone, such that the land use is restricted for the life of the LNG plant.

H6. In addition to DEGADIS 2.1 and FEM3A, Section 193.2059 Flammable vapor dispersion protection provides for the use of alternate models approved by US DOT PHMSA. What other models have been approved?

US DOT PHMSA has approved two additional models for the determination of vapor dispersion exclusion zones: FLACS 9.1 Release 2 (Oct. 7, 2011) and PHAST-UDM Version 6.6 and 6. 7 (Oct. 7, 2011). Each model has been validated for use in certain conditions in accordance with the Model Evaluation Protocol (MEP) as described in M. J. Ivings et al., Evaluating Vapor Dispersion Models for Safety Analysis of LNG Facilities Research Project: Technical Report (Apr. 2007) (available at http://www.nfpa.org).

For detailed information regarding the conditions for which the models were validated, see PHMSA's final decision at:

FLACS http://www.regulations.gov/#!docketDetail;D=PHMSA-2011-0101

PHAST http://www.regulations.gov/#!docketDetail;D=PHMSA-2011-0075

H7. Does US DOT PHMSA prescribe source term models for flammable vapor dispersion modeling?

While PHMSA does not prescribe or approve source term models, the source term model must have a creditable scientific basis and must not ignore any phenomena that can influence vapor formation during discharge from containment, conveyance to an impoundment, and retention within the impoundment. In July, 2010 PHMSA communicated in interpretation PI-10-0021 that the SOURCE5 model does not satisfy the PHMSA requirements for a source term model. The interpretation can be viewed at:

https://www.phmsa.dot.gov/regulations/title49/interp/PI-10-0021.

H8. Can mitigation measures be used in exclusion zone and other hazard calculations?

For most hazard calculations, passive mitigation measures are inherently acceptable, provided that their design and implementation can be technically supported and that they do not introduce other harmful consequences.

Active or procedural mitigation measures are generally not included exclusion zone or hazard zone calculations. However, PHMSA will review the proposed inclusion of such measures on a case-by-case basis, provided that proper supporting technical justification and documentation is submitted.

Updated: 7/25/2018

Frequently Asked Questions

https://www.phmsa.dot.gov/pipeline/liquified-natural-gas/phmsa-lng-frequently-asked-questions-archive-records

June 21, 2023

G) General

G1. The abundant supply of domestic natural gas is driving development of new ways to use, process, and transport LNG. Can PHMSA provide guidance as to which LNG facilities are regulated under 49 CFR Part 193?

The Pipeline Safety Statute codified in 49 U.S. Code § 60101, et seq, directs US DOT to establish and enforce standards for liquefied natural gas pipeline facilities. An LNG facility is a gas pipeline facility used for converting, transporting or storing liquefied natural gas.

Many LNG facilities are subject to the regulatory and enforcement authority of the Department of Transportation through PHMSA. A simple but not complete test to determine if an LNG facility is regulated under 49 CFR Part 193 is to identify both the source and the consumer of the LNG. The facility is regulated under 49 CFR Part 193 if the LNG facility either receives from or delivers to a 49 CFR Part 192 pipeline.

49 CFR Part 193 does not apply to:

1. LNG facilities used by ultimate consumers of LNG or natural gas.
2. LNG facilities used in the course of natural gas treatment or hydrocarbon extraction that do not store LNG.
3. In marine cargo transfer systems and associated facilities, any matter other than siting pertaining to the system or facilities between the marine vessel and the last manifold (or, in the absence of a manifold, the last valve) located immediately before a storage tank.
4. Any LNG facility located in navigable waters (as defined in Section 3(8) of the Federal Power Act (16 U.S.C. 796(8)).

Operators should assume an LNG facility used in the transportation of gas by a 49 CFR Part 192 pipeline is regulated under 49 CFR Part 193 unless specifically exempted in Section 193.2001(b). LNG facilities may be regulated by PHMSA even though they are not regulated by the FERC. The ‘ultimate consumer' provision provides a very limited exemption from 49 CFR Part 193. PHMSA interpretation # PI-10-0025 provides guidance. Here is an excerpt:

> *During the rulemaking that led to the adoption of § 193.2001(b)(1), OPS explained that the intent of that provision was to create an exception for "an LNG facility used by the ultimate consumer of the product". Likewise, in responding to a series of questions from a congressional committee, OPS stated that the exception in § 193.2001(b)(1), was*

designed for "small" facilities which are "generally located in industrial plants ... [to] serve as a supply of energy or feedstock for the plant." Unlike these examples, the Maine LMF facilities would be used to produce LNG for sale and distribution by truck, not solely for onsite consumption. Therefore, OPS concludes that your client's facilities would not qualify for the end-user exception in § 193.2001(b)(1).

Follow this link for a map of LNG Plants regulated under 49 CFR Part 193 (except mobile and temporary). This document illustrates examples of LNG facilities that are or are not regulated under 49 CFR Part193.

G2. What agency or agencies have regulatory authority over the siting of LNG facilities?

There are more than 110 liquefied natural gas (LNG) facilities operating in the U.S. performing a variety of services. Most of these facilities store LNG for "peak shaving," where the LNG is vaporized and transported in gas transmission or gas distribution pipelines for periods of peak demand. There is significant growth in the number of facilities producing LNG as a transportation vehicle fuel for trucks, buses, trains, and ships. Depending on the location and use, several Federal agencies and State utility regulatory agencies may regulate an LNG facility.

For LNG import and export facilities located onshore, three Federal agencies share oversight for safety and security: the Federal Energy Regulatory Commission (FERC), the U.S. Coast Guard, and the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA). Under Section 3 of the Natural Gas Act of 1938, FERC is responsible for authorizing the siting and construction of onshore and near-shore LNG import or export facilities. Under Section 7 of the Natural Gas Act of 1938, FERC also issues certificates of public convenience and necessity for LNG facilities engaged in interstate natural gas transportation by pipeline. As required by the National Environmental Policy Act (NEPA), FERC prepares NEPA analyses for proposed LNG facilities under its jurisdiction. The Coast Guard has authority over the safety of LNG vessels and the marine transfer area, conducting Waterway Suitability Assessments to address navigation safety and port security issues associated with LNG ship traffic. PHMSA has authority to establish and enforce safety standards for onshore LNG facilities.

PHMSA's regulations for LNG facilities appear in Title 49, Part 193 of the Code of Federal Regulations (CFR). LNG facility applicants, when applying to FERC, are required to identify how their proposed facility would meet the siting requirements of 49 CFR Part 193. FERC consults with its cooperating agencies, including PHMSA, as needed. Once FERC approves a project and the applicant moves forward in the process, PHMSA inspects sites during and after construction, and during facility operation, and is responsible for taking enforcement action under Part 193 if necessary.

G3. As an operator, how do I submit an application to install a FERC regulated LNG facility?

The FERC is responsible for authorizing the siting and construction of onshore and near-shore LNG import or export facilities and LNG facilities engaged in interstate natural gas transportation by pipeline. As an operator of one of these types of facilities, you must coordinate with the FERC in the development of the Resource Reports required for the FERC application process. Information on Resource Reports 11 & 13, which deals with the engineering detail of the LNG facility, can be found in 18 CFR 380.12 (m) & (o).

G4. What types of LNG facilities require information submittal?

If an LNG facility requires FERC review and siting approval, PHMSA as a cooperating agency will require detailed information as described in these FAQs. Please refer to Subpart A of Part 193 for scope and applicability of PHMSA's regulations. There are regulations in Part 193 pertaining to siting, design, construction, equipment, maintenance, personnel qualifications and training, fire protection, and security. If the operator has questions or needs further guidance on the applicability of Part 193 to the facility in question, then the operator may contact PHMSA headquarters or the PHMSA Regional Offices. PHMSA's regional contact information is located here, or you may contact PHMSA's Director of Engineering as noted below under FAQ #G6.

G5. Does PHMSA have an application or permitting process for new or modified LNG facilities that are subject to the jurisdiction of Part 193 but does not require FERC review?

PHMSA does not require an application process and does not have authority for permitting LNG facilities. PHMSA requires LNG operators submit information to the National Registry of Pipeline and LNG Operators database 60 days prior to commencing construction. See FAQ #G10 below for more information.

LNG operators may be required to submit an application to the Federal Energy Regulatory Commission (FERC) or the appropriate state agency. Operators must notify the State Pipeline Safety Agencies at least 2 weeks prior to the installation of portable LNG facilities and provide information prescribed in §193.2019 (b).

Determining how to comply with 49 CFR 193 is the responsibility of the operator. PHMSA is available to answer your questions. Please contact Ken Lee, Director, Engineering and Research Division (202) 366-2694 or by email kenneth.lee@dot.gov.

G6. Since PHMSA is a cooperating agency in the FERC siting process, do I need to provide anything directly to PHMSA in order to help expedite the application process?

Yes. If a facility is subject to Part 193 (see reply to FAQ #G3 above), then in order for PHMSA to perform an in-depth review and analysis, you should copy and forward specific items for evaluation. You should send all application materials directly to FERC, but you should also submit to PHMSA hard and digital copies of the documents noted in these FAQs to aid PHMSA in its review. Review of your application will be delayed unless you promptly submit to PHMSA substantially complete application materials. Please also be aware that PHMSA will need detailed materials without any redaction, regardless of security sensitive or proprietary information, in order to conduct a full review. If you believe your materials are security sensitive or proprietary in any way, please mark them accordingly.

Materials noted below should be addressed to:

U.S. Department of Transportation
Pipeline & Hazardous Materials Safety Administration
Kenneth Lee – Director
Engineering and Research Division
East Building, Room E22-334
1200 New Jersey Avenue, SE
Washington, DC 20590
Telephone: (202) 366-2694
Email: kenneth.lee@dot.gov

G7. What specific items should be sent to PHMSA?

The applicant should submit a Design Spill Package directly to PHMSA to aid in the review process. Detailed engineering materials are required as part of the Design Spill Package.

The Design Spill Package should include:

a. Project description, background, purpose and details describing the proposed facility;
b. Hazard reports, including any attachments and referenced reports;
c. Facility location map(s), topography map(s), and site aerial photography;
d. Engineering drawings including an overall plot plan showing the project's property boundary and unit plot plans for each process area or system showing the location and elevation of major equipment. Each area and piece of equipment should be clearly labeled. The unit plot plans should be detailed enough to allow for measurement of distances between various components with a reasonable degree of accuracy. The smallest scale submitted should be no smaller than 1-inch to 100-feet (1:1200);
e. Piping and instrument drawings (P&ID);
f. Process Flow Diagrams (PFD);
g. Heat and Material Balance Sheets (H&MB);
h. Piping Inventory Table;
i. Pump and compressor curves for pumps and compressors used for hazardous fluid service (as available);
j. Sketch on plot plan showing expected locations and elevations of major potential single accidental leakage sources;
k. Dimensions, capacities, and thermal properties for any impoundments associated with this project;
l. Design details for mitigation measures, including vapor barriers and pipe-in-pipe systems; and
m. The summary report of all input and output parameters for computer program simulations (i.e., PHAST) should be included.

n. Note: The summary report will provide the design spill criteria and screening assessment that was used.

If additional information is required, PHMSA will work with the applicant on additional information submittals.

G8. After I submit information to PHMSA, how long will the review process take?

The duration of the review process varies. There are a variety of factors which influence the timeline for review and approval, including the volume of previously submitted applications, where the applicant is in the siting process, and the completeness of the submitted information. PHMSA will acknowledge receipt of the application and will begin the review process. PHMSA will contact the applicant during the review process to resolve any outstanding needs or questions.

G9. After I submit the required information to PHMSA, what information do I need to file on the FERC docket?

For those projects under FERC jurisdiction, all information submitted to PHMSA should be filed on the FERC docket. PHMSA will work with the applicant to review the information. If revisions or edits are necessary, the applicant will be instructed to file an addendum to the FERC docket.

G10. A FERC regulation (18 CFR § 385.2201) prohibits off-the-record communications in a contested, on-the-record proceeding. The rule is designed to limit communications between a "decisional employee" at FERC and persons outside the Commission. How do FERC's restrictions on ex parte communication affect PHMSA's communications with LNG project applicants?

The purpose of the rule is to ensure the integrity and fairness of the Commission's decisional process, and to prevent off-the-record communications relative to the merits of a Commission proceeding between FERC decisional employees and entities outside of the Commission. Generally, communications regarding Part 193 compliance between PHMSA and a party before the Commission do not violate FERC's ex parte rules. However, PHMSA takes care to not act as a conduit for otherwise unpermitted communications. Some communication between PHMSA and a facility applicant is expected, but PHMSA restricts those communications to matters that FERC has explicitly referred to PHMSA. In accordance with the FERC's public disclosure requirements and FERC's responsibilities under its ex parte regulations, PHMSA, as a cooperating agency, cannot release pre decisional information related to the NEPA analysis (such as working drafts of NEPA documents and PHMSA comments on those working drafts).

If PHMSA needs additional information from an applicant to resolve a matter that FERC has referred to us, PHMSA will advise FERC and the applicant of what additional information is needed and request that it be submitted to FERC's docket.

G11. How do operators notify PHMSA that construction, upgrade, or refurbishment of an LNG facility will be commencing?

New operators must first obtain an Operator Identification Number (OPID). To obtain on OPID,

an operator must complete an OPID Assignment Request DOT Form PHMSA F 1000.1 th rough the National Registry of Pipeline and LNG Operators in accordance with §191.22(a).

Each operator of an LNG plant or LNG facility is required to submit notification of specified events to PHMSA in accordance with §191.22(c). Operators must use the Operator Registry Notification (Form PHMSA F 1000.2) to report new construction, asset-changing or program-changing events associated with LNG facilities. Within Form PHMSA F 1000.2, operators planning to begin new construction, refurbishment or an upgrade project, regardless of cost, select a Type J – New Construction Notification.

Construction notifications are required to be submitted 60 days prior to the "event." On September 12, 2014, PHMSA published an Advisory Bulletin describing the activities that constitute the "event" of construction, which determines the due date for the notification. The types of construction events that would initiate a notification submittal include material purchasing and manufacturing, right-of-way acquisition, construction equipment move-in activities, onsite or offsite fabrications, or right-of-way clearing, grading and ditching.

Click here to view LNG Construction Report – Notification Type J in a new window.

Note that operators have requirements for the reporting of incidents, safety-related conditions, and annual pipeline summary data in accordance with §191.1 and to submit mapping data to the National Pipeline Mapping System (NPMS) in accordance with §191.7. Requests for OPID, construction notifications, and reporting must be made online via the PHMSA portal, using assigned user name and password, unless an alternate method is approved. Copies of the forms and instructions for PHMSA F 7100.3 (Incident Report) and PHMSA F 7100.3-1 (Annual Report) can be found on the Pipeline Safety Community Web Page at https://www.phmsa.dot.gov/forms/pipeline-forms. Contact the PHMSA Information Resources Manager at (202) 366-8075 if you have questions. For information about making an NPMS submission, see https://www.npms.phmsa.dot.gov/PipelineOperator.aspx.

G12.What are the siting requirements for small LNG facilities that have an aggregate storage capacity of 70,000 gallons or less on one site?

The writer asks, "Part 193 has requirements for thermal radiation exclusion and vapor-gas dispersion exclusion zones that are required for *each* LNG container and transfer system, but NFPA 59A, 2001 edition has Table 2.2.4.1 *Distances from Impoundment Areas to Buildings and Property Lines* for small LNG facilities with total onsite storage capacity of 70,000 gallons LNG or less. Does NFPA 59A, 2001 edition, Chapter 2, Plant Siting and Layout, paragraph 2.2.3.7 which allows use of Table 2.2.4.1 'Distances from Impoundment Areas to Buildings and Property Lines' *conflict* with Part 193 Subpart B – Siting Requirements?"

Part 193 siting requirements include the determination of exclusion zones, areas in which the operator or a government agency legally controls all activities. The exclusion zones are determined by complying with §193.2057 *Thermal radiation protection* and §193.2059 *Flammable vapor-gas dispersion protection*. These sections incorporate by reference NFPA 59A paragraph 2.2.3.2 (thermal radiation distance) and paragraphs 2.2.3.3 and 2.2.3.4 (vapor dispersion distance). NFPA 59A paragraph 2.2.3.7 is not provided as an alternative to §193.2057 and §193.2059 for permanent facilities.

Under §193.2019, mobile and temporary LNG facilities need not meet the requirements of Part 193 (including sections 193.2057 and 193.2059) if they comply with the applicable sections of NFPA 59A that is incorporated by reference. NFPA 59A paragraph 2.3.4 covers the requirements for such facilities. 2.3.4(g) references Table 2.2.4.1 for the spacing guidelines at mobile and temporary facilities. When table 2.2.4.1 is used for compliance with paragraph 2.3.4 (g), the aggregate capacity of the multiple LNG containers on the temporary site is to be used to determine facility spacing.

(D) Design

D1. What wind speed should be used in LNG facility equipment design calculations?

Wind forces are addressed in 49 CFR § 193.2067, which requires that LNG facilities be designed to withstand the direct effect of wind forces without loss of structural or functional integrity. Structural engineering design is typically performed using 3-second gust wind speeds in miles-per-hour (mph).

For shop fabricated containers of LNG or other hazardous fluids with a capacity of not more than 70,000 gallons, the wind forces at the location of the specific facility must be based on applicable wind load data in ASCE/SEI 7-05.

For all other LNG facilities, the wind forces at the location of the specific facility must be based on one of the following:

a. an assumed sustained wind velocity of not less than 150 MPH; or
b. a sustained wind velocity of less than 150 MPH that is justified by adequate supportive data and found acceptable by the Administrator; or
c. the most critical combination of wind velocity and duration, with respect to the effect on the structure, having a probability of exceedance in a 50-year period of 0.5 percent or less, if adequate wind data are available and the probabilistic methodology is reliable.

For most structural engineering design calculations, the sustained wind velocity is converted to 3-second gust wind speed using a conservative method based on sound engineering principles. The Durst curve is an acceptable conversion method in ASCE/SEI 7-05, Chapter C6. Using this method, a sustained wind velocity of 150 mph is equivalent to a 183 mph 3-second gust. Applicants should also design all facilities to meet all applicable local or state building codes.

D2. To what parts of the facility does § 193.2067(b)(2) apply?

This paragraph applies to all LNG facilities other than those that are described in §193.2067(b)(1). The term "LNG facility" is defined in 49 CFR §193.2007. The parts of the LNG plant considered for compliance with this design requirement include all parts used when liquefying natural gas or transferring, storing, or vaporizing liquefied natural gas. This includes piping and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation.

D3. Should the wind speed design criteria of 193.2067 be applied to vapor barriers at the LNG plant?

Since vapor barriers are installed for the purpose of reducing the extent of exclusion zones, they are a part of the LNG facilities and subject to the regulatory wind speed requirements. Vapor barriers must be functional while the LNG facility is in operation.

D4. Can vacuum jacketed piping be used in an LNG plant and may the outer pipe be used for LNG impoundment?

The applicant must fully document any application of vacuum jacketed pipe (VJP) or vacuum insulated pipe (VIP). The design details of the piping as well as the locations where it is to be used must be provided. In cases where the VJP or VIP may affect the prescribed design spills, impoundment determinations, or other hazard calculations, the applicant must fully justify the position and approach being taken. PHMSA will review these applications on a case-by-case basis, and a special permit (see 49 CFR Section 190.341) may be required.

D5. As an operator of a LNG Facility, our pressure vessels will be designed and fabricated to the current American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (BPVC). This differs from the requirements of 49 C.F.R. Part 193. How can I ensure our pressure vessels comply with Part 193?

To comply with the requirements of 49 C.F.R. Part 193, each applicant for a LNG facility designed after March 10, 2004, must do one of the following:

- Ensure compliance with NFPA 59A-2001, Paragraph 3.4.2, using the 1992 ASME BPVC; or,
- Submit an application for a special permit in accordance with 49 C.F.R. § 190.341; or,
- Demonstrate an equivalent level of safety as described in NFPA 59A-2001, Section 1.2.

Any deviation from the above requirements for pressure vessels by an operator of a LNG facility will require submittal of technical documentation for review by PHMSA on a case-by-case basis.

D6. As a design engineering firm or as an operator of a LNG facility, if our pressure vessels are designed and fabricated to the current American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (BPVC), which methods may I use to demonstrate safety equivalency as described in NFPA 59A-2001, Section 1.2, and as

mentioned in FAQ D5?

Refer to NFPA 59A (2001), Section 1.2 Equivalency, which states:

Nothing in this standard is intended to prevent the use of systems, methods, or devices of equivalent or superior quality, strength, fire resistance, effectiveness, durability, and safety over those prescribed by this standard. Technical documentation shall be submitted to the authority having jurisdiction to demonstrate equivalency. The system, method, or device shall be approved for the intended purpose by the authority having jurisdiction.

When pressure vessels are designed and fabricated for use under Part 193 by using a more recent edition of the ASME BPVC than the 1992 version, the Operator is responsible to document the method used to determine equivalency and make this technical documentation available to PHMSA upon request. PHMSA will accept one of the following methods to demonstrate equivalency in accordance with NFPA 59A-2001, Section 1.2:

- Pressure vessels may be designed and fabricated to meet the requirements for test pressure and design margin factors found in the 1992 edition of the ASME BPVC; or,

- The maximum allowable working pressure (MAWP) for the pressure vessels may be reduced by the amount that results in a test pressure for all pressure vessels meeting the requirements in the 1992 edition of the ASME BPVC Section VIII, Division 1 or Division 2; or,

- Longitudinal, circumferential, nozzle-to-shell, tube sheet, header box, and nozzle-to-box header welds may be inspected by nondestructive examination (NDE). All longitudinal and circumferential welds and nozzle-to-shell welds for process nozzles six (6) inches or larger in diameter must be subject to 100% NDE. Accepted NDE methods are radiograph testing (RT), ultrasonic testing (UT), magnetic particle testing (MPT or MT), and dye penetrant testing (DPT or PT) along the entire weld length in accordance with the applicable sections of the current ASME Section VIII or other applicable standards. Longitudinal and circumferential welds must be subject to radiographic or ultrasonic testing; or,

- The operator of the LNG facility may develop, document, and implement a systematic approach, with annual inspections not to exceed 15-months, to ensure the long-term integrity of all its pressure vessels and pressure-relieving devices protecting these vessels within the LNG facility. The asset-management procedure must incorporate and comply with a current recognized and generally accepted American National Standards Institute (ANSI) standard such as the American Petroleum Institute (API) 510, "Pressure Vessel Inspection Code: In-service Inspection, Rating, Repair, and Alteration," 10th Edition. The procedures must be adopted into the operator's operations and maintenance (O&M) manual. The procedures must be updated, as needed, for the continuous, effective management of pressure vessel integrity that must include over pressure protection, corrosion, pipe wall thickness loss, cracking on both girth and longitudinal welds and steel body, loading stresses such as loads on nozzles from piping, valves, other components, and soil settlement and environmental deterioration of the pressure vessel due to weathering. Adoption and implementation of a pressure vessel asset management plan is in addition to the existing minimum requirements for operations, maintenance, and personnel qualifications and training found in 49 CFR Part 193 and NFPA 59A-2001. The operator must maintain all records and procedures for design, construction, testing, repairs, and O&M activities as required in API 510. The "Risk Based Inspection" option in Section 6.3 of API 510 is not an acceptable O&M inspection and evaluation method; or,

- The operator may submit to PHMSA another system, method, or device that is intended to demonstrate equivalency for evaluation and review on a case-by-case basis.

(DS) Design Spill Determination

DS1. The criteria and methodology used to identify single accidental leakage sources (SALS) to establish siting for my LNG facility were based on the failure rate table methodology. Do I need to submit a new or revised Design Spill Package to PHMSA based on the current SALS methodology?

No. PHMSA will not require the applicant to submit a new or revised Design Spill Package and will not retroactively apply the current SALS methodology to facilities that have received a previous PHMSA correspondence of no objection to their methodology for determining the SALS for design spills used in establishing the 49 CFR Part 193 siting requirements. If the applicant chooses to modify the design spills that were previously determined to be in compliance with Part 193 siting requirements, PHMSA will require an updated Design Spill Package as described in these FAQs. For those projects under FERC jurisdiction, the applicant will also need to file the updated information submitted to PHMSA on the FERC docket.

DS2. 49 CFR 193 requires that design spills for an LNG plant be selected according to NFPA 59A-2001 Paragraph 2.2.3.5. NFPA 59A requires the evaluation of accidental flow from "any single accidental leakage source" (SALS) but does not define this term. How should I select SALS events in an LNG plant?

For piping and equipment that handle LNG, flammable refrigerants, toxic components, and any other hazardous fluid, leakage sources may be chosen using the following guidelines. The SALS selection methodology, below, is applied to determine the maximum hole sizes of interest for the most significant releases of each hazardous fluid in each portion of the LNG plant. (The SALS selections are one component of design spill definition. Please refer to other FAQs for additional design spill definition topics.)

A. For piping segments, including transfer arms and double-ply construction expansion bellows, that are:
    1. Greater than or equal to 6 inches in diameter, a hole of 2 inches in diameter is applied at any location along the piping segment; and

2. Less than 6 inches in diameter, a full-bore rupture (guillotine failure) is applied at any location along the piping segment.

B. For single-ply construction expansion bellows, a hole size equivalent to a full-bore rupture of the diameter of the expansion joint is applied;

C. For pipe-in-pipe systems, an unobstructed release from an equivalent 1-inch diameter hole may be applied at the operating conditions of the inner pipe when:
   1. The system complies with NFPA 59A (2016) Section 9.11;
   2. The outer pipe is able to withstand the thermal shock, mechanical forces, and pressure loads of any single accidental leakage source from A and B above applied to the inner pipe; and
   3. Design, fabrication, examination, and testing of the pipe-in-pipe system, including calculations, can be demonstrated.

   The selection of any alternate hole size or release scenario definition will be reviewed on a case-by-case basis in lieu of the criteria defined above; and

D. For transfer hoses, a hole size equivalent to a full-bore rupture of the transfer hose is applied.

DS3. PHMSA reviews the design criteria for design spills on a case-by-case basis to determine compliance with Part 193. What information is required to assist PHMSA in its determination of the design spill criteria acceptable for use?

Applicants must provide a piping inventory table of LNG plant components in hazardous or flammable fluid service. At a minimum, the table should include piping of 2 inches in diameter and larger, as well as transfer hoses. The inventory table should be submitted in Excel (*.XL*) format. Separate tabs or lists should be used for each type of hazardous fluid, with demarcation of all of the final design spill selections. The table should include the following information:

a. Line segment scenario number to identify the leakage source scenario;
b. Description of line segment purpose (LNG rundown header, KO Drum drain, relief valve inlet, level gauge instrument connection, etc.);
c. General plant area or service (e.g. liquefaction train, refrigerant storage, marine area, etc.), unless the entire project is confined to one area;
d. Beginning point location (e.g., exchanger outlet flange) for each line;
e. Ending point location (e.g., pump suction nozzle) for each line;
f. Line diameter;
g. Hazardous fluid service (LNG, natural gas, refrigerants (such as propane, ethane, mixed refrigerant), ammonia, natural gas liquids (NGL) or gas condensate, acid gas (containing hydrogen sulfide), etc.);
h. P&ID drawing number reference(s) for each segment;
i. Piping line designation on P&ID
j. Fluid conditions within the line segment (e.g., fluid phase (liquid or vapor); density (lb/ft3); pressure (psig); temperature (°F); mass flow rate, (lb/hr); composition of mixed refrigerants, NGL/condensates, acid gas (mol%));
k. Process flow diagram and corresponding heat and material balance stream number;

l. Heat and material balance case selection;
m. Leakage source hole size;
n. Calculated total release flow rate (lb/hr);
o. Calculated depressurization or equilibrium pressure used for release flow rate (psig);
p. Release duration;
q. For potential design spill selections, include release height, orientation, rainout percentage, total vapor mass flow rate (lb/hr), de-inventory duration, and screening dispersion distance (ft); and
r. Comments, including any pump run out percentages used, as well as justifications or other details for the final design spills selected.

DS4. Is the largest size hole always used as the hole size in release modeling?

Not necessarily. For any defined maximum hole size, the applicant must demonstrate that that the hole size selected produces the greatest vapor dispersion distance when accounting for the mechanisms of flashing, jetting, aerosol formation, and rain-out. If a smaller hole size creates a larger vapor dispersion hazard distance, that smaller hole size should be used to define the design spill event. This applies to all single accidental leakage sources, including failures at piping, piping connections, and transfer hoses.

DS5. What are the proper release height and orientation to use for a design spill?

For each design spill identified, the release height should be the one that defines the largest hazard distances, bounded within the actual or anticipated heights of the equipment and piping.

Release orientation should be horizontal for each design spill unless a vertical orientation would produce higher consequences. Vertical orientations that provide higher consequences generally include:

- vertically upward for liquid releases with rainout greater than 25% (e.g., heavy hydrocarbons, pentane, etc.);
- vertically downward for gaseous releases (e.g., acid gas) ; and
- where mitigation measures would control or redirect the release, specific release orientations may be considered (e.g., pipe shrouding that directs a fluid downward, the downward direction may be applied).

A sensitivity analysis should be provided to demonstrate which release orientation scenario (horizontal, vertical upward, or vertical downward, as applicable) results in the largest hazard distance.

DS6. How are release locations defined?

For single-ply expansion joint or transfer hose failures, the release location can be identified at the specific point of that component in the LNG plant. For piping segments, the selected hole can occur at any location along the piping segment. If vapor barriers, shrouds, or pipe-in-pipe designs are used to reduce the vapor dispersion distance, locations potentially not impacted by the vapor barrier, shroud, or pipe-in-pipe should also be selected.

DS7. How do I determine the process conditions to evaluate for hazard modeling?

Process conditions should be based on heat and material balance modes of operation and design case

(e.g., rich, lean, average, etc.) that produce the worst case dispersion results from flashing and jetting and liquid releases. The leakage sources from branch connections should be considered using the potential operational conditions along the pipe as well as the potential operational conditions that could be experienced at or near the branch pipe connection to a main process line. In cases that would reduce the back pressure on pump(s) or compressor(s), the flow rates should consider the potential increased pump or compressor flow determined by the pump and compressor curve(s) as detailed in DS10 and also consider the decrease in temperature and pressure during runout conditions.

DS8. What considerations should be given to system inventory and spill duration in the design spill calculations?

The applicant may need to demonstrate the selected design spill duration. The release modeling should account for the available system inventory (including piping, process vessels, storage vessels, and other process equipment) when calculating the design spill duration as follows:

A. Applicants may use a 10-minute spill duration if the process design includes acceptable detection, isolation, and shutdown.
B. For long and large-bore piping with a significant distance between isolation valves (emergency shutdown or manually or remotely operated), as well as releases from process or storage vessels, the dispersion modeling may continue beyond the 10-minute design spill duration to account for the inventory volume in the piping and the entire contents of any vessels at maximum design level(s), unless the dispersion modeling endpoint reaches its furthest extent in a shorter time.
C. A release duration of less than 10 minutes may be used for release scenarios where the available system inventory may be depleted in less than 10 minutes. The applicant may elect this shorter duration based on demonstrable surveillance, shutdown, and isolation design with valve closures from emergency shutdowns or remote valve operation per NFPA 59A-2001. All scenario isolation valves must be protected from failure, including fire and external impacts. The shutdown system must meet a safety integrity level (SIL) 2 or SIL3 reliability design and maintenance requirements in accordance with the International Society of Automation (ISA) 84 standards.

DS9. How should I consider a release from a process or storage vessel in the design spill calculations?

For systems with a process or storage vessel, the applicant should first select the appropriate release scenarios that account for the pipe flow (normal operational or pump run out) from the piping connecting to a vessel, based on FAQs DS7 and DS10. Furthermore, a comparative release scenario should be provided using the process or storage pressure from the vessel. This pressurized release rate may be calculated using the orifice equation at full operational system pressure, including the hydrostatic head from the maximum liquid design level, for the entire design spill duration. This corresponding duration would last until the inventory that could be isolated by valves would be depleted. The applicant should then perform a comparative screening to determine whether the piping or the vessel-pressurized scenario would result in the worst case dispersion distance.

Alternatively, transient flow scenarios may be evaluated to more precisely account for the effects of demonstrable surveillance, shutdown, and de-inventorying of the piping and vessel(s) on the release rate. A transient flow scenario should account for the most significant leakage source release from piping and the vessel, taking into account the normal flow into the vessel and the pressurized head space in the vessel.

DS10. Do I need to consider pump run-out in release scenario calculations?

Applicants should use pump run-out (greater flow than in normal pump flow operations) in failure calculations if the pump design allows increases in flow as the discharge pressure is reduced, unless acceptable preventive measures are used that prevent the pump from run out conditions. Pump runout parameters are presented by the pump manufacturer as a pump curve that shows flow increasing as the discharge pressure decreases. If pump run-out flows are not known at the time of submittal, engineering estimates may be employed provisionally.

Acceptable preventive measures include pump interlocks or safety instrumented prevention systems that meet safety integrity level (SIL) 2 or SIL3 reliability design and maintenance requirements in accordance with the International Society of Automation (ISA) 84 standards.

DS11. Should multiple pumps be considered when calculating the greatest flow from a spill to size impoundments or when defining a single accidental leakage source event?

Where the greatest flow is potentially fed from multiple pumps, calculate the flow to size impoundments assuming that all pumps are running, unless acceptable preventive measures are used that prevent all pumps from running concurrently.

Where a piping system utilizes multiple pumps, calculate the design spill based on the total flow from all system pumps running, unless acceptable preventive measures are used that prevent or limit all pumps from running concurrently.

Acceptable preventive measures include pump interlocks or safety instrumented prevention systems that meet safety integrity level (SIL) 2 or SIL 3 reliability design and maintenance requirements in accordance with the International Society of Automation (ISA) 84 standards.

(H) Hazards and Hazards Modeling

H1. Other than the flammable vapor dispersion and thermal radiation from hazards associated with LNG, what other hazards should be evaluated in the siting analysis for an LNG plant?

According to NFPA 59A-2001 Paragraph 2.1.1(d), (incorporated by reference in 49 CFR Part 193), all hazards that can affect the safety of the public or plant personnel are to be considered. In addition to LNG, the applicant should consider hazards associated with flammable gases, flammable refrigerants, flammable or combustible liquids, or acutely toxic materials. If present at the LNG plant, hazards including vapor dispersion from liquid pools, vapor dispersion from jetting and flashing phenomena, thermal radiation from pool fires, thermal radiation from fires involving jetting and flashing phenomena (jet fires), overpressure from vapor cloud ignitions, toxic gas dispersion, and boiling liquid expanding vapor explosions (BLEVEs) involving pressurized storage vessels should be included in an LNG plant's hazard evaluation.

H2. My LNG plant includes some toxic materials. What considerations should be given to accidental releases of these materials and the associated hazard modeling?

While the hazards associated with toxic substances at an LNG plant are not prescriptively covered in 49 CFR Part 193, their consideration is required by NFPA 59A-2001 Paragraph 2.1.1(d) (incorporated by reference in 49 CFR Part 193), which requires that all hazards that can affect the safety of the public or plant personnel be considered.

Many toxic substances stored above certain quantities are regulated under Appendix A of the EPA's "Risk Management Program for Chemical Accidental Release Prevention" (RMP, 40 CFR 68) and OSHA's "Process Safety Management of Highly Hazardous Chemicals" (PSM, 29 CFR 1910.119). Compliance with EPA's RMP and OSHA's PSM regulations is a sufficient approach to comply with NFPA 59A Paragraph 2.1.1(d). PHMSA does not have authority to enforce EPA or OSHA regulations, but requires operator compliance with NFPA 59A Paragraph 2.1.1(d).

Consideration of toxic hazards must include dispersion modeling appropriate for the toxic substance and its behavior upon release, as well as incorporating safety measures of the design and operation of the facility. Applicants may propose alternative modeling methods to comply with NFPA 59A Paragraph 2.1.1(d) for toxic substances. The release scenario selection methodology should be consistent with the selection methodology defined in FAQs DS2 and DS4 through DS11. In addition, the dispersion modeling should consider a method to account for the potential combined impacts of toxic components (e.g., the principle used in the Compressed Gas Association P-20 methodology). The AEGL values are the preferred endpoints to be used in the calculations with an exposure duration corresponding to the release event, up to 1 hour. Because there are no specific exclusion zones that are to be defined for toxic materials, the offsite impacts at each proposed LNG plant will be evaluated on a case-by-case basis.

H3. Materials received, stored, or used at my LNG plant could generate overpressures from a vapor cloud explosion. What considerations should be given to vapor cloud explosions and the associated hazard modeling?

While explosion overpressure is not prescriptively covered in 49 CFR Part 193, its consideration is required by NFPA 59A-2001 Paragraph 2.1.1(d) (incorporated by reference in 49 CFR Part 193), which requires that all hazards that can affect the safety of the public or plant personnel be considered. Vapor cloud explosion modeling should involve consideration of vapor dispersion modeling results, evaluation of areas of confinement and congestion, and the potential reactivity of released materials. The use of the 1.0 psi overpressure endpoint is appropriate for explosion modeling, and is consistent with the EPA's "Risk Management Program for Chemical Accidental Release Prevention" (RMP, 40 CFR 68). Because there are no specific exclusion zones that are to be defined for explosion overpressure impacts, the offsite impacts at each proposed LNG plant will be evaluated on a case-by-case basis.

H4. What wind direction should be used in exclusion zone and other hazard calculations?

For most hazard calculations, the exclusion distance or hazard distance is calculated independent of wind direction. If the wind direction is important in the modeling methods used, the direction used should be toward the nearest property line. Additional wind directions may also need to be analyzed if the hazard could extend beyond other property lines or cause other unique hazards.

H5. Can an exclusion zone extend beyond the operator's LNG plant property line?

As long as the facility is in operation, the operator is responsible for assuring compliance with the limitations on land use within exclusion zones, according to the descriptions in NFPA 59A Sections 2.2.3.2, 2.2.3.3, and 2.2.3.4. For example, an exclusion zone that extends past a property line into a navigable body of water or onto a public road is typically acceptable. This may not hold true if that body of water contains a dock or pier that is not controlled by the operator of the LNG plant, or if another entity could erect a building or members of the public could assemble within the exclusion zone. It is possible to assure compliance by legal agreement with a property owner affected by the exclusion zone, such that the land use is restricted for the life of the LNG plant.

H6. In addition to DEGADIS 2.1 and FEM3A, Section 193.2059 Flammable vapor dispersion protection provides for the use of alternate models approved by US DOT PHMSA. What other models have been approved?

On October 7, 2011, PHMSA approved two alternate models for the determination of vapor dispersion exclusion zones under 49 C.F.R. § 193.2059: FLACS 9.1 Release 2 and Phast versions 6.6 and 6.7. Each model has been validated for use in certain conditions in accordance with the Model Evaluation Protocol (MEP) as described in M. J. Ivings et al., Evaluating Vapor Dispersion Models for Safety Analysis of LNG Facilities Research Project: Technical Report (Apr. 2007) (available at http://www.nfpa.org under archived reports). The approval letters discuss the limitations for each modeling software.

On April 13, 2023, under 49 C.F.R. §§ 190.9 and 193.2059, PHMSA approved a petition requesting use of Phast version 8.4 (an updated version of Phast) as an additional model for calculating the vapor dispersion exclusion zones for Part 193-regulated LNG facilities. PHMSA evaluated the suitability of Phast version 8.4 using the process described in the 2nd edition of the Evaluating Vapor Dispersion Models for Safety Analysis of LNG Facilities (Ivings et al., 2016) (available at http://www.nfpa.org). PHMSA approved Phast version 8.4 for calculation of the vapor dispersion exclusion zones only with the limitations described in the final environmental assessment and if the uncertainty factors are applied as described below:

- Phast version 8.4 may be used only with an uncertainty factor of two as an alternate flammable vapor-gas dispersion model when computing flammable vapor dispersion distances to the lower flammable limit (LFL) (i.e., ½ LFL). This factor of two is based on Phast version 8.4's performance regarding the predicted distance to the LFL and ½ LFL. The vapor dispersion exclusion zones are the distances when the flammable vapor clouds reach the ½ LFL.

- Specifically for low wind speed (i.e., 1 to 3 meters per second) and high atmospheric stability (i.e., Pasquill stability classes E and F) conditions, PHMSA requires at least a distance uncertainty factor of 2.5 to account for Phast version 8.4's underpredicted results against the Burro 8 trial. According to final environmental assessment, "[t]he predicted distance to ½ LFL is also below the LFL distance based on experimental data. Even if the predicted LFL distances were doubled for either short or long time-averaged results, the distance would still be below that based on experimental data." Therefore, an uncertainty factor of 2.5 must be applied to the distance at the LFL for low wind speed and high atmospheric stability conditions. The vapor dispersion exclusion zones are 2.5 times the distances when the flammable vapor clouds reach the LFL.

For detailed information regarding the conditions for which the models were validated, see PHMSA's final decision at:

FLACS https://www.regulations.gov/search/docket?filter=PHMSA-2011-0101

Phast v6.6/6.7 https://www.regulations.gov/search/docket?filter=phmsa-2011-0075

Phast v8.4 https://www.regulations.gov/search?filter=phmsa-2021-0041

H7. Does US DOT PHMSA prescribe source term models for flammable vapor dispersion modeling?

While PHMSA does not prescribe or approve source term models, the source term model must have a creditable scientific basis and must not ignore any phenomena that can influence vapor formation during discharge from containment, conveyance to an impoundment, and retention within the impoundment. In July, 2010 PHMSA communicated in interpretation PI-10-0021 that the SOURCE5 model does not satisfy the PHMSA requirements for a source term model. The interpretation can be viewed at: https://www.phmsa.dot.gov/regulations/title49/interp/PI-10-0021.

H8. Can mitigation measures be used in exclusion zone and other hazard calculations?

For most hazard calculations, passive mitigation measures are inherently acceptable, provided that their design and implementation can be technically supported and that they do not introduce other harmful consequences.

Active or procedural mitigation measures are generally not included exclusion zone or hazard zone calculations. However, PHMSA will review the proposed inclusion of such measures on a case-by-case basis, provided that proper supporting technical justification and documentation is submitted.

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